FILED
10/22/26
01:28 PM
A2605018

Safety Policy Division Evaluation Report on Southern California Edison's 2026 RAMP Application (A.) 26-05-018

October 23, 2026

California Public Utilities Commission

Table of Contents

Executive Summary 1

Background 5

Explanation of Terms 9

Evaluation Scope and Methodology 11

Key Differences between SCE's 2022 and 2026 RAMP 14

SCE's RAMP Risk Selection Process 16

- Ranked List of Risks 17

Evaluation of SCE's Risk Model and Benefit-Cost Ratio Methodology 21

Evaluation of RAMP Chapters 37

- 1. Wildfire and PSPS Risk 37
- 2. Overhead Equipment Failure Risk 136
- 3. Underground Equipment Failure Risk 151
- 4. Employee Safety Risk 166
- 5. Contractor Safety Risk 186
- 6. Public Safety Risk Not Attributable to Asset Failure 204
- 7. Cyber Attack 214
- 8. Seismic Risk 226
- 9. Physical Security 246
- 10. Hydro Asset Failure Risk 253
- 11. Safety Culture, Organizational Structure, Executive and Utility Board Engagement, and Compensation Policies Related to Safety 275
- 12. Environmental and Social Justice Pilot Study and White Paper 284

Safety Policy Division Evaluation Team 294

Acknowledgements 295

- A Note on Informal Comments 295

Informal Comments 296

Executive Summary

The Safety Policy Division of the CPUC is required by the California Public Utilities Commission (Commission or CPUC) to evaluate Risk Assessment and Mitigation Phase (RAMP) applications. The Southern California Edison Company (SCE) filed its 2026 RAMP application with the CPUC on May 15, 2026, in advance of its Test Year 2029 General Rate Case application. SCE's 2026 RAMP application covers expenditures from 2029 to 2032. The CPUC's Safety Policy Division evaluated SCE's RAMP application (including work papers) according to the requirements of the Risk-Based Decision-Making Framework proceeding as adopted in Decisions 22-12-027, 24-05-064, and 25-08-032, commonly referred to as the Phase 2, Phase 3, and Phase 4 Decisions, respectively. The directions provided by the Scoping Ruling in A.26-05-018 also guided this evaluation. This Executive Summary provides the main conclusions of the Safety Policy Division's evaluation. Overall, SCE's 2026 RAMP application meets the requirements set forth in the Risk-Based Decision-Making Framework's Phase 2, 3, and 4 Decisions. Where Safety Policy Division identified a deficiency in SCE's RAMP, it describes the deficiency in terms of observations and findings, and, where appropriate, offers recommendations for improvement. Safety Policy Division had thirty-five findings for the wildfire and Public Safety Power Shutoff risk chapter and a total of fourty-nine findings for the remaining risk chapters. Findings and recommendations for improvement are at the end of each risk chapter.

SCE should address the observations and findings described in the Safety Policy Division evaluation report before filing its Test Year 2029 General Rate Case application.

Safety Policy Division's significant cross-cutting findings that apply to SCE's 2026 RAMP:

1. The evaluation was impeded by typos, math errors, missing tables, and other proofreading errors.
2. The exclusion of secondary impacts (like outages from seismic events, cyber attacks, or underground explosions) from the risk assessment leaves significant risk unassessed.
3. SCE lacks explanations or provides insufficient explanations in some cases where it does not define Risk Reporting Units, but some controls may fall under that requirement (pertaining to public safety risk not attributable to asset failure, cyber attack, seismic, and physical security).

The bulk of this report is an analysis of SCE's approach to wildfire risk. Below is a summary of the Safety Policy Division's analysis of SCE's RAMP chapter and associated filings regarding wildfire risk.

General Conclusion Regarding SCE's Approach to Wildfire Risk

SCE has made improvements in its ability to represent wildfire consequences, climate-related conditions, and community exposure. However, Safety Policy Division identifies material deficiencies in risk coverage, model calibration and validation, project prioritization, and benefit-cost ratio calculations. These deficiencies prevent Safety Policy Division from verifying that the reported risk estimates and benefit-cost comparisons consistently support SCE's proposed mitigation selections.

Safety Policy Division has 35 findings and associated recommendations regarding SCE's approach to wildfire risk. SCE should correct calculation errors, reconcile inconsistent data and results, disclose omitted

risks, and provide additional model validation in its Test Year 2029 General Rate Case application and future RAMP filings. The findings concern both the magnitude of estimated risk reduction and the comparability of competing investments; the findings do not establish a single adjustment applicable to all reported benefit-cost ratios.

Principal Findings Regarding SCE's Approach to Wildfire Risk

1. Idle Facilities and Transmission Risk (findings 33-35): SCE does not model an explicit ignition pathway for idle or out-of-service facilities, although it strengthened grounding practices for idle transmission lines before filing its 2026 RAMP. SCE also calculates transmission wildfire risk without reporting a separate transmission-specific risk quantity. Safety Policy Division recommends quantifying idle-facility risk or justifying its exclusion, reconciling the risk model with operational actions, and reporting wildfire risk separately for distribution, subtransmission, and transmission facilities.
2. Reconciliation of Mitigation Benefits (finding 27): Safety Policy Division calculates approximately $17.26 billion in Risk Reporting Unit-level mitigation benefits from SCE's benefit-cost ratio work paper. Applying SCE's documented discounting, inflation, and useful-life assumptions to the annualized risk reduction in its application summary tables produces an upper-bound benefit estimate of approximately $4.30 billion. Covered conductor and targeted undergrounding alone have combined work-paper benefits of approximately $9.9 billion. Safety Policy Division cannot reconcile these amounts and recommends that SCE identify the source of the discrepancies, correct erroneous figures, and explain the effects on individual benefit-cost ratios.
3. Operations and Maintenance Cost Treatment and Cost Comparisons (findings 22-26, 28): SCE uses approximately $62,000 per mile per year of existing overhead operations and maintenance cost as a proxy for covered conductor operating costs while treating that same baseline cost as avoided operations and maintenance cost for targeted undergrounding. Safety Policy Division finds that this inconsistent baseline treatment depresses the benefit-cost ratio for covered conductor relative to targeted undergrounding. Separately, Safety Policy Division identifies a formula for the net cost of targeted undergrounding operations and maintenance that counts the new underground operating cost twice. Reported unit costs also differ between SCE's RAMP application and benefit-cost ratio work paper, increasing for covered conductor but decreasing for targeted undergrounding. Safety Policy Division recommends correcting the formula, substantiating operations and maintenance cost assumptions, reconciling cost totals, and calculating incremental costs and benefits against one consistent no-build baseline.
4. Tranche Assignments and Mitigation Prioritization (findings 8-11): SPD did not find a crosswalk linking mitigation segments to Risk Reporting Units, risk tranches, and supporting benefit-cost ratios. SCE reports tranche assignments for Risk Reporting Units it already selected for mitigation rather than the full set of possible projects available for prioritization, and some reported consequence values are inconsistent with assigned quintiles. Safety Policy Division cannot verify that SCE's tranching framework performs its stated prioritization function. SCE should provide complete tranche assignments, the assignment methodology, and a segment-level crosswalk, and reconcile risk and mitigation benefits on a common scope.

5. Wildfire Risk Scope and Residual Risk (findings 1, 12-13): SCE excludes underground assets and assets outside its High Fire Risk Area from its reported wildfire risk scope. Its data nevertheless show 357 underground-asset ignitions out of 4,286 total ignitions during 2014-2025, and it already models risk outside its High Fire Risk Area without presenting that risk in its RAMP. SCE also omits secondary and service line risks from current probability-of-ignition modeling and circuit rankings. Safety Policy Division recommends that SCE quantify these risks, incorporate them into its baseline and residual-risk reporting, or provide quantitative support for their exclusion.
6. Risk Scalars and Reliability Valuation (findings 2-7): SCE's community vulnerability adjustments can change benefit-cost ratios and mitigation selection. Safety Policy Division is concerned that population-share scalars may reflect circuit size as much as vulnerability, while Community Fire Risk Area adjustments increase monetized safety consequences by approximately 55.6 to 100 percent wherever they apply. Reliability values are derived from routine outages averaging approximately 139 minutes, although wildfire scenarios assume approximately 480 minutes. In SCE's example, non-residential customers account for approximately 98 percent of monetized reliability value but less than 10 percent of interrupted customer minutes. Safety Policy Division recommends SCE use parallel scaled and unscaled results and reliability values differentiated by customer class and High Fire Risk Area status, using inputs appropriate to modeled outage durations.
7. Ignition Frequencies and the No-Build Baseline (findings 14-15, 17): SCE reports conflicting annual equipment/facility-failure ignition frequencies of 20.3 and 52.7. Its historical ignition average also spans years with substantially different hardening levels without normalizing those observations for completed hardening. Changes in detection and documentation practices introduce further uncertainty into the Fire Investigation Preliminary Analysis calibration dataset. Safety Policy Division recommends reconciling the frequencies, accounting for completed hardening in the 2029 no-build baseline, and demonstrating that detection changes do not materially distort total ignition estimates or relative driver weights.
8. Consequence Modeling and Validation (findings 16, 18-19): Safety Policy Division questions the alignment between the frequency of SCE's highest-severity consequence category, Condition 3, and the structure-loss consequences assigned to that category. SCE also has not demonstrated that scaled asset-level Wildfire Integrated Model values reconcile to the coarser model's expected values or systematically validate the Wildfire Integrated Model's ability to predict relative consequences and absolute risk. Safety Policy Division recommends reconciling consequence classifications and frequencies, justifying the scaling method, and testing model outputs against historical fire locations and consequences.
9. Incremental Benefits and Costs of Rapid Earth Fault Current Limiters (findings 29-31): SCE combines the costs and benefits of covered conductor with rapid earth fault current limiters without establishing a stand-alone incremental benefit-cost ratio for rapid earth fault current limiters. This can obscure the value of adding rapid earth fault current limiters to circuits with planned or completed covered conductor and may credit rapid earth fault current limiters with risk reduction already achieved by covered conductor. SCE also includes the full cost of rapid earth fault current limiter installation while excluding benefits outside its High Fire Risk Area. In 20 of 40 Risk Reporting Units evaluated for both options, covered conductor with rapid earth fault current

limiters has a lower reported benefit than covered conductor alone despite greater modeled risk reduction. Safety Policy Division recommends SCE calculate separate incremental benefit-cost ratios and reconcile these results.

10. Controls with Low Benefit-Cost Ratios and Alternative Plans (findings 20-21, 32): Two vegetation management controls account for approximately $1.28 billion in proposed spending but have benefit-cost ratios of 0.51 and 0.53 using the weighted-average cost of capital. SCE's ten customer-facing Public Safety Power Shutoff programs have an overall benefit-cost ratio of 0.22 on the same basis. Although compliance obligations and Commission direction may justify these programs, SCE should distinguish mandated from discretionary scope and justify above-compliance spending. Safety Policy Division also recommends substantiating the unusually large incremental risk reduction attributed to 37 additional undergrounding miles in its wildfire risk Alternative Plan 2, including locations previously hardened with covered conductor.

Background

The Safety Policy Division (SPD) of the California Public Utilities Commission (Commission or CPUC) is responsible for evaluating the 2026 Risk Assessment and Mitigation Phase (RAMP) application of Southern California Edison (SCE). This report presents SPD's evaluation of SCE's 2026 RAMP application.

In accordance with the schedule adopted in Decision (D.)20-01-002,[1] SCE filed its RAMP application (proceeding number Application [A.] 26-05-018) with the CPUC on May 15, 2026, in advance of its Test Year 2029 General Rate Case (GRC) application.[2, 3] SCE's 2026 RAMP application covers expenditures from 2029 to 2032. The directions provided by the Scoping Ruling in A.26-05-018 guide this evaluation.

The requirements of the Risk-Based Decision-Making Framework (RDF)[4] as adopted in the RDF's Phase 2, Phase 3, and Phase 4 Decisions apply to this RAMP proceeding. [5, 6, 7]

Phase 2 requires the use of cost-benefit ratios (CBRs) in RAMP and GRC filings, replacing the earlier risk-spend efficiency metric.[8] CBRs are intended to be used by the utility to justify proposed risk mitigations.

---

[1] Decision Modifying the Commission's Rate Case Plan for Energy Utilities (D.20-01-002 of Jan. 22, 2020), Appendix B "Schedule for the Transition from the Current Three-Year GRC Cycle to the Four-Year GRC Cycle" (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF, accessed May 27, 2026).

[2] A.26-05-018 proceeding docket (https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:A2605018 , accessed June 12, 2026).

[3] SCE's RAMP work papers, including its pre-filing white papers (filed under Chapter 2 work papers), are available on the SCE web page CPUC Open Proceedings under 2026 RAMP (https://www.sce.com/regulatory/regulatory-information/open-proceedings/cpuc-open-proceedings; https://edisonintl.sharepoint.com/teams/Public/regpublic/Regulatory%20Documents/Forms/RIMS%20Doc%20Set%20View.aspx?id=%2Fteams%2FPublic%2Fregpublic%2FRegulatory%20Documents%2FPD%2FCPUC%2F22361, both accessed June 12, 2026).

[4] The RDF is described in Rulemaking (R.) 20-07-013 To Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities (https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2007013, accessed May 27, 2026).

[5] Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots with Appendices (D.22-12-027 of Dec. 21, 2022) (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668, accessed May 27, 2026).

[6] Phase 3 Decision with Appendices (D.24-05-064 of June 6, 2024). (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=533099839, accessed May 27, 2026).

[7] Phase 4 Decision with Appendices (D.25-08-032 of Aug. 29, 2025). (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=578198350, accessed May 27, 2026). This decision closed R.20-07-013.

[8] See Appendix A of D.22-12-027 for a description of the RDF's cost-benefit approach (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043720.PDF, accessed May 27, 2026).

The numerator of the CBR is the net present value of risk reduction benefits and the denominator is the net present value of mitigation costs. This approach should produce a uniform basis for comparing mitigation alternatives. Because the ratio is expressed as benefit/cost, the Phase 4 Decision updated the term from cost-benefit ratios to benefit-cost ratios (BCRs).

The Phase 3 Decision introduced the following:

- **Tranching Methodology:** Phase 3 established the quintile tranching approach as the default best practice. In this approach, utilities must use likelihood of a risk event (LoRE)/consequence of a risk event (CoRE) quintile tranches (five tranches of each), producing 25 tranches in all cases where the quintile method is applied, unless a utility justifies an alternative.[9] SCE deviated from this default in its 2026 RAMP by submitting a white paper proposing alternative tranching methods for some RAMP risks (employee and contractor safety, cyber attack, hydro dam failure, seismic, physical security, and public safety risk not attributable to asset failure).[10]
- **Tail Risk Analysis:** Phase 3 established how to account for low-probability, high-consequence events in risk modeling.[11]
- **Convex Risk-Averse Scaling Functions:** Phase 3 introduced the option to use a risk averse approach by applying scaling functions that weight higher-consequence events more heavily. If a utility elects to address tail risk using the power law or other statistical approach and chooses to present risk-adjusted attribute levels using a convex scaling function, then it must also present risk-adjusted attribute levels using a linear scaling function.[12]
- **Post-Test-Year (PTY) BCRs:** Phase 3 required utilities to present BCRs (formerly CBRs) for each post-test-year and aggregate PTY/GRC-cycle BCRs by tranche. SCE's 2026 RAMP therefore extends its BCR analysis through 2032.[13]
- **Discount Rate Scenarios:** Phase 3 required BCRs to be calculated under three discount rate scenarios: weighted-average cost of capital (WACC), a 2 percent social discount rate, and a hybrid rate.[14] SCE's 2026 RAMP presented its BCRs under these discount rate scenarios. In 2026, the

[9] D.24-05-064, Appendix A, Row 14, pp. A-13-A-14.

[10] SCE submitted "SCE 2026 RAMP Tranching White Paper" November 3, 2025; SCE submitted the "Chapter 2 Risk Model and BRC [sic] Methodology Tranching Whitepaper," indicating updates to its approach to tranching for 2026, May 27, 2026.

[11] D. 24-05-064, Appendix A, Row 24, p. A-15.

[12] D. 24-05-064, Appendix A, Row 7, p. A-8.

[13] D. 24-05-064, Appendix A, Row 26, p. A-17.

[14] D. 24-05-064, Appendix A, Row 25, p. A-16. Note that this row is only legible in the Word version of the Phase 3 Decision's Appendix A (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M533/K206/533206241.docx, accessed July 1, 2026). It is obscured in the PDF version.

WACC is 7.59 percent.[15] In the hybrid approach "the safety and reliability components of the numerator are discounted using a Commission-specified formula [6.1 percent], while the financial component of the numerator, as well as the entire denominator, are discounted using SCE's most recent WACC [7.59 percent]."[16] The hybrid approach is a "middle ground between purely societal and purely financial discounting perspectives."[17]

The Phase 4 Decision introduced further requirements and clarifications, including:

- **Portfolio Optimization:** Phase 4 introduced the use of an optimization model where the objective to be maximized is risk reduction, the constraint is a given budget level in dollars, and the decision variable (i.e., what is selected by the optimization algorithm to maximize the objective function) is whether a given mitigation is included in the portfolio or not.[18]
- **Mitigation Portfolios and Mitigation Groups:** Phase 4 introduced collections of risk mitigation/control programs that can have their own BCRs, enabling comparison of portfolios or groups of mitigations.[19]
- **Risk Reporting Units (RRU):** Phase 4 introduced the idea of units for proposing risk mitigation that aggregate a group of contiguous assets or systems that exhibit high levels of risk. RRUs must have elements in common that must include, but are not limited to, consequence attributes, risk level, line-item costs, BCRs, work units, and time.[20] Risks that the Phase 4 Decision exempted from needing RRUs defined are PSPS and protective equipment device settings. Other than these, the Phase 4 Decision required SCE to define RRUs for mitigation programs costing $10 million or more. For the purposes of this report, SPD is interpreting the $10 million threshold to pertain to the cost of the mitigation program over the course of the four-year RAMP cycle.[21]

---

[15] Application of Southern California Edison Company (U 338-E) Regarding 2026 Risk Assessment Mitigation Phase (SCE 2026 RAMP), Chapter 2 "Risk Model and BCR Methodology," p. 26.

[16] SCE 2026 RAMP, Chapter 2 "Risk Model and BCR Methodology," p. 26.

[17] SCE 2026 RAMP, Chapter 2 "Risk Model and BCR Methodology," p. 27.

[18] D.25-08-032, Appendix A, Definitions, p. A-6; Rows 25.1-25.2, pp. A-19-A-20.

[19] D.25-08-032, Appendix A, Rows 25.1-25.2, p. A-20, and Row 26, pp. A-21-A-22.

[20] D.25-08-032, Appendix A, Definitions, p. A-7; Row 15.1, pp. A-16-A-17.

[21] D.25-08-032, p. 67 ("establishing a cost threshold for mitigation and control programs based on the same thresholds found in the Phase 1 Decision…"), which in turn points to the RDF Phase 1 Decision, D.21-11-009, p. 141, where the cost threshold is described as "the aggregate cost over the upcoming GRC funding period."

- **RRU Data Reports**: Phase 4 introduced new data reporting requirements, including submitting with each RAMP filing a dataset of RRUs for each mitigation and control program, ranking each RRU by BCR.[22]
- **RAMP Data Template:** Phase 4 introduced a set of seven templates for presenting data supporting the utility's risk assessment: (1) Data Set, (2) Cost Breakdown, (3) Risk Model Change Tracker, (4) HFTD[23] and Associated Asset, (5) HCA/MCA and Associated Assets (gas only, not applicable to SCE), (6) Financial Inputs, and (7) Interruption Cost Estimate (ICE) Calculator Inputs.[24, 25] The goal of these templates is to increase transparency in utility reporting.
- **Overall Residual Risk Reporting:** Phase 4 introduced the requirement to calculate the risk on the utility's assets or systems for a given enterprise risk presented in the RAMP filing, after accounting for the historical progress of risk reduction since the utility's first RAMP filing.[26]
- **Consequence Distributions:** Phase 4 introduced the requirement of showing the potential consequences of a risk event (CoRE) as a probability distribution. For each enterprise risk, the utility must explain how it derived the probability distribution for the potential CoRE.[27]
- **Risk Mitigation Accountability Reporting (RMAR)**: Phase 4 introduced a new requirement related to the risk assessment stage of the RAMP where the utility must produce a summary of the Risk Mitigation Accountability Report Reporting Phase for each risk the utility intends to address in its RAMP application.[28] Note that at this writing, the CPUC is in the process of establishing its schedule for RMAR filings and other report details in a Staff Resolution yet to be resolved.[29] Appropriately, SCE did not submit an RMAR summary with its 2026 RAMP application.

[22] D.25-08-032, Appendix A, Row 26, pp. A-21-A-22

[23] HFTD: the CPUC-defined high fire threat district.

[24] D.25-08-032, Appendix D "RAMP Data Template and Guidelines."

[25] CPUC web page RAMP Data Template and Guidelines (https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/risk-assessment-and-mitigation-phase/ramp-data-template-and-guidelines, accessed July 1, 2026).

[26] D.25-08-032, Appendix A, Row 9, p. A-12.

[27] D.25-08-032, Appendix A, Row 10, p. A-13.

[28] D.25-08-032, Appendix A, Row 9, p. A-12.

[29] D.25-08-032, Conclusions of Law 31-39, pp. 127-128.

Explanation of Terms

See the governing documents of the RAMP (Appendix A of each of the RDF Phase 2, Phase3, and Phase 4 Decisions) for the definitions of additional terms relevant to this evaluation report.

2026 RAMP: SCE's 2026 Risk Assessment and Mitigation Phase (RAMP) application. Utilities refer to RAMP applications by the calendar year in which they file them. SCE filed its 2026 RAMP application (2026 RAMP) in advance of its Test Year 2029 General Rate Case (GRC) application. SCE's 2026 RAMP covers expenditures from 2029 to 2032.

BCR: Formerly called the cost-benefit ratio (CBR), the benefit-cost ratio (BCR) is defined as the ratio of the dollar value of mitigation benefit (numerator) divided by the mitigation cost estimate (denominator). Here is a simplified formula for a BCR:

$$BCR = \frac{\text{Present Value of Mitigation Benefit}}{\text{Present Value of Mitigation Cost}}$$

BCRs are used by utilities to help prioritize mitigations that deliver the greatest risk reduction per dollar spent. This definition is consistent with the adopted definition in the governing frameworks for this RAMP (Appendix A of the RDF Phase 2, 3, and 4 Decisions).

Exposure: The assets or resources subject to a risk event.

RDF: The Risk-Based Decision-Making Framework (RDF) proceeding, Rulemaking (R.) 20-07-013. This proceeding was closed with its final decision, the Phase 4 Decision (D.) 25-08-032, issued on August 29, 2025.

Risk-Averse Scaling Function: A convex scaling function permitted in Phase 3 of the RDF proceeding that applies greater weight to higher-consequence events compared to lower-consequence ones.

RRUs: Risk Reporting Units (RRUs) are units for proposing, performing, and reporting on risk mitigations that will aggregate as a group of contiguous assets or systems that exhibit high levels of risk. RRUs are intended to provide risk mitigation data at the level of a discrete portion of an overall mitigation program, which will usually be synonymous with 'project' or 'subproject' depending on the IOU's mitigation execution practice. RRUs must have elements in common that must include, but are not limited to, consequence attributes, risk level, line-item costs, BCRs, work units, and time. The requirement of defining RRUs for mitigations was introduced in Phase 4 of the RDF proceeding.

Tail Risk: An analysis that allows for utilities to account for low-probability, high-consequence events in risk modeling. Tail risk analysis ensures that extreme but plausible scenarios are considered in risk exposure and mitigation planning. The requirement of tail risk analysis was introduced in Phase 3 of the RDF proceeding.

Tranches, Tranching: Groups of assets or resources (or risk scenarios) that share similar characteristics, allowing utilities to quantify and compare risk across homogeneous subsets of assets or resources (or risk scenarios). Tranching is the term for the methodology by which the utility defines tranches.

TY 2029 GRC: SCE's Test Year 2029 General Rate Case (GRC) application. The Commission and the utilities refer to GRC applications by the "test year" (TY) on which they base the general rate case estimates and calculations.

Evaluation Scope and Methodology

The 2026 SCE RAMP application consists of the application and associated work papers, which are electronic Excel files and PDF documents obtained from SCE's CPUC Open Proceedings web page for the 2026 RAMP proceeding.[30] Note that SCE submitted its Climate Pilot White Paper as Appendix A to Chapter 2 of its RAMP application, but SPD did not evaluate it as part of the 2026 RAMP evaluation.[31]

The Scoping Memo[32] for SCE's 2026 RAMP proceeding prescribed the scope of issues that formed the basis of SPD's evaluation. Also, RDF documents applicable to this RAMP (Phase 2, 3, and 4 Decisions), including their appended frameworks and guidelines, governed the scope of SPD's evaluation.

SCE's written responses to SPD's 14 data requests further inform SPD's evaluation. A list of SPD's requests and SCE's responses is available on SCE's CPUC Open Proceedings web page for the 2026 RAMP proceeding.

SPD also considered informal comments that parties posted to this proceeding's service list.

SPD used a standard evaluation template to review each risk chapter in SCE's 2026 RAMP application. SPD evaluated each risk chapter addressing the following topics:

- Risk Description
- Risk Bow Tie
- Risk Exposure
- Risk Tranches
- Risk Reporting Units (RRUs)
- Risk Drivers and Frequencies
- Consequences
- Controls and Mitigations

---

[30] SCE's RAMP application and work papers, including its pre-filing white papers (filed under Chapter 2 work papers), as well as data request responses are available on the SCE web page CPUC Open Proceedings under 2026 RAMP (Open Proceedings web page URL: https://www.sce.com/regulatory/regulatory-information/open-proceedings/cpuc-open-proceedings; 2026 RAMP web page URL: https://edisonintl.sharepoint.com/teams/Public/regpublic/Regulatory%20Documents/Forms/RIMS%20Doc%20Set%20View.aspx?id=%2Fteams%2FPublic%2Fregpublic%2FRegulatory%20Documents%2FPD%2FCPUC%2F22361, both accessed June 12, 2026).

[31] In a process separate from SCE's 2026 RAMP evaluation, the Security and Resilience Unit of the Safety Policy Division will evaluate the Climate Pilot White Papers filed by Pacific Gas and Electric (PG&E) in September 2025 and SCE and the Sempra utilities in May 2026 to meet the requirements of RDF Phase 3 D.24-05-064 (pp. 88-92).

[32] Scoping Memo and Ruling for Application Of Southern California Edison Company (U338E) Regarding 2026 Risk Assessment Mitigation Phase, Application (A.) 26-05-018 (Aug. 6, 2026) (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M613/K175/613175609.PDF, accessed Oct. 12, 2026).

- Alternatives Analysis[33]
- BCR Calculations

As part of its RAMP application, SCE reports cost estimates for its risk mitigations. While SPD reviewed these estimates for consistency and verified the correct estimates were used in BCR calculations, it is beyond the scope of this evaluation to verify the reasonableness or accuracy of these estimates. To the extent that SCE's mitigation cost estimates contain errors, those errors impact the utility's BCR calculations, potentially affecting mitigation decisions. Therefore, the utility should substantiate cost estimates in its Test Year 2029 GRC application.

The Scoping Memo guiding SPD's evaluation of SCE's 2026 RAMP application enumerates the following issues for consideration:[34]

1. Whether SCE's Risk Assessment and Mitigation Phase (RAMP) filing is complete and in compliance with previous RAMP-related and governing decisions. This includes, but is not limited to:
    a. Whether SCE identifies and integrates the full set of benefits that are the result of the incurred costs into its benefit cost ratio (BCR) estimates; demonstrates adequate consideration of these costs and benefits when assessing its risk mitigation programs; and calculates and uses its BCR estimates in compliance with the directives of D.22-12-027, D.24-05-064, and D.25-08-032.
    b. Whether SCE's proposed alternative tranching methods for a set of risks (employee and contractor safety, cyber attack, hydro dam failure, seismic, physical security, and public safety risk not attributable to asset failure) are acceptable alternatives to the Commission's best-practice quintile approach to tranching, as set forth in D.24-05-064.
    c. Whether SCE shows the potential CoRE as a probability distribution from which an expected value or tail risk value can be calculated, explaining for each enterprise risk how SCE derived the probability distribution for the potential CoRE, in compliance with the directives of D.25-08-032.
    d. Whether SCE's RAMP filing includes four optimized enterprise portfolios with differing budget scenarios and whether the enterprise portfolios' budget scenarios are based on the baseline cost forecast in compliance with the directives of D.25-08-032.
    e. Whether SCE incorporates overall residual risk reporting in compliance with the directives of D.25-08-032.
    f. Whether SCE developed and provides adequate description of its Risk Reporting Units (RRUs) in compliance with the directives of D.25-08-032.

[33] A utility is required to present in its RAMP application two alternative mitigation plans that it considered for every RAMP risk pursuant to RDF Decisions 14-12-025, 16-08-018, and 18-12-014.

[34] CPUC, Assigned Commissioner's Scoping Memo and Ruling (Application 26-05-018) (Aug. 6, 2026) (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M613/K175/613175609.PDF, accessed Oct. 9, 2026).

   g. Whether SCE provides pre- and post-mitigation values for likelihood of a risk event (LoRE), consequences of a risk event (CoRE), monetized risk value, risk reduction, and benefit-cost ratios for all RRUs that aggregate up to a mitigation program subject to RAMP analysis in compliance with the directives of D.25-08-032.
   h. Whether SCE has reasonably implemented the Environmental and Social Justice Pilot Study in compliance with the directives of D.22-12-027.
2. Whether SCE's RAMP filing adequately describes how SCE uses its risk model and risk analysis in the selection and implementation of its mitigation programs.
3. Whether there are gaps in SCE's RAMP filing in identifying enterprise-level risks and considering mitigation options, including but not limited to:
   a. Whether SCE reasonably assesses and analyzes the cost efficiency of its mitigation programs.
   b. Whether SCE considers and adequately discusses reasonable alternatives to its proposed mitigation plans.
   c. Whether SCE demonstrates the reasonableness of its risk-averse scaling functions and their application.
   d. Whether SCE demonstrates the reasonableness of its tail-risk analysis, including wildfire tail-risk treatment.
4. Whether SCE's analysis is transparent and allows for independent validation of its results.
5. Whether feedback on SCE's RAMP Application has been adequately incorporated into SCE's 2029 Test Year General Rate Case filing.
6. Whether SCE's RAMP Application aligns with or impacts the achievement of any of the nine goals of the Commission's Environmental and Social Justice Action Plan.

Where SPD staff observed deficiencies in SCE's compliance with the RDF guidelines, SPD describes these as findings and, where appropriate, provides corresponding recommendations for improvement.

Key Differences between SCE's 2022 and 2026 RAMP

In addition to the new requirements introduced by the RDF Phase 3 and Phase 4 Decisions (from 2024 and 2025, described above), SCE introduced the following changes in its 2026 RAMP:

- **Asset-Based Approach:** SCE takes an asset-based approach to assessing risk in its 2026 RAMP. In 2022, its RAMP assessed risk based on outcomes (e.g., failure or contact).[35]
- **Improved Wildfire Modeling:** SCE has developed a new Wildfire Integrated Model (WIM) and a climate-informed variant of the model, "WIM (Climate)."[36] SCE reports that these models "combined stochastic tail-risk information consistent with power-law distributions [with] SCE's existing granular, physics-based approach."[37] These models improve on previous variants by better incorporating risk from low-probability, high-consequence events. SCE also expanded and refined data inputs to its wildfire risk model, including community assessments (e.g., evacuation risk).[38]
- **Overhead Equipment Failure:** SCE introduced the risk chapter "Overhead Equipment Failure" (Chapter 5), "reflect[ing] a broader, asset-based approach to assessing and managing overhead system risk."[39] It replaced "Contact with Energized Equipment Risk," which was outcome-focused. For more information on the changes introduced with this new chapter, see SPD Evaluation Report Chapter 2 Overhead Equipment Failure Risk, Table 2-1, "Changes from 2022 RAMP to 2026 RAMP."
- **Public Safety Risk:** SCE introduced "Public Safety Risk Not Attributable to Asset Failure" (Chapter 9), describing risks from contact by third parties with **intact** electrical equipment[40] (e.g., a vehicle hit pole event), formerly covered under "Contact with Energized Equipment Risk" (defined as "human contact with energized equipment…"[41]). In its 2026 RAMP, SCE covered risk from contact by third parties with **failed** electrical equipment (e.g., a wire-down event) in Chapter 5 "Overhead Equipment Failure" and Chapter 6 "Underground Equipment Failure."

---

[35] SCE 2026 RAMP, Section II "Executive Summary," p.3.

[36] SCE 2026 RAMP, Section IV "SCE'S Wildfire Mitigation Strategy," p. 6.

[37] SCE 2026 RAMP, Section VII "Advances in SCE's Risk Modeling," p.16.

[38] SCE 2026 RAMP, Section VII "Advances in SCE's Risk Modeling," p.16.

[39] SCE 2026 RAMP, Chapter 2 "Risk Model and BCR Methodology," p. 17.

[40] SCE 2026 RAMP, Chapter 9 "Public Safety Risk Not Attributable to Asset Failure," Table II-2 "Public Safety Risk not Attributable to Asset Failure Chapter Scope," p. 7.

[41] SCE 2022 RAMP, Chapter 5 "Contact with Energized Equipment," p. 5.

- **The Definition of Control and Mitigation:** SCE has changed how it uses the terms "control" and "mitigation" since 2022. In 2022, "[t]he term 'control' refer[red] to an activity performed prior to or during 2022 to address the risk, and that may continue through the RAMP period […]"; "the term 'mitigation' refer[red] to an activity commencing in 2023 or later...."[42] In 2026, "[t]he term 'control' refers to an activity or program that is already in place prior to the 2029 Test Year and is proposed for continuation […]"; "the term 'mitigation' refers to an activity commencing in 2029 or later...."[43] Thus, in SCE's 2026 RAMP, "mitigation" referred to something that will not be in place for three years, while in its previous RAMP SCE used that term to mean an activity starting in the following year. "Control" in both cases meant an activity already existing at the time of the RAMP filing.

[42] SCE 2022 RAMP, Section I "Executive Summary," p. 3, footnote 7.

[43] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

SCE's RAMP Risk Selection Process

SCE's risk selection process for its 2026 RAMP follows the process described in the Phase 4 RDF Decision.[44] Consistent with the "Risk Assessment" component of the Phase 4 Decision,[45] SCE started its RAMP risk selection process by scoring a set of enterprise risks found in its Enterprise Risk Register (ERR), determining which are "hazard-based" (i.e., risks that could reasonably be expected to have "safety-related consequences")[46] and which have non-zero safety risk values. SCE identified 11 hazard-based risks with non-zero safety risk values in its ERR. The RDF Decision requires SCE to calculate monetized reliability risk and financial risk values for the top 40 percent of those risks with a non-zero safety risk value: 4.4 is 40 percent of 11, so SCE rounded up and calculated those values for the top five enterprise risks.[47] In order of highest to lowest risk value (including safety, reliability, and financial risks) these five risks are: (1) wildfire and PSPS, (2) overhead asset failure, (3) public safety risk not attributable to asset failure, (4) contractor safety, and (5) employee safety.[48] In addition to these top five risks, SCE included five risks in its 2026 RAMP with a non-zero safety risk value. These risks, ranked in order of highest safety risk value to lowest, are: (6) physical security, (7) underground equipment failure, (8) seismic, (9) cyber attack, and (10) hydro asset failure. SCE calculated a non-zero value for the safety risk from battery energy storage systems but doesn't include it as a RAMP risk in 2026 due to its low risk value (less than one).[49]

Per RDF requirements, SCE publicly circulated preliminary information about its RAMP selection process in advance of its pre-filing RAMP workshop to allow stakeholders an opportunity to review its preliminary RAMP risk list.[50]

---

[44] D.25-08-032, Appendix A, Rows 9-12, pp. A-12-A-14.

[45] D.25-08-032, Appendix A, Row 9, p. A-12.

[46] SCE 2026 RAMP, Section IV "Step 1B — Identify Risks for the Enterprise Risk Register," p.11.

[47] SCE's Pre-Filing Workshop Presentation Video, Dec. 18, 2025, slide 14, Gary Cheng presenting, minute 20 to minute 20:22 (to access video, go to SCE's Open Proceedings web page, click on "2026 RAMP," and find the video at the beginning of the roster of files) (https://www.sce.com/regulatory/regulatory-information/open-proceedings/cpuc-open-proceedings, accessed July 13, 2026).

[48] SCE's Pre-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop Presentation, Dec. 18, 2025, slide 14 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-pre-filing-ramp-workshop-slides_dec-2025.pdf, accessed July 10, 2026).

[49] SCE's Pre-Filing Workshop Presentation, slide 14.

[50] Per D.25-08-032, Appendix A, Row 12, p. A-14, the utility is required to provide its preliminary list of RAMP risks at least 14 days in advance of the pre-filing workshop. SCE provided this list to the service lists for the 2020 RDF proceeding and SCE's 2022 RAMP proceeding (R.20-07-013 and A.22-05-013 respectively) on December 4, 2025, 14 days before its pre-filing workshop on December 18, 2025.

Ranked List of Risks

In Table 1 below, SPD presents SCE's list of enterprise risks ranked by risk value, with data on SCE's proposed plan to mitigate each risk.

Of the 11 proposed plans, four appear to increase risk: public safety risk not attributable to asset failure, contractor safety, employee safety, and major physical security. Per SCE's explanation, these increasing risk values are due in part to the risk mitigation plan sustaining risk at current levels rather than allowing it to increase while incorporating increases in costs due to inflation.[51, 52]

[51] "SCE applies an annual inflation rate of 2.3% to all the consequence values, including any benefit-streams associated with mitigations," per SCE 2026 RAMP, Chapter 2 "Risk Model and Benefit-Cost Ratio Methodology," p. 27.

[52] Regarding the apparent post-mitigation increase in risk value for employee safety risk, SCE explained, "existing controls are projected to sustain risk at current levels rather than allow risk to increase. It should not be interpreted as evidence that the programs provide no benefit. Similarly, the increase in post-mitigation consequence values is driven by changes in the underlying consequence modeling assumptions and economic valuation inputs used in the RAMP analysis and does not indicate that the proposed mitigations increase employee risk," per SCE response to Data Request SPD-SCE-2026RAMP-012, Question 1.

Table 1. SCE Enterprise Risks and Proposed Mitigation Plans (Risk Values in $000s)

Rank [53]	Risk[54]	Pre-Mitigation Risk Value	Proposed Plan Risk Reduction Value***	Proposed Percentage Change in Risk***	Proposed Plan BCR (Hybrid Rate)
1*	Wildfire associated with utility operations	$6,980,679[55]	$262,519	-3.8%	11.59[56]
1*	PSPS	$635,376[57]	$39,341	-6.2%	0.23[58]
2*	Overhead equipment failure	$1,447,591[59]	$255,154	-17.6%	1.98[60]
3*	Public safety risk not attributable to asset failure	$275,963[61]	-$18,513	+6.7%	0.64***

[53] SCE's Pre-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop Presentation, Dec. 18, 2025, slide 14 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-pre-filing-ramp-workshop-slides_dec-2025.pdf, accessed July 10, 2026).

[54] Names of risks taken from SCE 2026 RAMP, Section VI "Steo 2B —Selecting Enterprise Risks for RAMP," pp. 16-17.

[55] SCE 2026 RAMP, Chapter 4 "Wildfire and PSPS," Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk ($000s)," p. 22.

[56] SCE 2026 RAMP, Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

[57] SCE 2026 RAMP, Ch. 4, Table I-3 "Summary of Pre- and Post-LoRE Risk Score for PSPS," p. 22.

[58] SCE 2026 RAMP, Ch. 4, Table XIII-61 "Proposed Plan Programmatic PSPS Estimated Spend ($000s) and Benefit-Cost Ratios," p. 120.

[59] SCE 2026 RAMP, Chapter 5 "Overhead Equipment Failure," Table VI-16 "Summary of Pre- and Post- LORE and CORE Risk Scores," p. 37.

[60] SCE 2026 RAMP, Ch. 5, Table VI-17 "Proposed Plan Programmatic Estimated Spend and Benefit-Cost Ratios," p. 37.

[61] SCE 2026 RAMP, Ch. 9, Table VI-8 "Proposed Plan Pre- and Post-Mitigation LoRE, CoRE and Risk Scores," p. 31.

Rank [53]	Risk[54]	Pre-Mitigation Risk Value	Proposed Plan Risk Reduction Value***	Proposed Percentage Change in Risk***	Proposed Plan BCR (Hybrid Rate)
4*	Contractor safety	$84,233[62]	-$8,021	+9.5%	1.83[63]
5*	Employee safety	$52,839[64]	-$5,031	+9.5%	0.34[65]
6**	Major physical security	$159,810[66]	-$6,161	+3.9%	0.15[67]
7**	Underground equipment failure	$1,037,336[68]	$47,863	-4.6%	2.27[69]
8**	Seismic	$919,842[70]	$197,499	-21.5%	27.73[71]
9**	Cyber attack	$1,722,434[72]	$64,008	-3.7%	4.44[73]

[62] SCE 2026 RAMP, Chapter 8 "Contractor Safety," Table VI-14 "Pre and Post LoRE, CoRE and Risk Scores for Proposed Plan," p. 35.

[63] SCE 2026 RAMP, Ch. 8, Table VI-15 "BCR Values for Proposed Controls," p. 35.

[64] SCE 2026 RAMP, Chapter 7 "Employee Safety," Table VII-13 "Pre- and Post- LoRE, CoRE and Risk Scores," p. 41.

[65] SCE 2026 RAMP, Ch. 7, Table VII-14 "BCR Values for Proposed Plan Controls," p. 42.

[66] SCE 2026 RAMP, Chapter 12 "Physical Security," Table VII-10 "Proposed Plan Pre- and Post-LoRE, CoRE Risk Scores," p. 45.

[67] SCE 2026 RAMP, Ch. 12, Table VII-11 "BCR Values for Proposed Plan Controls," p. 46.

[68] SCE 2026 RAMP, Chapter 6 "Underground Equipment Failure," Table VI-16 "Summary of Proposed Plan Pre and Post LORE and CORE Risk Scores," p. 45.

[69] SCE 2026 RAMP, Ch. 6, Table VI-17 "Proposed Plan Programmatic Estimated Spend and Benefit Cost Ratios," p. 45.

[70] SCE 2026 RAMP, Chapter 11 "Seismic," Table VI-6 "Seismic Proposed Plan and Alternative Plans Summary of Pre and Post LoRE and CoRE Risk Scores," p. 33.

[71] SCE 2026 RAMP, Ch. 11, Table VI-9 "BCR Values for Proposed Controls," p. 35.

[72] SCE 2026 RAMP, Chapter 10 "Cyber Attack," Table VI-5 "Cyber Attack Proposed Plan and Alternative Plans Summary of Pre and Post LoRE and CoRE Risk Scores," p. 33.

[73] SCE 2026 RAMP, Ch. 10, Table VI-8 "Proposed Plan Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 35.

Rank [53]	Risk[54]	Pre-Mitigation Risk Value	Proposed Plan Risk Reduction Value***	Proposed Percentage Change in Risk***	Proposed Plan BCR (Hybrid Rate)
10**	Hydro dam safety	$1,890[74]	$249	-13.2%	0.0661[75]

* Ranking by total risk value combing safety, reliability, financial risk values.

** Ranking by safety risk value.

*** Calculated by SPD.

[74] SCE 2026 RAMP, Chapter 13 "Hydro Asset Failure," Table VI-6 "Hydro Asset Failure Proposed Plan and Alternative Plans Summary of Pre and Post LoRE and CoRE Risk Scores Nominal $000s," p. 43.

[75] SCE 2026 RAMP, Ch. 13, Table VI-10 "Proposed Plan, Control Program Estimated," p. 47.

Evaluation of SCE's Risk Model and Benefit-Cost Ratio Methodology

This chapter presents Safety Policy Division's (SPD's) summary and discussion of Southern California Edison Company's (SCE's) Risk Assessment and Mitigation Phase (RAMP) chapter titled "Risk Model and Benefit-Cost Ratio Methodology." In this chapter, SCE presents its general approach to the Risk-Based Decision-Making Framework (RDF) requirements as adopted in the RDF Phase 4 Decision.[76, 77] SPD discusses different aspects of SCE's risk model and benefit-cost ratio methodology further below in Chapter 1 "Wildfire and PSPS Risk." This chapter also examines the results of SCE's portfolio optimization.

The RDF Phase 2 Decision requires the use of cost-benefit ratios (CBRs) in RAMP and General Rate Case (GRC) filings, defined as a value "calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate"[78] and, because the ratio is expressed as benefit/cost, the RDF Phase 4 Decision updated the term from cost-benefit ratios to benefit-cost ratios (BCRs).[79]

Regarding BCR calculation methods, the California Public Utilities Commission (Commission or CPUC) has not established a standard method for calculating a BCR outside of the general guidance in the RDF decisions. The most current CPUC guidance on calculating BCRs in the RDF Phase 4 Decision does not, for example, explicitly discuss how to account for operations and maintenance (O&M) savings or expenses in a BCR calculation.[80]

The general guidance provided by the RDF Phase 4 Decision provides the basic formula for calculating a BCR,[81] and guidelines for the monetization of risk consequences,[82] use of risk scaling to signify aversion to

---

[76] Phase 4 Decision with Appendices (D.25-08-032 of Aug. 29, 2025).
(https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=578198350, accessed May 27, 2026).
This decision closed Rulemaking (R.) 20-07-013.

[77] Phase 4 Decision Appendix A, Risk-Based Decision-Making Framework: Regarding Required Elements for Risk and Mitigation Analysis in the Risk Assessment [and] Mitigation Phase (RAMP) and General Rate Case (GRC) Applications
(https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M578/K147/578147121.pdf, accessed Sept. 22, 2026). Appendix A provides the utility requirements for RAMP filings.

[78] See Appendix A of the RDF Phase 2 Decision (D.22-12-027) for a description of the RDF's cost-benefit approach, in particular see Definitions, p. A-3; Rows 1-7, pp. A-9-A-10
(https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043720.PDF, accessed May 27, 2026).

[79] D.25-08-032, Appendix A, Definitions, p. A-3.

[80] D.25-08-032, Appendix A, Rows 1-7, pp. A-9-A-10.

[81] "Calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate," per D.25-08-032, Appendix A, Definitions, p. A-3; Rows 1-7 present the RDF's six principles of a "Cost-Benefit Approach."

[82] D.25-08-032, Appendix A, Row 6, p. A-10.

high consequence risk events,[83] risk tranching,[84] and—newly introduced in this 2026 RAMP— the construction of optimized portfolios at various budget scenarios.[85]

Below, SPD discusses SCE's approach to the RDF requirements.

Monetized Values of the Safety, Reliability, and Financial Attributes

Per RDF requirements described in "Cost-Benefit Approach Principle 5 – Monetized Levels of Attributes"[86] and "Risk Assessment," SCE computed a monetized risk value using the safety, reliability, and financial attributes.[87] Table 1 describes how SCE calculates these values.

Table 2. Monetized Values of Safety, Reliability, and Financial Attributes (in 2025 dollars)[88]

Attribute	Sub-Attribute	Monetized Value
Safety	Potential serious injuries or fatalities (PSIFs); serious injuries, fatalities	$1.74 million per PSIF; $4.35 million per serious injury; $17.4 per fatality[89]
Reliability	Customer minute interrupted (CMI)	$5.63 per CMI (system-wide blended)[90]
Financial	Financial cost (dollars)	$1[91]

[83] D.25-08-032, Appendix A, Row 7, p. A-10.

[84] D.25-08-032, Appendix A, Row 14, pp. A-15-A-16.

[85] D.25-08-032, Appendix A, Definitions, p. A-6; Rows 25.1-25.2, pp. A-19-A-20.

[86] D.25-08-032, Appendix A, Row 6, p. A-10.

[87] D.25-08-032, Appendix A, Row 9, p. A-12.

[88] SCE 2026 RAMP, Chapter 2 "Risk Model and Benefit-Cost Ratio Methodology," pp. 5-7.

[89] SCE 2026 RAMP, Ch. 2, p. 5.

[90] SCE 2026 RAMP, Ch. 2, p. 6.

[91] SCE 2026 RAMP, Ch. 2, p. 7.

SCE monetized safety consequences using the United States (U.S.) Department of Transportation's Value of Statistical Life (VSL). For its 2026 RAMP, SCE began with a base-year (2025) VSL of $14.2 million.[92, 93] Then, SCE adjusted this value using a California-specific price index and real income factors. These adjustments resulted in a California-adjusted VSL of $17.4 million (2025 dollars).[94] SCE applied this value to represent the monetized consequence of a single fatality. Additionally, SCE valued each serious injury as one-quarter of a fatality.[95] For employee and contractor safety risks, SCE also valued each potential serious injury or fatality (PSIF) as one-tenth of a fatality.[96]

SCE monetized reliability consequences using the most recent version of the Lawrence Berkeley National Laboratory (LBNL) Interruption Cost Estimate (ICE) Calculator (Version 2.2, released on February 19, 2026).[97] The ICE Calculator converts a customer minute interrupted (CMI) into monetized values by accounting for each of two customer classes, residential and non-residential, and outage duration.

SCE applied assumptions specific to SCE's operating environment to produce system-wide estimated values of service: $5.63 per CMI by blending residential and non-residential values, $0.09 per CMI for residential customers, and $41.62 per CMI for non-residential customers (all values in 2025 dollars).[98] SCE applied these values in one of two ways. First, for risks where SCE cannot meaningfully tie mitigations to a specific geography (e.g., risk mitigations for cyber attack), SCE estimated reliability consequences using the system-wide blended value of $5.63 per CMI.[99] Second, for risks where SCE can meaningfully tie mitigations to a specific geography (e.g., risk mitigations for wildfire), SCE estimated location-specific reliability consequences using the system-wide residential and non-residential CMI values of $0.09 and $41.62, respectively, weighted by the customer mix at each mitigation location.[100]

---

[92] U.S. Department of Transportation, Departmental Guidance on Valuation of a Statistical Life in Economic Analysis (Effective Date: March 20, 2026) (https://www.transportation.gov/office-policy/transportation-policy/revised-departmental-guidance-on-valuation-of-a-statistical-life-in-economic-analysis, accessed June 23, 2026).

[93] SCE 2026 RAMP, Ch. 2, p. 5.

[94] SCE 2026 RAMP, Ch. 2, p. 5.

[95] SCE 2026 RAMP, Ch. 2, p. 5.

[96] SCE 2026 RAMP, Ch. 2, p. 5.

[97] The Interruption Cost Estimate (ICE) Calculator (https://icecalculator.com/, accessed Sept. 23, 2026).

[98] SCE 2026 RAMP, Ch. 2, p. 6.

[99] SCE 2026 RAMP, Ch. 2, p. 6.

[100] SCE 2026 RAMP, Ch. 2, p. 6.

SCE described the methods it used to estimate financial consequences for the relevant risk in each RAMP risk chapter. SCE expresses financial costs in dollars.[101] SCE notes that these costs may include costs associated with property damage and equipment repair or replacement.[102]

Observations and Findings

SPD observes that ICE Calculator Version 2.0 (ICE 2.0) and later versions include several key differences from ICE Calculator Version 1.0 (ICE 1.0). ICE 1.0 allowed three standard customer categories: residential, small non-residential, and medium/large non-residential, while ICE 2.0 and later versions allow only two customer categories: residential and non-residential.[103] Additionally, ICE 1.0 used customer interruption cost information from surveys conducted in 1989-2012, while ICE 2.0 and later use customer interruption cost information from surveys conducted beginning in 2022.[104]

In a comparison of ICE 1.0 and ICE 2.0 conducted by Lawrence Berkeley National Laboratory (LBNL), results showed that residential power interruption costs estimated using ICE 2.0 were lower for interruptions lasting less than 90 minutes but higher for longer interruptions.[105] For non-residential, ICE 2.0 and 1.0 estimated costs were similar for short interruptions, but ICE 2.0 estimated costs were much lower for interruptions lasting five or more hours.[106] For interruptions lasting 10 or more hours, ICE 2.0 estimated costs were as much as 50-75 percent lower than ICE 1.0 estimated costs.[107]

---

[101] SCE 2026 RAMP, Ch. 2, p. 7.

[102] SCE 2026 RAMP, Ch. 2, p. 4.

[103] ICE Calculator 1.0 vs. 2.0: A Comparison of Estimated Customer Power Interruption Costs (undated, file name dated May 2025), Table 1 "Summary of differences between ICE 1.0 and 2.0," PDF p. 1 (https://eta-publications.lbl.gov/sites/default/files/2025-06/ice_2.0_vs_1.0_comparison_may2025.pdf, accessed Sept. 23, 2026).

[104] ICE Calculator 1.0 vs. 2.0: A Comparison of Estimated Customer Power Interruption Costs (undated, file name dated May 2025), Table 1 "Summary of differences between ICE 1.0 and 2.0," PDF p. 1 (https://eta-publications.lbl.gov/sites/default/files/2025-06/ice_2.0_vs_1.0_comparison_may2025.pdf, accessed Sept. 25, 2026).

[105] ICE Calculator 1.0 vs. 2.0: A Comparison of Estimated Customer Power Interruption Costs (undated, file name dated May 2025), PDF p. 4 (https://eta-publications.lbl.gov/sites/default/files/2025-06/ice_2.0_vs_1.0_comparison_may2025.pdf, accessed Sept. 25, 2026).

[106] ICE Calculator 1.0 vs. 2.0: A Comparison of Estimated Customer Power Interruption Costs (undated, file name dated May 2025), Figure 2 "Small non-residential customer interruption costs estimated using ICE 1.0 and 2.0" and Figure 3 "Medium/large non-residential customer interruption costs estimated using ICE 1.0 and 2.0," PDF p. 3 (https://eta-publications.lbl.gov/sites/default/files/2025-06/ice_2.0_vs_1.0_comparison_may2025.pdf, accessed Sept. 25, 2026).

[107] ICE Calculator 1.0 vs. 2.0: A Comparison of Estimated Customer Power Interruption Costs (undated, file name dated May 2025), PDF p. 4 (https://eta-publications.lbl.gov/sites/default/files/2025-06/ice_2.0_vs_1.0_comparison_may2025.pdf, accessed Sept. 25, 2026).

In a separate comparison of ICE 2.0 and 2.2 also conducted by LBNL, the results showed residential power interruption costs estimated using ICE 2.2 were 2-4 percent lower.[108] For non-residential, the power interruption costs estimated by ICE 2.2 were 15 percent lower for momentary interruptions, 18-19 percent higher for interruptions lasting two and eight hours, and 4 percent higher for 24-hour interruptions.[109] These increases in estimated costs observed in the comparison of ICE 2.0 and ICE 2.2 partially offset the decreases observed in the comparison between ICE 1.0 and ICE 2.0. Despite these partial offsets, the combined comparison results show that interruption costs estimated using ICE 2.2 are generally lower than those estimated using ICE 1.0.

In San Diego Gas & Electric Company's (SDG&E's) 2025 RAMP application, SDG&E used ICE 1.0 to estimate the monetized value per CMI.[110] SDG&E estimated a value per CMI for each of three customer categories (i.e., residential, small commercial and industrial, and medium and large commercial and industrial)[111] and a blended system-wide value. SDG&E's residential and blended system-wide interruption cost per CMI was $0.05 and $3.67, respectively.[112, 113] As mentioned previously, SCE used ICE 2.2 to estimate a system-wide value per CMI for two customer categories, $0.09 for residential and $41.62 for non-residential, and SCE calculated a blended system-wide value per CMI of $5.63.[114] SCE's residential value per CMI is about 1.8 times and blended system-wide value per CMI is about 1.5 times that of SDG&E's in 2025. Although the LBNL study indicates that new ICE models generally produce lower values than ICE 1.0, differences in customer experience across service territories and in the mix of customer classes between SDG&E and SCE are likely why SCE values are higher. These differences illustrate that values of $/CMI are dependent not only on the ICE version but on the service territory data provided to the ICE model.

In addition, SPD observes that SCE generally follows the RDF guidelines for monetization, adding a refinement to estimate reliability benefits for location-specific mitigations (e.g., wildfire risk mitigations) by

---

[108] A Preview of Updates to the Interruption Cost Estimate (ICE) Calculator: Key Differences Between Version 2.0 and 2.2 (undated, file name dated March 2026), PDF p. 4 (https://eta-publications.lbl.gov/sites/default/files/2026-03/ice_2.0_vs_2.2_comparison.pdf, accessed Sept. 25, 2026).

[109] A Preview of Updates to the Interruption Cost Estimate (ICE) Calculator: Key Differences Between Version 2.0 and 2.2 (undated, file name dated March 2026), PDF p. 4 (https://eta-publications.lbl.gov/sites/default/files/2026-03/ice_2.0_vs_2.2_comparison.pdf, accessed Sept. 25, 2026).

[110] Sempra 2025 RAMP Application, Chapter RAMP-1 "Overiew," pp. 8-9 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/2025-sempra-ramp-application.pdf, accessed Sept. 23, 2026).

[111] Sempra 2025 RAMP Application, Chapter RAMP-3 "Risk Quantification Framework," Table 7 "SDG&E Monetized CMI," p. 11.

[112] Sempra 2025 RAMP Application, Chapter RAMP-3 "Risk Quantification Framework," Table 7 "SDG&E Monetized CMI," p. 11.

[113] Sempra 2025 RAMP Application, Chapter RAMP-3 "Risk Quantification Framework," Table 7 "SDG&E Monetized CMI," p. 11.

[114] SCE 2026 RAMP, Ch. 2, p. 6.

blending residential and non-residential CMI values, weighted by the mix of these customer categories at each location. However, SCE calculates the CMI values in any case based on the system-wide CMI value, rather than for the location type where it is planning a mitigation. The values could be quite different for customers in high-fire threat areas than for urban customers, who are combined together in system-wide numbers. SCE could calculate a more accurate CMI value for each customer category by using customer input data taken specifically from the area where SCE is planning a mitigation. For example, SCE could determine more precise CMI values for residential and non-residential categories in the area where it is planning a wildfire mitigation (i.e., customer category values specific to SCE's High Fire Risk Area [HFRA]).

Calculation of Benefit-Cost Ratios

Discount Rate Scenarios

Per RDF requirements,[115] SCE calculated and presents BCRs based on three discount rate scenarios: the societal discount rate scenario, weighted-average cost of capital (WACC) discount rate scenario, and hybrid discount rate scenario (see Table 2).

Table 3. Discount Rate Scenarios[116]

BCR Component	Societal	WACC	Hybrid
Safety Benefits	2%	7.59%	6.1%
Reliability Benefits	2%	7.59%	6.1%
Financial Benefits	2%	7.59%	7.59%
Costs	2%	7.59%	7.59%

For the societal discount rate scenario, SCE applied a 2 percent discount rate, based on the U.S Office of Management and Budget (OMB) Circular A-4, to all components in the numerator and denominator of a BCR calculation.[117] For the WACC discount rate scenario, SCE applied a 7.59 percent discount rate to all components of a BCR calculation. The 7.59 percent is SCE's authorized rate of return for 2026-2028, approved in CPUC Decision (D.) 25-12-043 concerning cost of capital for the large investor-owned

[115] D.25-08-032, Appendix A, Row 25, p. A-19.

[116] SCE 2026 RAMP, Ch. 2, Table VII-2 "Discount Rate Scenarios Summarizes the Three Different Discount Rate Scenarios and the Rates Used," p. 27.

[117] SCE 2026 RAMP, Ch. 2, p. 26.

utilities.[118, 119] For the hybrid discount rate scenario, SCE discounted safety and reliability components of the numerator using a formula specified in the RDF Phase 3 Decision,[120] which resulted in a discount rate of 6.1 percent for safety and reliability benefits.[121] SCE discounted the financial component of the numerator and all components of the denominator using its most recent WACC rate of 7.59 percent. SCE states that it generally references the hybrid discount rate scenario when describing its "scope selection process."[122]

Treatment of O&M Savings and No-Build Baseline in Calculating BCRs

SCE included the incremental O&M costs and avoided O&M costs, also called O&M savings, in the denominator of its BCR calculations. As noted above, the most current guidance from the CPUC on calculating BCRs in the RDF Phase 4 Decision does not explicitly discuss how to account for operations and maintenance (O&M) cost or savings in a BCR calculation.

In its RAMP application, SCE states that "all ... BCRs [for grid hardening risk mitigations] are calculated relative to a 'no-build baseline.'"[123] SPD discusses SCE's application of a no-build baseline in BCR calculations further in Chapter 1 "Wildfire and PSPS Risk."

Observations and Findings

The question of how to account for O&M costs or savings in a BCR calculation was raised on April 10, 2026, when the CPUC published a scoping ruling and memo in response to an IOU joint application regarding BCR methods under the SB 884 Program, including a white paper authored by SPD staff proposing an approach to BCR calculations as an attachment.[124] This staff white paper proposes a BCR calculation incorporating only incremental benefits or costs (those that occur on top of the baseline benefits

---

[118] SCE 2026 RAMP, Ch. 2, p. 26.

[119] Decision Addressing Test Year 2026 Cost of Capital for Pacific Gas and Electric Company, Southern California Gas Company, Southern California Edison Company, and San Diego Gas & Electric Company (D.25-12-043 of Dec. 22, 2025), p. 2 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M591/K833/591833054.PDF, accessed Sept. 23, 2026).

[120] D.24-05-064, pp. 103-104. Phase 3 Decision with Appendices (D.24-05-064 of June 6, 2024), pp. 103-104 (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=533099839, accessed May 27, 2026).

[121] SCE 2026 RAMP, Ch. 2, p. 26.

[122] SCE 2026 RAMP, Ch. 2, p. 27.

[123] SCE 2026 RAMP, Ch. 2, p. 28.

[124] Assigned Commissioner's Scoping Memo and Ruling and Attachments for Application (A.) 26-02-005 (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=604545275, accessed Sept. 1, 2026). See also the docket for A.26-02-005 (https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:A2602005, accessed Sept. 1, 2026).

or costs)[125] and treats O&M costs and O&M benefits (i.e., O&M savings) separately, incorporating incremental O&M costs in the denominator and incremental O&M savings in the numerator of the BCR formula (Method 3,[126] or "Disaggregated Formulation"), depicted below.[127]

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

Figure 1. Disaggregated Formulation (SPD's Recommended Method for Calculating BCRs).[128]

Treating O&M savings as a benefit in the numerator is consistent with how various public agencies and utilities (e.g., U.S. Department of Transportation, Joint Utilities of New York) treat O&M savings.[129]

SCE's approach contrasts with this method. In SPD's staff white paper, SPD describes a method (Method 1,[130] or "Cost-Basis Formulation") that represents SCE's approach to BCR calculations, as "demonstrat[ing] mathematical instability under high O&M Savings conditions," where the denominator can resolve to zero or a negative number.[131] In the SCE method, the combination of O&M costs and savings produces a net O&M value, which is then subtracted from capital costs in the denominator. [132] The Cost-Basis Formulation is described below.

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

Figure 2. Cost-Basis Formulation (SCE's Method for Calculating BCRs).[133]

---

[125] Staff White Paper on Benefit-Cost Ratio Methodology (April 10, 2026) (SPD Staff BCR White Paper), p. 16 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K545/604545276.PDF, accessed Sept. 1, 2026). SPD references this white paper for illustrative purposes only. It is not an authoritative source for BCR requirements for utility RAMP applications.

[126] SPD Staff BCR White Paper, Table 2 "Comparative BCR across three methods and across six illustrative examples," p. 25.

[127] SPD Staff BCR White Paper, p. 20.

[128] SPD Staff BCR White Paper, p. 20.

[129] SPD Staff BCR White Paper, pp. 6-7.

[130] SPD Staff BCR White Paper, Table 2 "Comparative BCR across three methods and across six illustrative examples," p. 25.

[131] SPD Staff BCR White Paper, p. 26.

[132] SPD Staff BCR White Paper, p. 19.

[133] SPD Staff BCR White Paper, p. 19.

In this BCR formula, when O&M savings are more than or equal to the sum of capital and O&M costs, the denominator becomes negative or zero, resulting in a negative or undefined BCR value. A utility can avoid this problem by using a BCR formula such as the Disaggregated Formulation that treats O&M savings as a benefit in the numerator, while maintaining O&M costs as a cost in the denominator, thereby "avoid[ing] negative and zero denominators, and consequently, mathematically undefined BCR results," per SPD's staff white paper.[134]

Additionally, SPD's staff white paper notes the issue that whether the BCR calculation treats O&M savings as a benefit in the numerator or netted against costs in the denominator can alter the BCR value, affecting project prioritization, especially under constrained budgets.[135] Chapter 1 "Wildfire and PSPS Risk" discusses potential problems caused by placing O&M savings in the denominator of BCR calculation.

Risk-Averse Scaling Function

Per RDF requirements,[136] SCE applied a risk-averse scaling function. According to SCE, the purpose of this function is "to translate safety and financial consequences into risk-adjusted attribute levels that account for the asymmetric nature of utility risk exposure."[137] SCE indicates that this "asymmetry" may be seen in "extreme and adverse outcomes (e.g., low-probability, high-consequence events)" that "can result in catastrophic outcomes … not captured in expected-value calculations."[138]

SCE applied the risk-averse function only to the safety and financial consequences of wildfire risk and only when consequence levels exceed a pre-defined threshold. [139] SCE asserts that it applied the risk-averse scaling function "***solely as a sensitivity analysis***," and this sensitivity "***does not*** impact the development of mitigation portfolio construction" or BCR calculations."[140] SCE adds that all "baseline risk estimates and resulting BCR calculations presented in this 2026 RAMP are based on a risk-neutral view."[141]

SCE's threshold for safety consequence is one fatality, and the threshold for financial consequence is $500 million.[142] SCE applied the same risk-averse scaling factor that Sempra applied in its 2025 RAMP

---

[134] SPD Staff BCR White Paper, pp. 26-27.

[135] SPD Staff BCR White Paper, p. 6.

[136] D.25-08-032, Appendix A, Row 7, p. A-10.

[137] SCE 2026 RAMP, Ch. 2, p. 8.

[138] SCE 2026 RAMP, Ch. 2, p. 8.

[139] SCE 2026 RAMP, Ch. 2, p. 8.

[140] SCE 2026 RAMP, Ch. 2, p. 8.

[141] SCE 2026 RAMP, Ch. 2, p. 8.

[142] SCE 2026 RAMP, Ch. 2, p. 9.

application, beyond the safety and financial thresholds, consisting of $\alpha = 1.47$.[143, 144] For example, when the financial consequence exceeded $500 million, SCE used the function depicted in Figure 3 to calculate a risk-averse value.[145]

As an illustration of this risk scaling function, with $\alpha = 1.47$ and a financial threshold of $500 million, a forecasted consequence of $1 billion becomes a risk-averse value of $1.385 billion, 38.5 percent higher than the unscaled value. Because the function is a power law, the adjustment grows with the size of the consequence: a $2 billion consequence becomes $3.84 billion, an increase of 92 percent."

$$Risk\ Averse\ Value\ (Financial) = \left(\frac{x}{Financial\ Threshold}\right)^{\alpha} * (Financial\ Threshold)$$

$$\text{where } x = natural\ unit\ consequences\ from\ the\ consequence\ model$$

Figure 3. SCE's Risk Averse Function.[146]

The impact of SCE's risk-averse scaling function is examined more closely in relevant RAMP risk chapters.

Observations and Findings

As noted above, SCE states that its risk-averse scaling function is intended to account for "utility risk exposure." In other words, the risk-averse scaling function reflects SCE's, not ratepayers,' risk attitude. Although the Commission has not determined a standard method to apply risk scaling, including whose attitude risk scaling should reflect, SPD takes the position that risk scaling should to some extent reflect ratepayers' risk attitude, not only the utility's.

Also, SCE does not present its risk neutral values for comparison in instances where it applies risk-averse scaling.

Alternative Tranching Methods

The RDF requirements, under section "Definition of Risk Events and Tranches," identify the quintile approach as the "best practice for determining the homogeneity of risk profiles in reporting [t]ranches."[147]

---

[143] "SoCalGas and SDG&E adopted the average of [implied risk aversion coefficients of 1.34 for natural catastrophic events and 1.6 for North American pipeline standards], resulting in a risk scaling factor α of 1.47" per Sempra 2025 RAMP Application, Chapter RAMP-3 "Risk Quantification Framework," p. 25.

[144] SCE 2026 RAMP, Ch. 2, p. 10.

[145] SCE RAMP-2 Risk Model and BCR Methodology, p. 10.

[146] SCE 2026 RAMP, Ch. 2, p. 10.

[147] D.25-08-032, Appendix A, Row 14, pp. A-15-A-16.

Using the quintile approach, a utility subdivides the group of assets or the system associated with a risk event into 25 tranches based on quintiles of probability values—likelihood of a risk event (LoRE)—and quintiles of estimated consequence values in dollars—consequence of a risk event (CoRE). Per the RDF requirements, a utility may use an alternative approach to determine tranches, but, if doing so, must submit a white paper describing its preferred method for determining tranches to SPD before its pre-filing RAMP workshop.[148]

As noted above, SCE deviated from the default quintile tranching method in its 2026 RAMP, submitting prior to its pre-filing RAMP workshop a white paper proposing alternative tranching methods for some RAMP risks, namely employee and contractor safety, cyber attack, hydro dam failure, seismic, physical security, and public safety risk not attributable to asset failure.[149] According to SCE, "[r]easons for needing to deviate from the Quintile Approach differed by risk but generally revolved around the nature of how the risk is managed, the availability of data, or other relevant factors."[150] SCE applied the quintile tranching method to its other risks.

SPD examines SCE's specific alternative tranching methods more closely in each relevant RAMP risk chapter.

Portfolio Optimization

Per the RDF requirements,[151] SCE presents four optimized enterprise portfolios based on budget scenarios of 85 percent, 90 percent, 95 percent, and 100 percent of the baseline cost forecast. The RDF requirements indicate that utilities may also construct a set of optimized risk mitigation portfolios:[152] thus SCE also presents a set of four optimized risk mitigation portfolios for each RAMP risk. SPD discusses SCE's portfolio optimization results below.

All portfolio mitigation results are only presented in a work paper.[153]

---

[148] D.25-08-032, Appendix A, Row 14, pp. A-15-A-16.

[149] SCE submitted "SCE 2026 RAMP Tranching White Paper" November 3, 2025; SCE submitted the "Chapter 2 Risk Model and BRC [sic] Methodology Tranching Whitepaper," indicating updates to its approach to tranching for 2026, May 27, 2026.

[150] SCE 2026 RAMP Tranching White Paper, p. 2.

[151] D.25-08-032, Appendix A, Row 25.1, p. A-19.

[152] D.25-08-032, Appendix A, Row 25.2, p. A-20.

[153] SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet.

Enterprise-Wide Optimization

SCE reports that, for each optimized enterprise portfolio, it first excludes compliance-driven programs and their associated costs from the estimated budget scenario, then sorts the controls and mitigations by BCR, which SCE calculates at either the tranche or risk reporting unit (RRU) level.[154] SCE then runs an optimization algorithm that selects activities sequentially in descending order by BCRs until it reaches the applicable budget constraint.[155] SCE does not subject compliance-driven programs (referred to as 'must take' programs in the work paper) to selection based on BCR, as they are required expenditures.[156] Table 3 summarizes SCE's enterprise-wide optimization results for each budget scenario.

Table 4. Enterprise-Wide Optimization Results ($ in Billions)

Component	85%	90%	95%	100%
Total Benefits (Net Present Value)[157]	$58.94	$59.56	$59.17	$59.18
Total Spend (Net Present Value)[158]	$8.50	$9.00	$9.50	$10.00
Enterprise-Wide Portfolio BCR[159]	6.93	6.61	6.23	5.92

The enterprise-wide portfolio BCRs are lower as the budget increases, indicating that proposed mitigations with relatively low BCRs are likely to be included in higher budget scenarios. Additionally, although total benefits are very close across budget scenarios, the 90 percent budget scenario yields the highest total benefits (in net present value [NPV]).

Table 4 summarizes SCE's enterprise-wide optimization results for each budget scenario excluding compliance-driven programs from the calculations.

---

[154] SCE 2026 RAMP, Ch. 2, p. 29.

[155] SCE 2026 RAMP, Ch. 2, p. 29.

[156] SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet, tab "Optimization Results Summary".

[157] SPD calculations with the formula NPV Benefits = NPV Spend x BCR, rounded to the hundredths place, using numbers from SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet, tab "EnterpriseOpt," columns R-V and rows 3-4.

[158] SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet, tab "EnterpriseOpt."

[159] SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet, tab "EnterpriseOpt."

Table 5. Optimization Results Excluding Compliance-Driven Programs ($ in Billions)[160]

Component	85%	90%	95%	100%
Benefits (NPV)	$53.97	$54.59	$54.21	$54.21
Spend (NPV)	$4.91	$5.41	$5.91	$6.41
Portfolio BCR	10.98	10.08	9.16	8.45

After excluding compliance-driven programs, the portfolio BCRs remain lower as the budget increases, and the 90 percent budget scenario still yields the highest benefits.

Risk-Specific Optimization

As noted above, SCE presents four optimized risk mitigation portfolios for each risk in its 2026 RAMP application. SCE changes its estimated spend for each specific mitigation program based on each budget scenario, so that, for example, under the 85 percent budget scenario, SCE applies the 85 percent constraint to the estimated mitigation program spend associated with each RAMP risk.[161] To further illustrate using the case of the wildfire mitigation program, the 100 percent budget scenario includes the full estimated wildfire spend of about $3,666 million, while the 95 percent budget scenario is 95 percent of that, about $3,483 million, and so forth for each scenario, for each program.[162]

Then, as with the enterprise-wide optimization process, SCE runs an optimization algorithm that selects activities, in this case at the tranche or RRU-level, in descending order by BCRs until it reaches the applicable budget constraint.[163] As with the enterprise-wide optimization, SCE does not subject compliance-driven programs to selection based on BCR, as they are required expenditures. Table 5 summarizes SCE's risk-specific optimization results for each budget scenario.

[160] SPD calculations, adding up the NPV Spend and Benefits for all programs excluding compliance-driven programs, and dividing Benefits by Spend to get BCRs, using numbers from SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet, tab "EnterpriseOpt," selecting programs based on the presence or absence of "Compliance" in column I.

[161] SCE 2026 RAMP, Ch. 2, p. 35.

[162] SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet, tab "Wildfire."

[163] SCE 2026 RAMP, Ch. 2, p. 31.

Table 6. Risk-Specific Optimization Results ($ in Billions)[164]

Component	85%	90%	95%	100%
Total Benefits (NPV)	$59.15	$59.98	$60.59	$59.18
Total Spend (NPV)	$8.50	$9.00	$9.50	$10.00
Risk-Specific Portfolio Overall BCR	6.96	6.66	6.37	5.92

With SCE's risk-specific optimization, the 95 percent budget scenario yields the highest NPV benefits, while the previously discussed enterprise-wide approach has the highest benefits for the 90 percent scenario.

Mitigation Groups

Per the RDF requirements, the utility must account for interrelationships, such as "mutual exclusivity, synergies, and diminishing returns," between mitigations in each optimized risk mitigation portfolio.[165] To capture and calculate synergies and diminishing returns, the utility can create a mitigation group, which is a combination of "two or more mitigations to address risk on a given asset or system."[166] The utility must justify the structure of mitigation groups, per RDF requirements.[167]

SCE began forming mitigation groups by first identifying candidate mitigations by reviewing its mitigation scoping plans for the next GRC cycle, focusing on groups of mitigations that it could apply to the same RRU, such as wildfire system hardening, vegetation management, and inspections it is planning for one RRU over the next GRC cycle.[168] Then, to evaluate how the mitigations interrelate, SCE selected and calculated the impact of mitigations in this order: "1) Permanent mitigations which materially change the underlying risk baseline; 2) Mitigations that mitigate the likelihood of risk events; and 3) Mitigations with longer useful lives."[169]

Observations and Findings

As mentioned previously, the benefits (NPV) in SCE's optimized portfolios based on budget scenarios of 85 percent, 90 percent, 95 percent, and 100 percent are almost the same. If SCE proceeds with these same

---

[164] SPD calculations based on numbers from each risk tab in SCE 2026 RAMP, Ch. 2 work paper "SCE 2026 RAMP Optimization.xlsx" spreadsheet, tab "Wildfire."

[165] D.25-08-032, Appendix A, Row 25.2, p. A-20.

[166] D.25-08-032, Appendix A, Row 25.2, p. A-20.

[167] D.25-08-032, Appendix A, Row 26, pp. A-21-A-22.

[168] SCE 2026 RAMP, Ch. 2, p. 31.

[169] SCE 2026 RAMP, Ch. 2, p. 33.

portfolios in the upcoming GRC, it should provide a robust rationale to justify spending above the optimal level in terms of highest BCR and highest benefit, which may be budget scenarios of less than 100 percent.

SCE's mitigation grouping process appears to prioritize capital-intensive mitigations and disregard non-capital mitigations, which may have higher BCRs. SCE's mitigation grouping process also appears to disregard compliance-driven mitigations, as the Utility Reform Network (TURN) noted in its informal comments.[170] SCE should account for these mitigations first, given that they are required.

Moreover, SCE does not sufficiently explain how it accounts for interrelationships, including synergies and diminishing returns, among mitigations within a mitigation group.

In relation to mitigation grouping, SCE mentions that it is exploring and developing an Integrated Grid Planning and Execution (IGPE) framework.[171] SCE expects this framework to result in a single project addressing multiple overlapping grid needs (e.g., asset conditions, wildfire risk, load growth, and reliability constraints) at one location, avoiding the need to return to the same location for multiple projects. SCE explains that as this approach is applied, the recorded costs across programs may differ from initial RAMP cost estimates or GRC forecasts based on how work is ultimately bundled, sequenced, and executed.[172] SPD suggests that SCE closely scrutinize projects it develops under the IGPE framework to determine whether each component of a project is warranted and whether the benefits of not returning to the same location are substantial enough to justify a single project that includes multiple capital-intensive components.

Summary of Findings

SPD finds that:

1. When estimating reliability benefits for location-specific mitigations, SCE blends its territory average residential and non-residential customer CMI values weighted by the mix of each category of customer at the mitigation location but using non-location based, system-wide values; SCE could produce a more accurate CMI value by determining residential and non-residential CMI values using customer input data related to the type of location where it is planning a mitigation.
2. SCE's approach to calculating BCRs has the potential to produce a mathematically invalid BCR value.
3. SCE uses a risk-averse scaling function to account for utility risk attitude.
4. SCE does not present its risk neutral values for comparison in instances where it applies risk-averse scaling.

---

[170] "SCE should include compliance activities in its Mitigation Grouping Framework, as required by the RDF," per Informal Comments of the Utility Reform Network (September 4, 2026), p. 2.

[171] SCE 2026 RAMP, Ch. 2, pp. 32-33.

[172] SCE 2026 RAMP, Ch. 2, p. 32.

5. SCE's optimized portfolios suggest that more constrained budgets produce almost the same benefit as the 100 percent budget.
6. SCE's mitigation grouping process appears to disregard compliance-driven mitigations.
7. SCE does not sufficiently explain how it accounts for interrelationships, including synergies and diminishing returns, among mitigations within a mitigation group.

Recommendations to Address Findings

SPD recommends that SCE:

1. Use customer input data from the type of location where SCE is planning a mitigation to calculate CMI values for customer categories.
2. Use SPD's Method 3 to calculate BCRs in its future RAMP and GRC filings for consistency and to avoid producing a mathematically invalid BCR value.
3. Not only use a risk-averse scaling function to account for utility risk attitude but also ratepayer risk attitude.
4. Present risk neutral values for comparison with instances where SCE applies risk-averse scaling.
5. Provide a robust narrative in the GRC filing to justify spending above the optimum budget level which gives the highest BCR, if that is the SCE proposal.
6. Prioritize compliance-driven mitigations in its mitigation grouping process, given that they are required.
7. More clearly explain how it accounts for interrelationships, including synergies and diminishing returns, among mitigations within a mitigation group.

Evaluation of RAMP Chapters

1. Wildfire and PSPS Risk

Risk Description

Wildfire and PSPS Are SCE's Top Risks

Wildfire and Public Safety Power Shutoff (PSPS) together represent Southern California Edison Company's (SCE) highest-ranked hazard-based enterprise risk. In its 2026 Risk Assessment and Mitigation Phase (RAMP), SCE assigned these risks a combined safety, reliability, and financial risk score approximately six times that of its next-highest enterprise risk, overhead equipment failure.[173] The Safety Policy Division (SPD) observes that wildfire is the most significant risk facing California's investor-owned electric utilities, including SCE.[174]

SCE defines wildfire risk as "ignition events associated with utility operations within the portions of SCE's service area that intersect with SCE's HFRA."[175] Its High Fire Risk Area (HFRA) includes both the California Public Utilities Commission's (CPUC's or Commission's) designated High Fire Threat District (HFTD) and additional locations identified through SCE's own wildfire risk analysis. These additional locations are designated under System Operating Bulletin (SOB) No. 322, which establishes mandatory operating requirements for transmission, subtransmission, and distribution circuits traversing the HFRA during elevated fire weather conditions.[176, 177]

SCE defines PSPS risk as the impacts customers experience when circuits are proactively de-energized during elevated fire weather conditions.[178] Its PSPS risk assessment covers customers served by distribution

---

[173] SCE's Pre-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop Presentation, Dec. 18, 2025, slide 14 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-pre-filing-ramp-workshop-slides_dec-2025.pdf, accessed July 10, 2026). On this slide overhead equipment failure is referenced as "overhead asset failure" (see Chapter 2 of this evaluation report for more information on that risk). According to this slide, in SCE's evaluation for its 2026 RAMP the overall risk score for wildfire and PSPS is 6,152 and the score for overhead equipment failure is 980.

[174] CPUC web page Wildfire and Wildfire Safety (https://www.cpuc.ca.gov/industries-and-topics/wildfires, accessed Aug. 5, 2026).

[175] SCE 2026 RAMP, Chapter 4 "Wildfire and PSPS," p. 9. HFRA refers to the SCE-defined territory it calls its High Fire Risk Area.

[176] SCE 2026 RAMP Ch. 4, pp. 9-10.

[177] SCE 2026 RAMP Ch. 4, Table II-4 "Wildfire Risk Scope," p. 24.

[178] SCE 2026 RAMP Ch. 4, p. 10.

circuits that traverse the HFRA and are forecast to experience conditions exceeding SCE's PSPS thresholds.[179]

SCE reports that the California Department of Forestry and Fire Protection (CAL FIRE) records show the most destructive wildfires in the state occurring in the last 30 years, noting also that climate change is producing hotter, drier conditions, conducive to wildfire, coinciding with fuel accumulation and housing development in the wildland-urban interface (WUI), conditions which are largely outside a utility's control.[180,181] However, fires attributed to power lines account for roughly half of the most destructive fires in the state's history.[182] In particular, it is relevant to note that an initial report from an 18-month investigation by CAL FIRE and the Los Angeles County Fire Department produced the finding that the January 2025 Eaton Fire was caused by "electrical arcing on an out-of-service Southern California Edison transmission tower, ignit[ing] the blaze that killed 19 people and destroyed or damaged more than 9,000 homes and businesses…"[183, 184]

Reducing Wildfire Risk and the Need for PSPS

Utilities use PSPS to reduce wildfire risk by temporarily turning off power in selected areas during dangerous fire weather conditions.[185] Grid hardening can reduce ignition risk and the frequency with which PSPS is needed, although the effect depends on the mitigation installed.

SCE states that covered conductor (CC) and rapid earth fault current limiters (REFCL) can significantly reduce ignition risk and allow circuits to remain energized at higher wind speeds; these technologies do not

---

[179] SCE 2026 RAMP Ch. 4, pp. 10-11; Table XI-45 "PSPS Risk Scope," p. 98.

[180] SCE 2026 RAMP Ch. 4, p. 7.

[181] SCE 2026 RAMP Ch. 4, p. 7, footnote 8, cites passages from the 2026 SB 254 Report (April 7, 2026), including one which indicates the conditions for ignitions "lie largely outside the utilities' direct control and outside of the purview of utility mitigation investments" (p. 27) (https://www.cawildfirefund.com/sites/wildfire/files/documents/2026/sb254-natcatresiliencyreport-locked-4-7-26.pdf, accessed Aug. 5, 2026).

[182] CPUC web page Wildfire and Wildfire Safety (https://www.cpuc.ca.gov/industries-and-topics/wildfires, accessed Aug. 5, 2026). The CPUC cites the CAL FIRE Statistics website as the source of this statistic (https://www.fire.ca.gov/our-impact/statistics, accessed Aug. 5, 2026).

[183] South Pasadenan article "Eaton Fire Investigation Concludes: Electrical Arcing on Idle Edison Tower Caused the Catastrophic Blaze That Killed 19 & Wiped Out Altadena" (Aug. 4, 2026) (https://southpasadenan.com/eaton-fire-investigation-concludes-electrical-arcing-on-idle-edison-tower-caused-the-blaze-that-killed-19/, accessed Aug. 5, 2026).

[184] Although the RAMP doesn't cover risk on the transmission side of an electrical corporation's system (due to the fact that utilities do not seek funding for transmission operations through the GRC process and the RAMP is the precursor to a utility asking for funding for operations through the GRC), this chapter includes a section "Idle and Out-Of-Service Facilities and Transmission Ignition Risk" where SPD discusses this issue in SCE's operations.

[185] CPUC web page Public Safety Power Shutoffs (PSPS) (https://www.cpuc.ca.gov/psps/, accessed Aug. 10, 2026).

eliminate the need for PSPS when conditions exceed the applicable thresholds.[186] SCE asserts that targeted undergrounding (TUG), which moves selected existing overhead lines underground, almost entirely eliminates wildfire risk and virtually eliminates the need for PSPS in the affected locations.[187]

By the end of 2028, SCE plans to underground about 250 miles of overhead conductor, install more than 8,000 miles of CC, and install approximately 12 REFCL ground-fault neutralizers.[188] For 2029-2032, SCE proposes undergrounding an additional 189 miles of overhead conductor and installing 455 miles of CC, paired in some locations with 55 REFCL installations.[189]

These measures should reduce both ignition risk and PSPS risk. SCE nevertheless expects 236 circuit miles within its HFRA to remain unhardened because the benefit-cost ratios (BCRs) for hardening those locations are below 1.0.[190]

SCE's reported residual risk declined by more than 70 percent between 2018 and 2025, from $18,109 million to $5,390 million.[191] Under its proposed plan, SCE projects a smaller reduction of approximately 3.8 percent between 2029 and 2032, from $6,981 million to $6,718 million.[192] These dollar values represent monetized risk estimates.

Improvements to SCE's Wildfire Integrated Model

SCE has revised its Wildfire Integrated Model (WIM) to meet the risk monetization requirements of the Commission's Risk-Based Decision-Making Framework (RDF) Phase 2 Decision. Previously, SCE used a Multi-Attribute Value Function (MAVF) and its Integrated Wildfire Mitigation Strategy (IWMS) to prioritize mitigations.[193] SCE now uses a fully monetized wildfire risk framework that incorporates qualitative factors previously addressed through IWMS directly into its monetized risk estimates.[194]

---

[186] SCE 2026 RAMP Ch. 4, p. 15.

[187] SCE 2026 RAMP Ch. 4, p. 48.

[188] SCE 2026 RAMP Ch. 4, p. 16.

[189] SCE 2026 RAMP Ch. 4, p. 16.

[190] SCE 2026 RAMP Ch. 4, p. 44.

[191] SCE 2026 RAMP Ch. 4 work paper "Wildfire Overall Residual Risk Table" spreadsheet, tab "Sheet1," row 13.

[192] SCE 2026 RAMP Ch. 4 Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk ($000s)," p. 22.

[193] Per D.18-12-014, within Application A.15-05-002 (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=250266979, accessed Aug. 10, 2026).

[194] Per the RDF Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots with Appendices (D.22-12-027 of Dec. 21, 2022) (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668, accessed May 27, 2026).

The enhanced WIM combines two modeling approaches:[195]

1. **Deterministic fire simulations.** Technosylva FireSight 8 uses physics-based simulations to model detailed fire behavior under specified conditions.[196] These simulations provide granular information about potential fire spread but do not represent the full range of possible outcomes.
2. **Stochastic ignition and loss modeling.** Moody's Risk Modeling Solutions (RMS) Wildfire High Definition (HD) data represent a large number of possible ignition and loss scenarios.[197] SCE incorporates these data through a scaling approach to better capture tail risk, including extreme events that may be underrepresented in historical records.

By combining these approaches, SCE expects WIM to estimate wildfire risk at the individual asset level while representing the full distribution of potential outcomes, including extreme tail-risk events.[198]

SCE states that its wildfire likelihood of a risk event (LoRE) values reflect system-wide risk, primarily associated with distribution assets. Its PSPS LoRE values reflect risk at the circuit level.[199]

SCE also made two changes to how it estimates ignition likelihood. First, it refined its Probability of Ignition (POI) algorithms to apply ignition likelihood estimates more appropriately across WIM's expanded distribution of wildfire outcomes. Second, it developed "WIM (Climate)," which incorporates climate projections into risk estimates. SCE intends to use this model to inform long-term infrastructure investments so that they account for future climate conditions.[200]

Incorporating Community Exposure into Risk Scores

SCE has expanded its assessment of wildfire and PSPS consequences to account for community exposure, particularly customer vulnerability and egress—the ability of people to leave an affected area.[201]

The January 2025 fires demonstrated that wildfire consequences do not necessarily increase in proportion to acres burned.[202] SCE observed that relatively small, fast-moving fires near densely populated communities can cause catastrophic harm, particularly where terrain is complex or evacuation routes are limited. These

---

[195] SCE 2026 RAMP Ch. 4, pp. 18-19.

[196] Technosylva web page Wildfire Planning (Firesight™) (2026) (https://technosylva.com/products/wildfire-planning/, accessed Sept. 29, 2026).

[197] Moody's web page Wildfire and bushfire models (2026) (https://www.moodys.com/web/en/us/capabilities/catastrophe-modeling/wildfire.html, accessed Sept. 29, 2026).

[198] SCE 2026 RAMP Ch. 4, pp. 18-19.

[199] SCE 2026 RAMP Ch. 4, p. 23.

[200] SCE 2026 RAMP Ch. 4, p. 19.

[201] SCE 2026 RAMP Ch. 4, pp. 19-20.

[202] SCE 2026 RAMP Ch. 4, pp. 14-15.

observations support considering customer vulnerability and egress alongside traditional fire-spread metrics.[203] To incorporate these factors, SCE developed a unified Community Fire Risk Area (CFRA) framework. It combines Assembly Bill (AB) 2911 assessments of communities identified by CAL FIRE as lacking secondary egress with SCE's existing Fire Risk Egress Areas, Burn-In Buffers, and Communities of Elevated Fire Concern.[204] SCE describes this framework as a way to translate historically qualitative risk factors into quantitative adjustments within the monetized framework required by the RDF Phase 2 Decision.[205] Since its previous RAMP, SCE has incorporated three IWMS components directly into its monetized risk scores.[206] It converts these factors into scalars, or numerical factors used to adjust calculated risk values. SCE describes incorporating these adjustments into its assessment of financial, safety, and reliability consequences; the specific applications discussed below concern monetized safety consequences.

Two scalars address customer vulnerability:[207]

Access and functional needs (AFN). This scalar reflects the concentration of customers with access and functional needs, including people with disabilities, on each circuit.

Non-Residential Critical Infrastructure (NRCI). This scalar reflects the concentration of critical infrastructure customers, such as hospitals, on each circuit.

SCE describes these measures as each circuit's share of the total AFN and NRCI populations within its HFRA (per SCE's RAMP) or as a proportion of SCE's total service territory (per a data request response).[208, 209] This difference affects the denominator used to calculate the scalars and is examined later in this section. SCE applies the AFN and NRCI scalars to the total monetized value of fatalities and serious injuries.[210]

---

[203] SCE 2026 RAMP Ch. 4, pp. 15-16.

[204] AB-2911 Fire Safety (2017-2018) (https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB2911, accessed Aug. 11, 2026).

[205] SCE 2026 RAMP Ch. 4, pp. 19-20.

[206] SCE 2026 RAMP Ch. 4, pp. 34-35.

[207] SCE 2026 RAMP Ch. 4, pp. 35-36.

[208] SCE may calculate these as "a proportion of the total AFN and NRCI populations within SCE's HFRA" per SCE 2026 RAMP Ch. 4, pp. 35-36.

[209] SCE may also calculate these as "each circuit's share of the system-wide population" per SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(c).

[210] SCE 2026 RAMP Ch. 4, pp. 35-36.

The third scalar, the CFRA scalar, addresses community fire exposure, including limited secondary egress. SCE applies this scalar to the safety attribute of its risk assessment.[211]

Observations and Findings

SPD observes that SCE calculates the likelihood of a risk event (LoRE) and consequence of a risk event (CoRE) for wildfire at the asset level.[212] For PSPS, SCE calculates these values at the circuit level.[213]

Observations and Findings on SCE's Wildfire Risk Scope Definition

SCE does not include underground assets or assets outside its HFRA within its definition of wildfire risk scope.[214]

SPD pursued information on the exclusion of underground assets from SCE's wildfire risk definition in a data request, specifically asking "How many ignitions occurred in SCE's service territory between 2014-2025 caused by underground assets?"[215] In response, SCE stated, "SCE has had 357 ignitions across its service territory caused by underground assets from 2014-2025," including that this is out of "a total of 4,286 ignitions over this period."[216] Per SPD calculation, that is approximately 8.3 percent, not a negligible share. However, SCE explained that it "focuses its wildfire mitigation efforts on overhead assets because they represent the primary interface between energized equipment and the external environment where ignition risk is created," and further noted that its models show "lower wildfire ignition relevance for underground asset failures relative to overhead systems."[217]

SPD also pursued information on the exclusion of overhead assets outside SCE's HFRA from its definition of wildfire risk, asking, "Does SCE model wildfire risk outside SCE's HFRA?"[218] In response, SCE stated, "Yes, SCE models wildfire risk across our service territory, including HFRA and non-HFRA."[219] SPD followed up by asking for the number of fires larger than 300 acres and the number of CPUC-reportable

---

[211] Note that SCE writes out CFRA as Community Fire Risk Area (p. 19) but also writes it out as Community Fire Risk Assessment (p. 36) and references it on the same page as "CFRA Assessment" (p. 36, footnote 60). The CFRA scalar description is on SCE 2026 RAMP Ch. 4, p. 36.

[212] SCE 2026 RAMP Ch. 4, pp. 22-23.

[213] SCE 2026 RAMP Ch. 4 work paper "PSPS Overall Residual Risk," p. WP-1.

[214] SCE 2026 RAMP Ch. 4, Table II-4 "Wildfire Risk Scope," p. 24.

[215] Data Request SPD-SCE-2026RAMP-004, Question 5(a).

[216] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 5(a).

[217] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 5.

[218] Data Request SPD-SCE-2026RAMP-004, Question 6.

[219] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 6.

fires[220] that occurred in SCE's service territory outside the HFRA between 2014-2025. SCE responded 64 and 963 fires, respectively.[221] SCE provided a dataset that described the 64 fires larger than 300 acres.[222] SPD's analysis of that dataset found:

- Six of those fires exceeded 10,000 acres, including a 94,736-acre fire in 2023 and a 43,628-acre fire in 2020.[223]
- The total burned acreage across the dataset exceeds 335,000 acres.[224]
- Comparing 2015-2019 with 2020-2024, fire frequency held roughly steady (31 versus 33 fires). However, total acreage burned more than tripled, from approximately 73,600 to 261,900 acres.[225] The increase is concentrated in two years, 2020 and 2023, accounting for approximately 233,000 of those 261,900 acres.[226]

Outside SCE's HFRA, the consequence distribution is heavy-tailed: SCE's decision to exclude fires outside its HFRA from its wildfire risk scope excludes precisely the class of outcomes that SCE designed its tail-risk methodology to capture.

SPD finds the following about SCE's wildfire risk scope definition:

1. SCE limits its wildfire risk scope to overhead distribution and transmission assets within SCE's HFRA, excluding wildfire risk from underground assets and assets located outside the HFRA. However, its data request responses indicated there may be grounds for including those assets in its risk scope.[227] SPD notes that SCE's response indicated that it models risk outside of its HFRA; SCE does not disclose this modeled risk as part of its 2026 RAMP.[228]

---

[220] Specifically, SPD asked, "How many fires meeting the CPUC's Safety Enforcement Division's reportable criteria occurred in SCE's service territory outside the HFRA between 2014-2025?" per Data Request SPD-SCE-2026RAMP-004, Question 8.

[221] SCE response to Data Request SPD-SCE-2026RAMP-004, Questions 7 and 8.

[222] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 7, attachment "SPD-SCE-2026RAMP-004 Question 7 - NonHFRA 300ac 2014_2025.csv."

[223] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 7, attachment "SPD-SCE-2026RAMP-004 Question 7 - NonHFRA 300ac 2014_2025.csv."

[224] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 7, attachment "SPD-SCE-2026RAMP-004 Question 7 - NonHFRA 300ac 2014_2025.csv."

[225] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 7, attachment "SPD-SCE-2026RAMP-004 Question 7 - NonHFRA 300ac 2014_2025.csv."

[226] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 7, attachment "SPD-SCE-2026RAMP-004 Question 7 - NonHFRA 300ac 2014_2025.csv."

[227] SCE response to Data Request SPD-SCE-2026RAMP-004, Questions 5, 7, and 8.

[228] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 6.

Observations and Findings on Risk Scalars

SPD has sought clarification from SCE about its use of risk scalars through the data request process. SPD's concern is not that SCE applies scalars, but that scalars multiply circuit-level risk scores and therefore affect tranche ranking and mitigation sequencing. At the same time, SCE does not document the derivation and numerical effects of each scalar at a level that allows the Commission or parties to reproduce or test the calculations. The RDF Phase 3 Decision also establishes a requirement to present results using a linear scaling function when a utility uses a convex scaling function to present risk-adjusted attribute levels in its tail-risk analysis.[229]

To better understand how SCE uses risk scalars, SPD asked SCE whether the qualitative drivers previously handled through the IWMS (e.g., AFN and NRCI concentration applied as a social vulnerability scalar and the CFRA indices applied as a safety scalar) "can override or modify the outcome of the quantitative BCR analysis" (e.g., would they interrupt the flow shown in SCE's decision-making flow chart[230]).[231] SCE replied, "No."[232]

In related responses, however, SCE confirmed that the scalars could:

- Raise a marginal BCR above 1.0, allowing a circuit that would otherwise fall below the selection threshold to advance. [233]
- Cause SCE to select a different grid-hardening option. [234]

In the same data request, SPD asked SCE if the qualitative drivers affect SCE's selection, prioritization, or sequencing of wildfire mitigations, and to "provide examples showing how the IWMS-informed result compares with a result using just WIM or WIM-Climate."[235] SCE's response did not include an example as requested; instead, it stated: "SCE no longer directly uses IWMS or individual IWMS components in mitigation selection or prioritization. Instead, as directed by the Commission, these components are integrated into monetized risk scores."[236] SCE confirmed in its response to the previous question that scalars could cause a circuit to move from below-threshold to above-threshold in a mitigation selection

---

[229] ...[I]f a utility chooses to address tail risk using the power law or other statistical approach and chooses to present Risk-Adjusted Attribute Levels by relying on a convex scaling function, then it must supplement its analysis by also presenting Risk-Adjusted Attribute Levels by relying on a linear scaling function" per D. 24-05-064, Appendix A, Row 7, p. A-8.

[230] See Figure 1-3 below. SCE 2026 RAMP Ch. 4, Figure III-6 "BCR-Based Decision-Making Flow Chart," p. 42.

[231] Data Request SPD-SCE-2026RAMP-004, Question 14(a).

[232] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 14(a).

[233] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 14(b)(i).

[234] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 14(b)(ii).

[235] Data Request SPD-SCE-2026RAMP-004, Question 15.

[236] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 15.

process. Without an illustrative example of how qualitative drivers converted into scalars might affect mitigation selection, SPD cannot assess the frequency, magnitude, or distribution of the effect of qualitative drivers converted into scalars across SCE's circuit portfolio.

After SPD's request for an example, SPD asked how SCE expects the role of the qualitative components converted into scalars to change over time.[237] SCE responded that it "expects these scalars to remain embedded in its wildfire grid hardening and prioritization process."[238] SCE went on to state that, due to unhardened miles declining "significantly" in the future, SCE expects "the material impact of these scalars on grid hardening decisions … to diminish."[239] In other words, SCE is not planning to refine or review the process of integrating these scalars into its modeling; it expects their impact to diminish because the pool of circuits to which they apply is expected to shrink.

In the same data request, SPD sought to explore how SCE calculates its three scalars derived from qualitative drivers (encompassing the factors of vulnerable population and critical facility concentrations and limited secondary egress): (1) the AFN customer scalar, (2) the NRCI customer scalar, and (3) the CFRA scalar.[240] SCE states in its RAMP application that the first two factors are "expressed as a proportion of the total AFN and NRCI populations within SCE's HFRA."[241] In its response to SPD's data request, SCE stated that "SCE calculates the AFN and NRCI scalars as each circuit's share of the system-wide population" (i.e., not just SCE's HFRA).[242] Whether it is a proportion of the total in the HFRA or in the whole system, the intention is to avoid "localized percentage effects that may distort results."[243]

As for the third scalar regarding egress, the CFRA scalar, it is a "normalized index (0–1)" derived from geospatial analysis of factors that exacerbate wildfire consequence, including limited egress and historical fire exposure.[244] SCE applies this scalar to the safety attribute "as a location-specific modifier … at the circuit-segment level."[245] SCE adds that this scalar is "bounded between zero and one" so "that it functions as a targeted adjustment rather than a dominant driver of results." [246]

---

[237] Data Request SPD-SCE-2026RAMP-004, Question 16.

[238] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 16.

[239] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 16.

[240] Data Request SPD-SCE-2026RAMP-004, Question 9.

[241] SCE 2026 RAMP Ch. 4, pp. 35-36.

[242] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(c).

[243] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(c).

[244] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(a).

[245] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(a).

[246] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(a).

According to SCE's data request response, SCE constructs the CFRA scalar per hexagon as:

$$\text{Score}_p = F_p \times E_p$$

where p is a hexagon, F_p is a Fire Frequency Index and E_p an Egress Constraint Index, each an integer from 1 to 9.

SCE classifies hexagons scoring greater than or equal to 45 as Fire Risk Egress Locations and normalizes them as $(\text{Score}_p - 45)/\ 81 - 45$. SCE then applies a lower bound such that the operative range is [0.55, 1.0] "to ensure bounded influence in monetized outcomes."[247] SCE has three other categories of hexagons where it assigns its CFRA scalar differently: Burn-In Buffer areas (assigned at 0.55), Communities of Elevated Fire Concern (CEFCs) (assigned at 1.0), and AB 2911 community locations[248] (assigned at 1.0).[249, 250] SCE next assigns each hexagon a "Composite Plexel CFRA Scalar" by priority (CEFC, then AB 2911, then Burn-In Buffer, then the egress score, otherwise zero). It then calculates a circuit segment-level CFRA scalar as a weighted sum of hexagon values and applies a "spatial weighting factor (e.g., based on population, area, or exposure within the circuit segment)," where the sum of all spatial weighting factors is equal to one.[251]

CFRA inputs include historical fire frequency (e.g., per the CAL FIRE Fire and Resource Assessment Program [FRAP] datasets), population egress constraints (e.g., road network and population density), CAL FIRE designations (e.g., AB 2911), and internal subject matter expert judgment (e.g., CEFC).[252]

SPD asked SCE to further elaborate on how it applies each of these scalars to the monetized value of fatalities and serious injuries.[253] SCE responded that it "applies AFN, NRCI, and CFRA scalars to its total monetized safety consequence value, which is based on estimates of fatalities and serious injuries."[254]

In application, that means that SCE first computes a total monetized safety consequence value. The AFN and NRCI scalars are then combined additively into a composite social vulnerability score, applied

---

[247] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(a).

[248] AB-2911 Fire Safety (2017-2018) (https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB2911, accessed Aug. 11, 2026).

[249] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(a).

[250] SCE 2026 RAMP Ch. 4, pp. 16-17.

[251] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(a).

[252] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(a).

[253] Data Request SPD-SCE-2026RAMP-004, Question 9(b).

[254] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(b).

multiplicatively to that base value. SCE subsequently applies the CFRA scalar as a separate multiplicative adjustment.[255] The complete formulation to get the safety consequence value for each circuit segment "i" is:

$$\text{Safety}_{i}^{\text{final}} = \text{Safety}_{i}^{\text{base}} \times (1 + \text{AFN}_i + \text{NRCI}_i) \times (1 + S_i^{\text{CFRA}})$$

where S_i^{CFRA} is the CFRA scalar for a circuit segment.[256]

SPD inquired, "how does SCE avoid counting circuit population size twice, once in the monetized safety value and again in the AFN and NRCI share calculation?" SCE stated that it incorporates the base population once in the underlying estimated consequence values, with the social vulnerability scalars only adjusting those values based on customer characteristics as a share of the population.[257] SCE does not use the scalars to rescale the population, so the model does not count population size twice. SCE stated that "the scalars provide a targeted, proportional adjustment that reflects differences in vulnerability or criticality across circuits without altering the underlying exposure term."[258]

In response to SPD asking at what stage and scale SCE applies its risk scalars, SCE responded that it applies all three scalars at the circuit-segment level during the monetized safety-risk calculation stage.[259]

In response to SPD's question about the source and date of the data SCE uses to identify AFN customers, NRCI customers, and CFRA-area circuits, SCE responded that it extracted AFN and NRCI datasets from internal databases in August 2025.[260] To define CFRA-area circuits, SCE stated that it uses CAL FIRE FRAP perimeter data (September 2024), road network and population datasets (September 2024), and CEFC and AB 2911 datasets (August 2025).[261]

SPD asked SCE to provide the values for each of the three scalars for every RRU in SCE's service territory and provide them at the circuit level for scalar values that are not available at the RRU level.[262] In response, SCE provided the values for each of the three scalars for every RRU at the circuit level in SCE's service territory, noting that the RRUs are only in SCE's HFRA.[263]

SPD finds the following about SCE's use of risk scalars:

---

[255] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(b).

[256] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(b).

[257] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(d)(i)(1).

[258] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(d)(i)(1).

[259] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(f) and (g).

[260] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(e).

[261] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(e).

[262] Data Request SPD-SCE-2026RAMP-004, Questions 9(j).

[263] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(j), attachment "2025_afn_ncri_question9i.csv."

2. SCE applies a social vulnerability scalar to the monetized value of fatalities and serious injuries, calculated as each circuit's share of the total AFN and NRCI populations within SCE's HFRA. SPD observes that this is a share of a system-wide (or HFRA) total, not a vulnerability rate: it increases with the absolute number of AFN and NRCI customers on a circuit, and therefore with circuit size. As a result, a large circuit in an area of average vulnerability could receive a higher-value scalar than a smaller circuit serving a more vulnerable community, meaning the scalar appears to capture circuit size as much as differential vulnerability. This raises a double-counting concern, if the monetized fatality and serious-injury value already scales with exposed population, a second factor that also rises with population count weights exposure twice.

3. SPD notes that SCE incorporates at least three qualitative IWMS components directly into its monetized risk scores, converting them into scalars and applying them to its baseline risk modeling outputs: the AFN, NRCI, and CFRA scalars.[264] SCE applies these scalars multiplicatively, so their effects stack on the baseline model outputs. SPD observes that where any of the three scalars produces a non-trivial adjustment, the numerical effect is driven almost entirely by the CFRA scalar. Referencing attachments submitted by SCE in response to two SPD data requests, SPD calculates that the AFN and NRCI scalars together raise monetized safety consequences by approximately 0.05 percent on average (maximum about 0.33 percent), whereas the CFRA scalar, as provided by SCE, takes values from 1.0 to 2.0 and raises monetized safety consequences by approximately 55.6 to 100 percent wherever it applies.[265, 266] Of the 4,161 CFRA scalar values SCE provided, 3,499 (84.1 percent) equal 1.0 (no adjustment) and 662 (15.9 percent) exceed 1.0.[267] The CFRA scalar is discontinuous: no value falls in the interval (1.0, 1.556), so a circuit receiving any CFRA adjustment jumps directly from 1.0 to a minimum of 1.556 up to a maximum of 2.0, a 100 percent increase.[268] The field takes only nine distinct values, consistent with the 1-to-9 ranked/binned egress index SCE describes.[269]

SPD further observes that SCE incorporates at least three qualitative IWMS components into its risk score, the AFN, NRCI, and CFRA scalars.[270] While SCE stated in a data request response that these scalars do not

---

[264] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9.

[265] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 9(j), attachment "2025_afn_ncri_question9i.csv."

[266] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 5, attachment "cfra.csv."

[267] SPD calculations using data from SCE response to Data Request SPD-SCE-2026RAMP-010, Question 5, attachment "cfra.csv."

[268] SPD calculations using numbers from SCE response to Data Request SPD-SCE-2026RAMP-010, Question 5, attachment "cfra.csv."

[269] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 6(b).

[270] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 14.

override the BCR decision flow, it confirmed the scalars can lift a marginal BCR above 1.0, allowing a circuit that would otherwise fall below the 1.0 selection threshold to advance.[271] SCE stated that it expects these scalars to remain embedded in its grid-hardening prioritization process.[272]

Observations About SCE's Use of Customer Minutes Interrupted Estimates

In its 2026 RAMP, SCE monetizes impacts to the reliability attribute using the Interruption Cost Estimate (ICE) Calculator[273] with "assumptions specific to SCE's operating environment," estimating $0.09 per customer minute interrupted (CMI) for residential customers and $41.62 per CMI for non-residential customers.[274] In response to data requests from SPD, SCE clarified that the specific assumptions it used to generate those estimates include a "System Average Interruption Duration Index (SAIDI) of 144.42 and System Average Interruption Frequency Index (SAIFI) of 1.04, based on a 10-year average (2014-2023) from SCE's 2024 Annual Reliability Report, excluding Major Event Days (MEDs)."[275] These inputs imply an average interruption duration (i.e., Customer Average Interruption Duration Index [CAIDI]) of approximately 139 minutes.[276] SCE stated in the same data request response that "[f]or wildfire scenarios, SCE applies an assumed outage duration of approximately eight hours, which informs the estimated CMI prior to monetization."[277] Given that SCE's per-CMI values come from shorter-duration outages, it is not clear that those values would hold for outages several times longer than those that SCE simulates in wildfire scenarios.

In the same data request response, SCE also confirmed that it applies the ICE Calculator outputs as "fixed class-average values, rather than dynamically adjusting them by geography, time of day, or seasonal conditions at the circuit level."[278] However, SCE added that "each circuit's monetized reliability value reflects its specific mix of residential and non-residential customers, resulting in location-specific weighting of reliability impacts."[279] Because the non-residential CMI value ($41.62) is approximately 462 times the residential value ($0.09) per SPD calculation, the monetized reliability benefit is driven primarily by the non-residential customer share.

---

271 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 14(b)(i).

272 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 16.

273 The Interruption Cost Estimate (ICE) Calculator (https://icecalculator.com/, accessed Aug. 14, 2026).

274 SCE 2026 RAMP Ch. 4, p. 36.

275 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 12.

276 Calculated by SPD by dividing 144.42 by 1.04.

277 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 10(a).

278 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 11(a).

279 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 11(a).

To further explore how SCE uses its CMI values, SPD asked SCE to provide a step-by-step example showing SCE's reliability value calculation for one RRU in SCE's HFRA.[280] In SCE's example, non-residential customers represent only 10,000 of the 110,000 total CMI but drive $416,200 of the $425,200 total monetized reliability value.[281] In this example, non-residential load drives about 98 percent of the monetized reliability benefit while contributing under 10 percent of total CMI.

SPD finds the following about SCE's use of CMI estimates:

4. SCE's ICE Calculator inputs are based on a 2014-2023 system-average SAIDI/SAIFI dataset that excludes MEDs. Excluding MEDs means that catastrophic conditions may not be incorporated into SCE's calculations.

5. SCE's SAIDI and SAIFI inputs imply an average interruption duration (CAIDI, computed as SAIDI divided by SAIFI) of approximately 139 minutes, while SCE applies an assumed outage duration of approximately eight hours, or 480 minutes, for wildfire scenarios. The per-CMI values SCE obtained from the ICE Calculator come from short, routine (non-MED) outages. SCE has not shown that those values hold for the approximately eight-hour outages it assumes in wildfire scenarios, several times longer than the routine outages underlying those values.

6. SCE applies the ICE Calculator values as fixed class-average values and does not dynamically adjust them by geography, time of day, or seasonal conditions at the circuit level, adjusting only for the mix of residential and non-residential customers.[282] As a result, circuit-level variation in monetized reliability value is driven solely by customer class mix rather than event-specific outage characteristics.

7. According to SCE's example in its data request response, non-residential load appears to drive approximately 98 percent of the monetized reliability benefit while contributing under 10 percent of total CMI. The monetized benefit is therefore highly sensitive to the number of non-residential customers on wildfire and PSPS-affected circuits, and comparatively insensitive to the number of residential customers, the most common customer classification in SCE's HFRA.

[280] Data Request SPD-SCE-2026RAMP-004, Question 13.

[281] Data Request SPD-SCE-2026RAMP-004, Question 13.

[282] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 11(a).

Risk Bow Ties

Wildfire

SCE presents the following risk bow tie for wildfire risk:

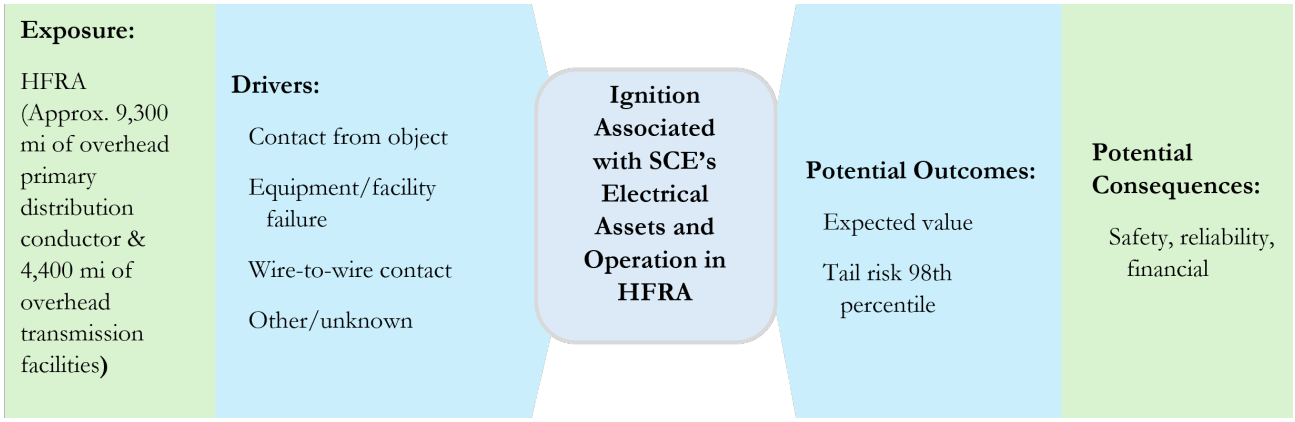


Figure 1-1. SPD Adaptation of SCE Wildfire Risk Bow Tie.[283]

PSPS

SCE presents the following risk bow tie for PSPS risk:

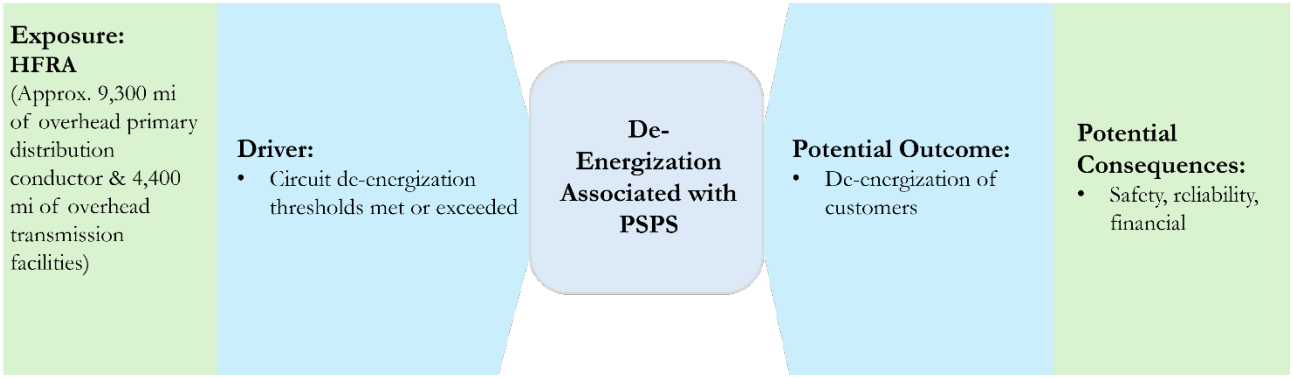


Figure 1-2. SPD Adaptation of SCE PSPS Risk Bow Tie.[284]

As shown in Figures 1-1 and 1-2, both risk bow ties identify the same exposure: approximately 9,300 miles of overhead primary distribution conductor and approximately 4,400 miles of overhead transmission facilities within the HFRA. The two bow ties diverge at the driver stage. For wildfire risk, the drivers are contact from object; equipment or facility failure; wire-to-wire contact; and other or unknown causes, which give rise to the triggering event of an ignition associated with SCE's electrical assets and operations in the

[283] SCE 2026 RAMP Ch. 4, Figure II-4 "Risk Bowtie for Wildfire Risk," p. 25.

[284] SCE 2026 RAMP Ch. 4, Figure XI-9 "Risk Bowtie for PSPS Risk," p. 99.

HFRA. For PSPS risk, the sole driver is the forecast of environmental conditions, driven by dry fuels and high winds, that meet or exceed SCE's established circuit de-energization thresholds, triggering the de-energization event associated with PSPS. The wildfire outcome is characterized by expected value and tail risk at the 98th percentile, while the PSPS outcome is customer de-energization. SCE estimates that both risks could have safety, reliability, and financial consequences. SCE's exposure and drivers are further discussed in the sections that follow.

Observations and Findings

SPD has no observations or findings on the risk bow ties.

Exposure

SCE defines both its wildfire and PSPS risk exposure as its HFRA, consisting of approximately 9,300 miles of overhead primary distribution conductor and 4,400 miles of overhead transmission facilities.[285, 286]

Reflecting planned hardening through the end of 2028, SCE preliminarily estimates that roughly 880 HFRA primary distribution circuit miles will remain unhardened at the start of the 2029-2032 RAMP period.[287]

Observations and Findings

Other than the finding on the wildfire risk scope noted above, SPD has no observations or findings on the exposure for these risks.

[285] SCE 2026 RAMP Ch. 4, Figure II-4 "Risk Bowtie for Wildfire Risk," p. 25.

[286] SCE 2026 RAMP Ch. 4, Figure XI-9 "Risk Bowtie for PSPS Risk," p. 99.

[287] SCE 2026 RAMP Ch. 4, p. 39.

Tranches

Wildfire

SCE states that it evaluates wildfire risk using a quintile-based tranching framework.[288] Under this approach, SCE categorizes wildfire risk within its HFRA by combining quintiles of LoRE and CoRE values, producing a 5×5 framework with 25 risk tranches, illustrated in Figure 1-1 below.

SCE states that, for wildfire risk, the "higher-risk tranches represent groups of assets with both a higher likelihood of wildfire ignition and more severe potential consequences."[289] SCE further states that it "prioritizes mitigation deployment to the highest-risk tranches and applies proportionally less emphasis to lower-risk tranches."[290] SCE states that it uses this tranching framework to evaluate the cost-effectiveness of proposed wildfire mitigations on a tranche-by-tranche basis.[291]

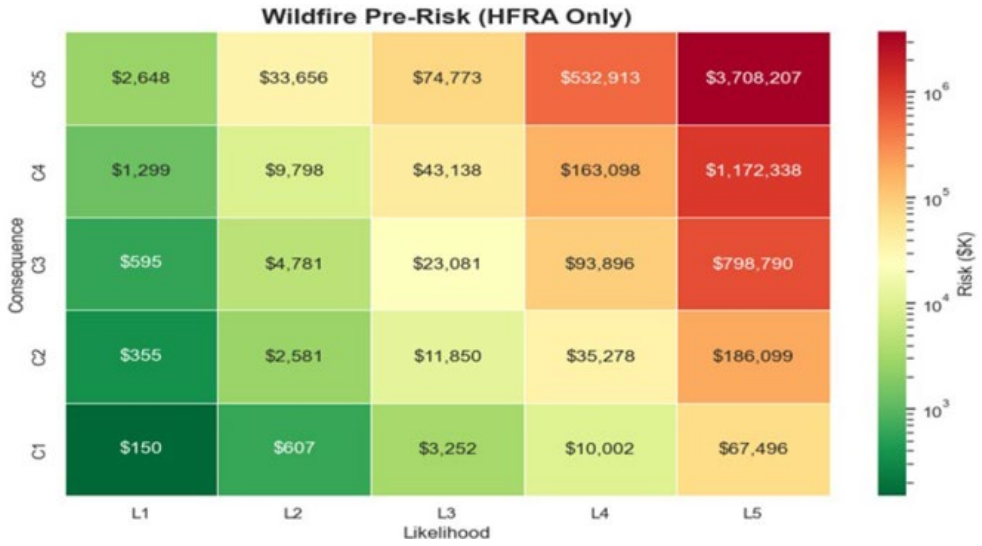


Figure 1-3. Quintile Tranching of Wildfire Risk Across SCE's HFRA in 2029 Using LoRE and CoRE Values[292]

[288] SCE 2026 RAMP Ch. 4, p. 37.

[289] SCE 2026 RAMP Ch. 4, p. 37.

[290] SCE 2026 RAMP Ch. 4, p. 37.

[291] SCE 2026 RAMP Ch. 4, p. 37.

[292] This is a figure from SCE 2026 RAMP Ch. 4, Figure II-5 "Distribution of Wildfire Risk across SCE System's [sic] in 2029," p. 38. SCE labels this figure as showing the risk across SCE's system but then labels it as "HFRA only," so it appears to not show the risk across SCE's whole system. SPD understands the term "pre-risk" used in the label on the figure to mean "pre-mitigated risk."

PSPS

SCE uses the same quintile approach to tranching PSPS risk.[293] SCE states that, for PSPS risk, "higher-risk tranches represent groups of assets with both a higher likelihood of a proactive de-energization event and more customers in scope [for experiencing de-energization] thereby representing more severe potential consequences."[294] While SCE states that it prioritizes higher-risk tranches as with wildfire, it also states that "several PSPS programs are designed to target specific populations (e.g., AFN customers, rural populations, etc.) rather than the highest risk."[295]

Observations and Findings

For wildfire risk, SPD examined whether the mitigation benefits SCE reports at the Risk Reporting Unit (RRU) level are consistent with the tranche assignments SCE derives from this framework. If tranche level reflects relative risk as SCE describes, RRUs assigned to the highest LoRE and CoRE quintiles (i.e., L5 and C5) would be expected to have the largest estimated mitigation benefits in total or per unit of work performed. Analyzing SCE's Chapter 4 work paper "Wildfire Benefit Cost Ratio Calculations," SPD identifies RRUs that depart substantially from SCE's tranche ordering (see Tables 1-1 and 1-2).[296]

[293] SCE 2026 RAMP Ch. 4, pp. 102-103.

[294] SCE 2026 RAMP Ch. 4, p. 102.

[295] SCE 2026 RAMP Ch. 4, p. 102.

[296] SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tab "WF-C1-CoveredConductor," columns "Tranche Level," "Total Work Units," and "Mitigation Benefit (WACC Calc)." Mitigation benefit per work unit is calculated by SPD as reported mitigation benefit divided by reported total work units.

Table 1-1. Reported Mitigation Benefit by Tranche Assignment, Selected Covered Conductor RRUs[297,298]

RRU	Tranche Level	Total Work Units	Mitigation Benefit (WACC)	Mitigation Benefit per Work Unit
Ambercrest	L1-C2	0.00179	$13,029,740	$7,295,997,949
Pampas	L1-C1	0.00420	$6,672,473	$1,589,661,872
Crab	L5-C4	0.25499	$168,674	$661,490
Arapaho	L5-C5	0.16118	$24,326	$150,931

Table 1-2. LoRE and CoRE for Selected Covered Conductor RRUs[299]

RRU	Tranche	LoRE	CoRE
Ambercrest	L1-C2	0.000166	$5.53 billion
Pampas	L1-C1	0.0000383	$14.18 billion
Crab	L5-C4	0.0570	$106 million
Arapaho	L5-C5	0.0747	$139 million

[297] SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tab "WF-C1-CoveredConductor," columns "Tranche Level," "Total Work Units," and "Mitigation Benefit (WACC Calc)." Mitigation benefit per work unit is calculated by SPD by dividing reported mitigation benefit by reported total work units.

[298] The four RRUs in this table have the following designations under column "RRU ID" in the Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet: ElectricOps.Wildfire.AMBERCREST.Grid_Hardening; ElectricOps.Wildfire.PAMPAS.Grid_Hardening; ElectricOps.Wildfire.CRAB.Grid_Hardening; ElectricOps.Wildfire.ARAPAHO.Grid_Hardening.

[299] SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tab "WF-C1-CoveredConductor," columns "Tranche Level," "Pre Mitigated Likelihood of Risk Event"; CoRE values in the table is calculated by SPD by summing columns "Pre Mitigated Safety Consequences," "Pre Mitigated Reliability Consequences," and "Pre Mitigated Financial Consequences."

Table 1-1 shows the mitigation benefit per work unit for four RRUs where SCE plans to install CC. Breaking down the pre-mitigated risk, which informs the tranche level, SPD sees the same inconsistencies. The two RRUs assigned to the lowest or near-lowest level tranches, Ambercrest (tranche L1-C2) and Pampas (tranche L1-C1), have estimated mitigation benefits approximately 536 and 274 times greater, respectively, than the benefit SCE expects from the Arapaho RRU, which SCE assigns to the highest tranche (L5-C5), and approximately 77 and 40 times greater than the benefit SCE estimates from the Crab RRU, which is assigned to nearly the highest tranche (L5-C4). On a per-work-unit basis, the divergence is larger by several orders of magnitude. Additional low-tranche RRUs exhibit the same characteristic, including Nordic (L4-C1, 0.02776 work units, with a mitigation benefit per work unit of $15,593,547) and La Vaca (L3-C2, 0.00898 work units, with a mitigation benefit per work unit of $11,731,861), each with an estimated benefit exceeding that of 14 of the 24 RRUs assigned to the highest tranche, L5-C5.

Table 1-2 shows SCE's estimated LoRE and CoRE values for the RRUs listed in Table 1-1. SCE assigns Ambercrest to the second-lowest consequence tranche (C2), yet its reported CoRE is approximately 40 times larger than that of Arapaho, which SCE assigns to the highest consequence tranche (C5). SPD sees these inconsistencies in many of SCE's RRUs.

SPD cannot reconcile these RRU-level results with SCE's description of the relationship between tranche level and risk. SCE's estimated values imply that CC installed on 0.00179 work units at Ambercrest would reduce that RRU's annual risk from $919,008 to $3,369, a reduction of approximately 99.6 percent, while CC installed on 0.16118 work units at Arapaho would reduce that RRU's annual risk from $10,402,463 to $10,400,754, a reduction of approximately 0.016 percent.[300]

SPD explored SCE's assignment of risk tranche levels to different RRUs through a data request, asking SCE why, in the case of these four RRUs, SCE estimates much higher mitigation benefits for low-risk tranches than for high-risk tranches.[301] SPD also asked SCE to explain how it assigns tranche levels to each RRU.[302] In its response, SCE attributed the divergence in expected benefit from risk tranche level to three factors: (1) estimated mitigation benefits include avoided PSPS risk in addition to wildfire risk, so an RRU with low wildfire risk may still show a high benefit; (2) benefits reflect "cumulative risk reductions over the full useful life of the mitigation," modeled at 55 years for CC and TUG, rather than a single-year risk score; and (3), for the Crab and Arapaho RRUs, the estimated risk values include all segments while the estimated mitigation benefits reflect only the benefits from the segments "that have forecast scope" (i.e., that SCE plans to harden).[303]

Regarding how SCE assigns tranche levels to each RRU, SCE responded, "[t]ranche assignments are based on the relative wildfire risk characteristics of an RRU starting in 2029," and further explained that SCE sets

---

[300] SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tab "WF-C1-CoveredConductor."

[301] Data Request SPD-SCE-2026RAMP-010, Question 3.

[302] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 3(b).

[303] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 3(a).

tranche thresholds using quintiles of the modeled LoRE and CoRE distributions and that SCE "assigns tranche levels based on the wildfire risk characteristics of HFRA segments associated with each RRU," (i.e. each RRU's tranche level is based on a pre-mitigation risk level, not an estimated mitigation benefit).[304]

The three factors to which SCE attributes the divergence between tranche level and estimated mitigation benefit do not fully explain the divergence SPD found in the four RRUs in question. The useful-life horizon does not explain a divergence in ordering: the present-value discount factor is common to all RRUs of a given mitigation, so it scales every RRU's benefit by the same factor and preserves their rank. Where post-mitigation risk is a fixed fraction of pre-mitigated risk, mitigation benefit is proportional to pre-mitigated risk and tracks the tranche ranking; the horizon changes the magnitude of every benefit but not their relative order. Therefore, SPD rejects SCE's "cumulative risk reductions over the full useful life of the mitigation" factor to explain the divergence.

This leaves two other factors to consider: PSPS risk reduction not captured in the wildfire LoRE/CoRE tranches, and the segment-scope mismatch under which the reported risk reflects all segments while the mitigation benefit reflects only the benefit from segments SCE plans to harden. If the PSPS risk reduction is not included in the calculation of pre-mitigated risk, then it makes sense that this might affect the mitigation benefit. However, SCE should either consistently include PSPS risk in the pre-mitigated risk (LoRE/CoRE) and PSPS mitigation benefit in the benefit, or exclude PSPS from both, not add it in only on the benefit side.

Regarding the third factor, the segment-scope mismatch, SPD understands how this might affect the mitigation benefit. However, SCE should show pre-mitigated risk at the same level as it is performing mitigation, not pre-mitigated risk for the whole RRU (circuit) and the mitigation benefit for just a small portion of the RRU (circuit).

SPD finds the following about SCE's approach to tranching:

8. Where SCE discusses its "wildfire lessons learned" in its RAMP application, it notes that it tried to respond to SPD's recommendation from SPD's evaluation of Sempra's 2025 RAMP that San Diego Gas & Electric Company (SDG&E) "provide a clear crosswalk from each mitigation segment to its corresponding risk tranche and show tranche-level BCRs to justify selection."[305] SCE states that it responded by "expand[ing] narrative transparency in describing how 5×5 tranching, risk-averse scaling, and circuit-level BCR logic shape mitigation selections across both wildfire grid hardening and PSPS-impact-reduction strategies."[306] SPD did not find in SCE's RAMP application or work papers a segment-to-tranche crosswalk, nor is SPD able to trace any mitigation segment to its corresponding risk tranche from SCE's RAMP application or work papers as submitted.

---

[304] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 3(b) and (c).

[305] SCE 2026 RAMP Ch. 4, p. 92.

[306] SCE 2026 RAMP Ch. 4, p. 92.

SPD finds the following about SCE's assignment of tranches to RRUs:

9. SCE describes a quintile-based tranching framework under which SCE prioritizes the highest-risk tranches for mitigation, but the RRU-level mitigation benefits SCE presents in its Chapter 4 work paper "Wildfire Benefit Cost Ratio Calculations" do not correspond to that ordering for certain RRUs. As shown in Table 1-1, RRUs SCE assigned to the lowest tranches have estimated mitigation benefits substantially exceeding those of RRUs SCE assigned to the highest tranches, for example, Ambercrest (L1-C2) with an estimated benefit of about $13,029,740, compared to Arapaho (L5-C5) with an estimated benefit of about $24,326. The discrepancy is significantly larger on a mitigation-benefit-per-work-unit basis. Table 1-2 shows that SCE assigned Ambercrest to the second-lowest consequence tranche (C2), yet its reported CoRE is approximately 40 times that of Arapaho, which SCE assigned to the highest consequence tranche (C5). The same pattern appears for Pampas, which SCE assigned to the lowest consequence tranche (C1), with an estimated CoRE that is approximately 102 times that of Arapaho. SPD takes issue with the three factors that SCE reported as reasons why the tranche level and mitigation benefits diverge.

10. SCE only assigns risk tranches to RRUs where it plans to perform mitigation. SCE's Chapter 4 work paper "Wildfire Benefit Cost Ratio Calculations" presents 448 RRUs in the CC and TUG tabs, which is also the complete set of RRUs for which SCE modeled the CC, TUG, or CC plus REFCL mitigations. In a data request response, SCE reported 1,252 RRUs, of which 854 fall outside that set, including circuits such as Shovel, Bootlegger, and Titan, which carry substantial reported wildfire risk, but for which SCE does not propose CC, TUG, or CC plus REFCL mitigation.[307] SCE does not assign any of these 854 RRUs to a tranche. Under the RDF Phase 3 Decision, tranching is intended to segment a utility's RRUs, circuit segments, or assets so that mitigation can be prioritized toward the segments carrying the greatest risk.[308] If SCE assigns only RRUs it already selected for mitigation to tranches, it defeats the purpose of using tranching to prioritize assets for mitigation.

11. As indicated by the above findings, SPD cannot verify from SCE's RAMP application and work papers that SCE's tranching framework supports the prioritization function SCE attributes to it. First, SCE reports tranche assignments only for the 448 RRUs it already selected for mitigation, so SCE cannot rank its full set of assets with wildfire exposure, including potential RRUs that SCE didn't select for mitigation, and prioritize mitigation work accordingly. Second, considering the RRUs SCE selected for mitigation, SCE's estimated mitigation benefits do not align with the tranche ordering as SPD would expect. In other words, SPD is not able to verify that the greatest benefits

[307] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 34.

[308] "Filing of RAMP analyses using LoRE/CoRE quintile tranches will aid the Commission and parties understand if a utility is requesting funding for mitigations in the riskiest portions of their infrastructure and/or management system. This is essential if the Commission is to ensure strategic targeting of mitigations such that the greatest risk reduction benefits are achieved at the lowest cost, while taking into account the need to minimize risks as quickly as possible. Ensuring the greatest risk reduction benefits are achieved at the lowest cost is essential to ensuring just, reasonable, and affordable rates," per D.24-05-064, p. 28.

from risk mitigations are found within the highest-risk tranches. SCE's estimated consequence values underlying some tranche assignments are inconsistent with the tranche to which SCE assigned the RRU, with some RRUs in the lowest tranches having estimated mitigation benefits substantially exceeding those of RRUs in the highest risk tranches. SPD is unable to determine from SCE's work papers and data request responses if this apparent misalignment reflects an error in the tranche assignment, the estimated consequence values, or in the estimated mitigation benefit. The three factors SCE identifies in its data request response as accounting for the apparent misalignment between tranche assignment and estimated mitigation benefit are not satisfactory to SPD.[309] SCE's uneven incorporation of risk, benefit, and cost contributes to SPD's inability to verify that SCE's tranching framework performs the prioritization function SCE attributes to it. For example, SCE includes PSPS risk reduction in mitigation benefits but not in the pre-mitigated risk used to form tranches, and it includes secondary and service-line costs while excluding the associated risk.

Risk Reporting Units (RRUs)

Wildfire

SCE defines its RRU for wildfire risk as "all the portions of a given circuit within SCE HFRA."[310] SCE states that this RRU definition "reflects the residual wildfire risk remaining on the system after accounting for completed grid-hardening activities" and "enables SCE to evaluate wildfire risk and mitigation effectiveness on a consistent basis across alternative mitigation portfolios," accounting for partial hardening of a circuit and measures that support circuit-wide hardening.[311] SCE notes that it previously strategized for hardening at the circuit-segment level, but is shifting to a circuit-level unit of analysis to address inefficiencies it found in that approach.[312]

PSPS

Regarding SCE's PSPS RRUs, the RDF Phase 4 Decision requires that utilities define an RRU for each mitigation, with some exemptions.[313] The Phase 4 Decision exempted PSPS and protective equipment device settings from needing defined RRUs.[314] SCE notes that it "evaluates [PSPS-related] customer programs at the system level, rather than at the RRU level" because "PSPS-related customer programs are

---

[309] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 3.

[310] SCE 2026 RAMP Ch. 4, p. 38.

[311] SCE 2026 RAMP Ch. 4, p. 38.

[312] SCE 2026 RAMP Ch. 4, pp. 38-39.

[313] D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[314] "The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following: 1. Public Safety Power Shutoffs; 2. Protective Equipment Device Settings; 3. Mitigation and Control Programs that do not meet the following thresholds: a. For PG&E and SCE, $10 million…" from D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

implemented broadly across SCE's HFRA and are designed to serve specific customer populations (e.g., AFN customers) rather than discrete circuit segments," so PSPS risk mitigations cannot be "meaningfully be attributed to individual RRUs."[315] Nonetheless, SCE chose to define an RRU for PSPS risk to help compare possible hardening measures as part of its alternative portfolio analysis for PSPS.[316] SCE's PSPS RRU consists of the "remaining unhardened portions of the circuit subject to PSPS events," "allow[ing] SCE to transparently assess PSPS risk reductions that result from grid-hardening investments in a consistent manner."[317]

Observations and Findings

Circuit-Level RRU Costs and Secondary and Service Lines

SCE calculates risk and benefit-cost ratios (BCRs) and selects mitigations using circuit-level risk reporting units (RRUs). Each RRU's boundary therefore defines the scope of the benefit and cost estimates used to prioritize projects. SPD is concerned that SCE's circuit-level approach to project prioritization includes the costs of mitigating secondary and service lines but excludes the risk associated with those assets from its pre-mitigation risk estimates. The RRU scope should be consistent for risk and cost: if SCE includes secondary and service lines in the RRU mitigation costs, it should include those lines in its RRU pre-mitigated risk calculation; alternatively, it should exclude secondary and service lines from both.

SPD explored the issue of RRU-level cost calculations and the question of secondary and service lines through a data request. In response to an inquiry as to whether CC and TUG estimated miles and costs included secondary and service lines, SCE responded that the estimated mileage in its 2026 RAMP[318] reflects "primary distribution circuit miles only," but the costs include a blend of all project-related costs, including "all project-related scope necessary to deliver a complete hardening solution, including secondary and service line work where applicable."[319] SCE clarified in another response that the cost of hardening secondary and service lines is included in SCE's spend and per-mile cost metrics, while SCE does not "explicitly" include wildfire risk "associated with secondary and service lines … in current circuit ranking outputs."[320,321] SPD asked, "How does SCE calculate the per mile cost based on the primary and secondary

[315] SCE 2026 RAMP Ch. 4, p. 103.

[316] SCE 2026 RAMP Ch. 4, p. 104.

[317] SCE 2026 RAMP Ch. 4, p. 104.

[318] SCE 2026 RAMP Ch. 4, Table IV-10 "2029-2032 Estimated WCCP Miles and Spend," p. 48; Table IV-11 "2029-2032 Estimated TUG Circuit (Overhead) Miles and Spend," p. 50.

[319] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 17.

[320] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 18.

[321] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 19.

line hardening work?" SCE explained, "SCE calculates per-mile hardening cost as the total regional project cost divided by the miles of primary conductor installed. Secondary line work is not tracked as a standalone mileage or cost-per-unit metric."

[322] SCE added that it incorporates "[s]econdary upgrade costs … into total project costs and therefore [the costs are] embedded within the primary per-mile cost metric" and "[v]ariability in secondary scope is addressed during project-level engineering and planning design, and is not normalized independently."[323] In response to SPD's question "Does the per-unit cost differ between primary and secondary line hardening?" SCE responded, "SCE does not maintain separate per-unit cost metrics for primary versus secondary line hardening."[324]

SCE confirmed that it "does not maintain separate per-unit cost metrics for primary versus secondary line hardening." It also stated that secondary line work "is not normalized independently" and that its inclusion in a project "may vary based on regional conditions and project-specific design requirements."[325, 326]

SPD asked how SCE hardens secondary distribution lines when hardening primary distribution lines. For TUG, SCE stated that "[a]ll secondary lines that are in line or attached to TUG scope are to be placed underground where possible." For CC, SCE stated that "[a]ll secondary lines that share the same line path of or are attached to the same targeted primary structures are to be upgraded to the latest standard." SCE also explained that "[i]f secondary lines are being upgraded and during the field visits from Tech Planning the service lines are found to be degraded, then service lines are replaced as necessary."[327] The cost of this secondary and service line work is therefore embedded in SCE's total project cost that informs SCE's benefit-cost analysis. However, SCE does not include service and secondary lines in its risk calculations, saying that risks from these lines "are not explicitly represented within the current POI model."[328] Further, the ranking of circuits for hardening is not informed by risks from secondary and service lines, only primary distribution asset risks.[329] SCE is incorporating the cost of hardening secondary and service lines into its model without incorporating the risk reduction of that hardening in the estimated benefit, a one-sided treatment.

---

[322] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 18(a).

[323] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 18(a).

[324] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 18(b).

[325] SCE response to Data Request Data Request SPD-SCE-2026 RAMP-004, Questions 17, 18, and 19.

[326] SCE response to Data Request Data Request SPD-SCE-2026 RAMP-004, Question 18.

[327] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 20.

[328] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 19(a).

[329] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 19(b).

This one-sided treatment is inconsistent with the same-basis principle SCE articulated elsewhere in its response to the same data request, where SCE addresses questions about its BCR methodology. In response to the question "How does SCE ensure that the BCR reflects the marginal risk reduction of the proposed work?" SCE said for "standard hardening" (e.g., CC, TUG), "wildfire risk reduction benefits and associated costs are limited to the currently unhardened portions of the circuit. Previously hardened segments are excluded from both benefit and cost, as no incremental wildfire risk reduction or additional cost is realized from those segments" to "accurately" reflect "marginal risk reduction attributable to the proposed work.[330] SCE stated that this approach ensures that "the BCR accurately reflects the marginal risk reduction attributable to the proposed work" and "avoids double-counting" previous hardening work.[331] This frames SCE's approach to calculating BCRs as ensuring the numerator and denominator cover the same scope of assets. For secondary and service lines, however, SCE includes the associated cost in the denominator and excludes the associated risk-reduction benefit from the numerator.

Because costs associated with hardening secondary and service lines appear in the numerator of SCE's per-mile unit cost calculation (total project cost) but not the denominator (primary miles), including secondary and service lines in the scope raises the reported cost per primary mile. To the extent this per-mile cost informs the BCR denominator, the ratio pairs a primary-line-only risk-reduction benefit with a cost basis inflated by secondary and service line work whose risk-reduction benefit SCE does not model. This may understate the BCRs of mitigations involving significant work on secondary and service lines. Regarding RRU prioritization, per SCE's data request response, it appears SCE would give the same rank to two RRUs (circuits) with the same primary-line risk, even if one has significant secondary-line risk and the other has no secondary line-risk.[332]

Regarding ignition from vegetation contact on secondary or service lines, SPD notes that in its response to another data request question about SCE's Fire Investigation Preliminary Analysis (FIPA)[333] ignitions for the period 2019 through 2024, SCE provided information indicating that, for that period, roughly half of SCE's vegetation-contact ignitions (47 of 94) occurred on secondary or service lines.[334] At the same time, SCE's Chapter 4 work paper "Wildfire Mitigation Effectiveness" spreadsheet indicates that TUG completely

[330] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 39(a).

[331] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 39(a).

[332] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 19(b).

[333] "FIPA (Fire Investigation Preliminary Analysis) refers to SCE's data collection and investigative process used to document ignition events, including the most likely root cause and the equipment involved. FIPA data is leveraged as an input to subsequent analytical and predictive modeling efforts" per SCE 2026 RAMP Ch. 4, p. 23, footnote 43.

[334] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 26, attachment "SAFARI_SPD-SCE-2026RAMP-004 Question 26.xlsx.

eliminates ignition risk from vegetation contact.[335] SPD pursued more information about this in a data request, asking SCE to explain "why [it] estimates the mitigation effectiveness of targeted undergrounding as 100 percent while the majority of SCE's distribution overhead ignitions related to vegetation contact will not be mitigated by targeted undergrounding."[336] In response, SCE stated that its estimate of 100 percent effectiveness for TUG "applies specifically to the primary conductor facilities included in the TUG mitigation scope" and secondary and service lines "are generally outside the scope of the TUG benefit-cost analysis and mitigation effectiveness methodology."[337]

Stated more simply, SCE's risk model (and thus each RRU) does not include the risk of all components of the circuit, only the risk of the portion SCE models or mitigates (i.e., primary line risk). Where SCE does not plan to underground a primary line, it does not account for the risk of the secondary and service lines on that primary line. In doing so, SCE may remove 100 percent of the risk it is trying to mitigate through TUG, but it does not mitigate 100 percent of its system risk. SCE's assertion that TUG removes all risk of wildfire caused by vegetation contact may mislead the public, including ratepayers, as to the actual residual risk on the system. In fact, TUG removes only the risk SCE modeled. For reference, Pacific Gas and Electric Company (PG&E) explicitly addressed secondary and service line risk, as well as risk from underground lines, also separating HFRA from non-HFRA lines, in its most recent RAMP filing.[338]

The record does not establish SCE's approach to ignitions associated with secondary and service lines. Does SCE include ignitions associated with secondary and service lines in its probability of ignition (POI) calculations and claim credit for reducing that risk when it hardens only the primary line? Or does SCE exclude ignition risk from secondary and service lines entirely from its calculations? Either approach may lead the public, including ratepayers, to believe that mitigated lines are safer than they are.

As SCE's data request responses indicate, SCE combines primary and secondary line hardening costs in a single per-unit cost metric and does not independently normalize the scope of secondary line work. Because the inclusion of secondary lines depends on regional conditions and project-specific design requirements, two projects with the same reported cost per primary-line mile may include substantially different amounts of secondary and service line work. This variability, which SCE does not track or report, reduces the

---

[335] SCE 2026 RAMP Ch. 4 work paper "Wildfire Mitigation Effectiveness," tab "Wildfire Summary," indicates that for "Subdriver/ Consequence Type" "Veg. contact – Distribution" the "Mitigation Effectiveness" for "Targeted Undergrounding" is "100%."

[336] Data Request SPD-SCE-2026RAMP-010, Question 26.

[337] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 26.

[338] Pacific Gas and Electric Company 2024 Risk Assessment and Mitigation Phase Report, Exhibit (PG&E-4) Electric Operations, Chapter 1 Risk Assessment and Mitigation Strategy: Wildfire with PSPS and EPSS, Table 1-3 "Tranche Level Exposure Statistics," p. 1-25 (PDF p. 463) (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf, accessed Aug. 19, 2026).

comparability of per-unit cost and benefit-cost figures across RRUs and complicates any tranche-level evaluation that relies on those figures.

SCE's 2026 RAMP limits its wildfire risk scope to overhead distribution and transmission assets within its HFRA.[339] SPD finds that SCE's data request responses suggest that underground assets and assets outside the HFRA may also warrant inclusion in that scope.[340] Those responses also indicate that secondary and service lines may warrant inclusion.

CPUC Safety Enforcement Division (SED) records identify the Cerritos Fire, which SCE reported to SED in December 2020, as a fire in SCE's territory that burned approximately 200 acres. The Incident Investigation Report notes that the fire involved a "600 V rated triplex cable" and that CAL FIRE collected "approximately 175 feet of the triplex cable and secondary conductors installed between poles" near the ignition site.[341] The investigation's findings point to the involvement of a secondary or service line.

SED records also document the 2017 Nuns Fire in PG&E's territory, which investigators determined involved secondary conductors. The fire caused three fatalities and $179 million in property damage, burned 56,556 acres, and destroyed 1,355 buildings.[342] The investigation found that PG&E had committed the following violation of General Order 95, Rule 35: "Improper prioritization and delay in abating vegetation strain on secondary service conductor."[343] The investigation's findings clearly point to the involvement of a secondary line.

---

339 SCE 2026 RAMP Ch. 4, Table II-4 "Wildfire Risk Scope," p. 24.

340 SCE response to Data Request SPD-SCE-2026RAMP-004, Questions 5(a), 7, and 8.

341 CPUC SED Electric Safety and Reliability Branch Incident Investigation Report for Incident Number E 20201203-01 (June 23, 2022), pp. 1-2 (https://acrobat.adobe.com/link/track?uri=urn%3Aaaid%3Ascds%3AUS%3Aa9b96b5d-849f-319f-98dd-a9c28bf2d971&viewer%21megaVerb=group-discover, accessed Aug. 19, 2026); see the SED Staff Wildfire Investigations web page for more information (https://www.cpuc.ca.gov/industries-and-topics/wildfires/wildfires-staff-investigations, accessed Aug. 19, 2026).

342 CPUC SED Electric Safety and Reliability Branch Incident Investigation Report for Incident Number E20171016-01 (April 30, 2019), pp. 1-2 (https://files.cpuc.ca.gov/I19-06-015/I.19-06-015%20October%202017%20NorCal%20Fires/E20171016-01%20Nuns%20Report%20and%20Attachments.Redacted.pdf, accessed Aug. 19, 2026). CAL FIRE ranks Tubbs Fire fourth in this list and assigns the cause as "Electrical" and CAL FIRE ranks the Valley Fire eighth and assigns the cause as "Electrical."

343 CPUC SED Incident Investigation Report for Incident E20171016-01, p. 2.

Residential electrical equipment (which operates at voltages equivalent to secondary level voltages) caused two of the most destructive wildfires in California history, the Tubbs[344] and Valley[345] fires.[346] SPD cautions against using instances of fires caused by residential electrical equipment to infer a possible fire risk from utility assets, but the lesson remains important: secondary line-level voltages can cause fires. As noted above, PG&E disclosed these risks categories (e.g., non-HFRA, secondary, underground lines) in its most recent RAMP filing.[347]

SPD finds the following about SCE's circuit-level RRU costs and secondary and service lines:

12. SCE's wildfire risk baseline excludes underground assets, assets outside its HFRA, and secondary and service lines. However, its spending estimates and per-mile cost figures include the cost of hardening secondary and service lines. Because SCE defines its RRU as all the portions of a circuit within its HFRA and models risk only for the portion it mitigates, SCE's calculation of the RRU's residual risk reflects the risk SCE intends to mitigate rather than the full risk remaining on the circuit.

13. SCE's benefit-cost analysis treats secondary and service lines asymmetrically: hardening costs are embedded in the spend and per-mile metrics, but ignition risk is excluded from the POI model and circuit rankings. This conflicts with SCE's stated BCR methodology, which requires cost and benefit to cover the same assets. This approach affects both the numerator and denominator of the BCR. Excluding the risk reduction from secondary line work understates the benefits—and therefore the BCRs—of mitigations that include substantial secondary line hardening. Meanwhile, SCE spreads secondary line hardening costs across all units in a region through a blended regional cost per mile, rather than tracking the work included in each unit. As a result, per-mile costs and BCRs are not reliably comparable across RRUs or tranches. In a data request response, SCE conceded "the consequence of an ignition event is not materially dependent on the originating asset type," adding

---

344 CAL FIRE determined the Tubbs Fire was caused by "a private electrical system adjacent to a residential structure" per LA Times, "Private power lines, not PG&E's, caused deadly wine country fire, state says" (Jan. 24, 2019) (https://www.latimes.com/local/lanow/la-me-pge-fire-santa-rosa-20190124-story.html, accessed Aug. 20, 2026).

345 CAL FIRE determined the Valley Fire was caused by "a faulty electrical connection," specifically caused by "a wire at a poorly connected hot tub overheat[ing]," "ignit[ing] dry brush nearby at a home in Cobb town" per CNN, "Faulty hot tub wiring sparked wildfire that killed 4 in California" (Aug. 11, 2016) (https://www.cnn.com/2016/08/11/us/california-valley-fire-faulty-hot-tub/index.html, accessed Aug. 20, 2026).

346 CAL FIRE "Top 20 Most Destructive California Wildfires" (Oct. 9, 2025) (https://34c031f8-c9fd-4018-8c5a-4159cdff6b0d-cdn-endpoint.azureedge.net/-/media/calfire-website/our-impact/fire-statistics/top-20-destructive-ca-wildfires.pdf?rev=737a1073f76947b4a3bfb960b19f44c7&hash=7CA02D30D9BF46A32D5D98BD108BA26A, accessed Aug. 20, 2026).

347 Pacific Gas and Electric Company 2024 Risk Assessment and Mitigation Phase Report, Exhibit (PG&E-4) Electric Operations, Chapter 1 Risk Assessment and Mitigation Strategy: Wildfire with PSPS and EPSS, Table 1-3 "Tranche Level Exposure Statistics," p. 1-25 (PDF p. 463) (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf, accessed Aug. 19, 2026).

"SCE recognizes these as potential contributors to system risk and is actively evaluating enhancements to incorporate these assets into future model iterations."[348] SCE excludes secondary and service lines from its risk modeling based on an asserted difference in ignition likelihood that it has not quantified. Its historical ignition data do not support that rationale: approximately half of recorded vegetation-contact ignitions from 2019-2024 occurred on secondary or service lines.[349, 350]

Risk Drivers

In its risk bow ties, SCE presents four potential leading indicators, or drivers, for wildfire risk and one potential leading indicator for PSPS risk.[351, 352]

Wildfire

- **Contact from object**: This driver represents ignition risk associated with foreign objects contacting energized overhead electrical equipment, resulting in electrical faults that may lead to ignitions and includes sub-drivers addressing risk from contact from animals, balloons, an "other" category capturing otherwise uncategorized items such as "debris, projectiles, or airborne materials," [353] vegetation, and vehicles.[354]
- **Equipment/facility failure**: This driver "represents an ignition probability associated with ignition events initiated by the degradation, malfunction, or structural failure of electrical equipment" not related to a contact from an object.[355] This driver includes sub-drivers addressing components of both distribution and transmission assets, 11 for distribution and 5 for transmission.[356]
- **Wire-to-wire contact**: SCE sometimes refers to this driver as "wire-to-wire contact / contamination."[357] SCE does not describe this driver category further in its RAMP application. In

[348] SCE response to SCE response to Data Request SPD-SCE-2026RAMP-004, Question 19(a).

[349] SCE response to SCE response to Data Request SPD-SCE-2026RAMP-004, Question 19.

[350] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 26, attachment "SAFARI_SPD-SCE-2026RAMP-004 Question 26.xlsx."

[351] SCE 2026 RAMP Ch. 4, Figure II-4 "Risk Bowtie for Wildfire Risk," p. 25.

[352] SCE 2026 RAMP Ch. 4, Figure XI-9 "Risk Bowtie for PSPS Risk," p. 99.

[353] SCE 2026 RAMP Ch. 4, p. 27.

[354] SCE 2026 RAMP Ch. 4, pp. 25-28.

[355] SCE 2026 RAMP Ch. 4, p. 28.

[356] SCE 2026 RAMP Ch. 4, p. 29.

[357] SCE 2026 RAMP Ch. 4, Appendix B "Appendix B - Wildfire and PSPS Drivers and/or Consequences Impacted By Control," Tables 1, 2, 5, 6, 7, 9, 11, 12, 13, 14, 17, 18, 19, 20.

response to a data request, SCE clarified that this driver represents physical contact between multiple wires leading to an ignition event.[358]

- **Other/unknown:** SCE does not describe this driver category further in its RAMP application. In response to a data request, SCE clarified that this driver represents ignition events whose cause could not be determined or that do not belong in the other defined categories.[359]

PSPS

- **Circuit de-energization thresholds met or exceeded**: SCE describes this driver as "the projected forecast of environmental conditions, driven by dry fuels and high winds that meet or exceed SCE's established de-energization thresholds."[360] SCE notes that while historical data inform its de-energization thresholds, historical averages may not be reliable predictors of the future.[361]

Observations and Findings

SPD has no observations or findings on SCE's description of the drivers for these risks.

[358] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 1.

[359] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 1.

[360] SCE 2026 RAMP Ch. 4, p. 99.

[361] SCE 2026 RAMP Ch. 4, p. 99, footnote 89.

Risk Driver Frequencies

SCE provides details on two sets of wildfire drivers in its RAMP application: contact from object and equipment/facility failure. SCE reports 39.6 annualized HFRA ignitions (66.1 percent of all HFRA ignitions) attributed to contact from object[362] and 20.3 annualized HFRA ignitions attributed to equipment/facility failure (33.9 percent of all HFRA ignitions).[363]

SCE reports that it translates modeled ignition likelihoods into ignition event frequency by relying "on historical ignitions from FIPA[364] events associated with its overhead equipment in HFRA between 2019 and 2024."[365] SCE establishes the wildfire event frequency for the RAMP period using the average annual ignition events.[366]

Observations and Findings

Observations and Findings about SCE's Risk Driver Frequency Count

To better understand SCE's risk driver frequencies, SPD asked via a data request that SCE provide SCE's count of HFRA utility-related ignitions for each year from 2019 through 2024 and the annualized ignition frequency in the HFRA for each wildfire risk drivers, broken down by sub-driver.[367] SCE's response did not reconcile with the data SCE provides in its 2026 RAMP application, indicating that equipment/facility failure accounts for about 52.7 annualized HFRA ignitions[368] rather than the 20.3 SCE reports in the RAMP.[369] According to SCE's data request response, the four drivers together account for about 95.2 annualized ignitions; contact from object accounts for about 39.3 annualized HFRA ignitions, about 41.3

362 SCE 2026 RAMP Ch. 4, p. 25.

363 SCE 2026 RAMP Ch. 4, p. 28.

364 "FIPA (Fire Investigation Preliminary Analysis) refers to SCE's data collection and investigative process used to document ignition events, including the most likely root cause and the equipment involved. FIPA data is leveraged as an input to subsequent analytical and predictive modeling efforts" per SCE 2026 RAMP Ch. 4, p. 23, footnote 43.

365 SCE 2026 RAMP Ch. 4, p. 33.

366 SCE 2026 RAMP Ch. 4, p. 33.

367 Data Request SPD-SCE-2026RAMP-004, Question 2.

368 SPD calculation based on SCE Response to SPD-SCE-2026RAMP-004, Question 2, attachment SPD-SCE-2026RAMP-004-02a_20260615.xlsx.

369 SCE 2026 RAMP Ch. 4, p. 28.

percent of the ignitions attributed to these four drivers,[370] much less than the 66.1 percent of all HFRA ignitions SCE reports in its RAMP application.[371]

SPD finds the following about SCE's risk driver frequency count:

14. SCE reports in its RAMP application a significantly different ignition frequency for the equipment/facility failure driver from the frequency it reports for that driver over the same period in the same location (HFRA) in response to a data request from SPD. The annualized HFRA frequency SCE reports for equipment/facility failure in its data request response (52.7) is about 2.6 times higher than the frequency it reports in its RAMP (20.3). SPD is concerned that SCE's POI is calibrated to these frequencies, and POI is incorporated into every wildfire risk mitigation BCR calculation. It is unclear which frequency value for equipment/facility failure informs the 2026 RAMP risk model.

Observations and Findings about SCE's Hardening and the No-Build Baseline

SCE reports that it calculates all BCRs for hardening relative to a "no-build baseline,"[372] "represent[ing] a continuation of existing overhead conditions, including the costs associated with ongoing operations and maintenance (O&M) activities that would continue to be necessary absent the proposed grid hardening solution."[373] Historical risk driver frequency and associated estimated risk, as well as ignition reduction attributable to past hardening, should inform these conditions.

SCE's 2029 no-build baseline should reflect conditions as of 2029, incorporating all relevant risk frequencies and hardening done before that date, including the thousands of miles of overhead line SCE hardened between 2019 and 2025 and the additional miles of overhead line SCE expects to harden between now (2026) and 2029.

---

[370] SPD calculations based on SCE Response to SPD-SCE-2026RAMP-004, Question 2, attachment SPD-SCE-2026RAMP-004-02a_20260615.xlsx.

[371] SCE 2026 RAMP Ch. 4, p. 25.

[372] SPD's preferred definition of "no-build baseline" is as follows: "The No-Build Baseline establishes the current risk profile of the system, incorporating all infrastructure and risk controls that are already funded, approved, or implemented (e.g., existing [vegetation management] and inspection cycles). This baseline serves as the calibrated reference point for determining the marginal (i.e., incremental) value of any single new investment." This definition is per the CPUC Staff White Paper on Benefit Cost Ratio Methodology (April 10, 2026) for CPUC Senate Bill 884 Application 26-02-005 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K545/604545276.PDF, accessed Aug. 20, 2026). This document describes SPD's current preferred approach to calculating BCRs. SPD references this white paper for illustrative purposes only. It is not an authoritative source for BCR requirements for utility RAMP applications.

[373] SCE 2026 RAMP Chapter 2 "Risk Model and BCR Methodology," p. 28.

SPD explored the question of how SCE is incorporating into its wildfire risk model information about hardening on specific circuits it expects to perform between now and 2029 through a data request.[374] In response, SCE indicated that it incorporates into its wildfire risk model expected line hardening for 2026-2028 at the circuit level by "appl[ying] the associated mitigation effectiveness (ME%) to reduce the relevant POI sub-drivers."[375] SPD also asked SCE to explain how it incorporates risk reduction from line hardening into its probability of ignition calculation.[376] In response, SCE explained that it models the POI using 51 underlying sub-drivers, with post-mitigation POI calculated as pre-mitigation POI multiplied by (1 − ME%).[377] This confirms SCE has a methodology for normalizing POI to reflect hardening progress. However, in SCE's response to a separate question, SPD learned that SCE does not apply this normalization to the historical ignition counts that calibrate the baseline, stating that its annual average ignition frequency "reflects a historical average based on observed ignitions over the 2019-2024 period" and that "SCE does not normalize this data to reflect the proportion of unhardened and hardened line miles in service at the time of each ignition."[378]

The system underlying that flat average changed substantially across the calibration window. SCE reports that HFRA bare wire primary distribution mileage declined from 8,778 miles in 2019 to 2,865 miles in 2024, against a static total of 9,274 HFRA overhead distribution circuit miles, from approximately 94.7 percent of the system to approximately 30.9 percent.[379] The 2019 observations therefore describe a mostly unhardened system, while the 2024 observations describe one in which CC and TUG predominate. To illustrate the decline in bare wire over time, Table 1-3 shows SCE's bare wire mileage for 2019-2024. Because SCE calibrates each year's weights equally, the resulting average reflects a system configuration that no longer exists and will not exist in 2029.

SCE's no-build baseline ignition frequency therefore rests on a historical average that does not distinguish between years with materially different levels of hardening already completed. The earlier years of the window, when the system was predominantly bare wire, carry the same weight as the later years, when it was predominantly hardened. Because SCE expects to have completed most of its remaining hardening by 2029, with approximately 880 bare wire miles (about 9.5 percent of the system) implied at the start of the 2029–

[374] Data Request SPD-SCE-2026RAMP-004, Question 4.

[375] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 4.

[376] Data Request SPD-SCE-2026RAMP-004, Question 3.

[377] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 3.

[378] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 28(a).

[379] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 25. In its response, SCE noted "Because total HFRA circuit mileage can marginally change over time for a variety of reasons, SCE is simply taking the 2026 Q1 Quarterly Data Report figure of 9,274 miles of overhead distribution circuitry in high fire and working off of that static total to derive bare mileage figures historically."

2032 period compared with 94.7 percent in 2019,[380] an average anchored to the period 2019-2024 is not a reasonable proxy for 2029 conditions: SCE has not shown that it is. SCE measures every wildfire mitigation BCR against this baseline, with implications for SCE's entire portfolio of mitigations.

Table 1-3. SCE's Primary Distribution Bare Wire Mileage, 2019-2024[381]

Year	Bare Wire Miles
2019	8,778
2020	7,818
2021	6,312
2022	5,077
2023	3,673
2024	2,865

SPD finds the following about SCE's hardening and the no-build baseline:

15. SCE calibrates its 2029 no-build baseline on an historical average not normalized to incorporate completed hardening work. It uses a formula to reduce POI on every circuit where it plans to perform hardening during 2026-2028, with mitigation effectiveness (ME%) incorporated as pre-mitigation POI multiplied by (1 − ME%), but SCE "does not normalize [the historical average based on observed ignitions 2019–2024] to reflect the proportion of unhardened and hardened line miles in service at the time of each ignition." [382] The absence of normalization is therefore a methodological choice, not a data limitation. SPD is particularly concerned about the following:
    a. SCE bases its no-build baseline (against which it calculates risk and risk reduction) on an average from 2019-2024 that assigns equal weight to years with materially different hardening levels. SCE reports HFRA bare wire miles declining from 8,778 miles in 2019 to

[380] SPD calculation from SCE 2026 RAMP Ch. 4, p. 44 (approximately 455 miles of CC and 189 miles of TUG planned for 2029–2032, leaving approximately 236 HFRA circuit miles unhardened), relative to the 9,274-mile static total in SCE's response to Data Request SPD-SCE-2026RAMP-004, Question 25.

[381] SPD calculated CPUC-Reportable HFRA Ignitions (Conditions 2 and 3) summing the values reported for Conditions 2 and 3, distribution and transmission, HFRA, in the SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," "Table Breakdown of Historical Ignitions to Derive Conditional Probability Percentages," p. WP-3; Bare Wire Miles per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 25.

[382] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 28(a).

2,865 in 2024 (or, from approximately 94.7 percent of overhead distribution line miles in the HFRA to 30.9 percent).[383, 384]

b. Because the 2019-2024 ignitions occurred at very different hardening levels, an unweighted average of annual ignitions is not a reasonable proxy for the substantially hardened 2029 system. To the extent the average exceeds the level expected under 2029 conditions, the no-build baseline may overstate 2029 ignition frequency.
c. Overstating ignition frequency in the no-build baseline affects BCRs across SCE's mitigation portfolio, including CC, TUG, REFCL, and other hardening mitigations evaluated against this baseline. Because the baseline sets the reference point against which all mitigation benefits are measured, any overstatement would inflate every estimated risk and likewise every BCR based on that risk.

Consequences

Wildfire

As noted above, SCE defines the risk event for wildfire as an ignition associated with SCE's electrical assets and operation in SCE's HFRA.[385] Here, "ignition" refers specifically to an SCE FIPA[386] ignition and "electrical assets" refers to overhead electrical assets.[387]

SCE estimates potential outcomes and consequences using its Wildfire Integrated Model or WIM (see "Risk Description" for a discussion of improvements to SCE's WIM in its 2026 RAMP).

SCE indicates that ignition consequence values stem from two outcomes: [388, 389]

- **Expected value**: this refers to the expected value of asset-level consequence outputs from WIM.
- **Tail risk 98th percentile**: the 98th percentile refers to the statistical description of an extreme or "tail" risk.

---

[383] SCE response to Data Request SPD-SCE-2026RAMP-004, Question 25.

[384] Percentages of bare wire calculated by SPD using the base number 9,274, taken from "9,274 miles of overhead distribution circuitry in high fire miles of overhead distribution circuitry in high fire" per SCE response to Data Request SPD-SCE-2026RAMP-004, Question 25.

[385] SCE 2026 RAMP Ch. 4, Figure II-4 "Risk Bowtie for Wildfire Risk," p. 25.

[386] "FIPA (Fire Investigation Preliminary Analysis) refers to SCE's data collection and investigative process used to document ignition events, including the most likely root cause and the equipment involved. FIPA data is leveraged as an input to subsequent analytical and predictive modeling efforts" per SCE 2026 RAMP Ch. 4, p. 23, footnote 43.

[387] SCE 2026 RAMP Ch. 4, pp. 33.

[388] SCE 2026 RAMP Ch. 4, Figure II-4 "Risk Bowtie for Wildfire Risk," p. 25.

[389] SCE 2026 RAMP Ch. 4, pp. 33-37.

SCE notes that, in order to better account for tail-risk outcomes in its decision making, it uses "the 98th percentile of the asset-level distribution of outcomes" in scope selection for one of its two alternative mitigation plans for wildfire (discussed below in "Alternatives Analysis").[390]

SCE's WIM estimates consequences for safety, reliability, and financial attributes through a monetized analysis framework. See the earlier section "Evaluation of SCE's Risk Model and Benefit-Cost Ratio Methodology" for more information about SCE's approach to the monetization of these different types of consequences.

SCE describes its WIM in its Wildfire Power Law White Paper,[391] submitted in accordance with the option introduced in the RDF Phase 3 Decision allowing utilities to "present an [a]lternative [a]nalysis regarding tail value" by submitting "a [w]hite [p]aper and related workpapers clearly justifying its approach" in advance of its pre-filing workshop.[392] The Phase 3 Decision identifies the use of capped (or "truncated") power law distributions as a best practice for utility estimates of tail risk values.[393] SCE's white paper presents an alternative to the use of truncated power law distributions to describe the relationship between wildfire size and associated risk.

SCE is aiming to create "more granular distributions of wildfire risk."[394] To this end, SCE updated its WIM by adding inputs from two third-party models, FireSight 8 and RMS 2.0, making a "scaled hybrid wildfire risk model."[395] SCE demonstrates the outputs of its updated WIM by plotting the expected value of each asset for acres burned[396] and buildings destroyed[397] in catastrophic wildfires in its territory, "provid[ing]

---

[390] SCE 2026 RAMP Ch. 2, p. 40.

[391] SCE 2026 RAMP Wildfire Power Law White Paper (Nov. 3, 2025) (SCE Power Law White Paper) (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-ramp-power-law-white-paper_nov-2025.pdf, accessed Aug. 21, 2026). Note that SCE submitted this November 2025 white paper without changes as a RAMP 2026 Chapter 2 work paper ("WP Ch 2 - SCE 2026 RAMP Power Law Whitepaper") on May 27, 2026. Page numbers cited here refer to the original SCE Power Law White Paper.

[392] D. 24-05-064, Appendix A, Row 24, p. A-17.

[393] "Based on the record, we conclude that a truncated power law ensures the best fit of data to the statistical models and will best enable this Commission to ensure that utility wildfire modeling appropriately reflects considerable wildfire tail risks but does not over-estimate these risks." Per D. 24-05-064, p. 55.

[394] SCE Power Law White Paper, p. 29.

[395] SCE Power Law White Paper, p. 31.

[396] SCE Power Law White Paper, Figure V-13 "System-level Distribution of Wildfire Integrated Model (WIM) Power-law fit (log-log plot) at Expected Value (Acres Burned)," p. 44.

[397] SCE Power Law White Paper, Figure V-14 "System-level Distribution of Wildfire Integrated Model (WIM) Power-law fit (log-log plot) at Expected Value (Buildings Destroyed)," p. 45.

illustrative examples of rank order cumulative distribution functions utilizing the 'expected value' at each asset using these new transformed scaled FireSight 8 distributions (i.e., the WIM)."[398]

PSPS

As noted above, SCE defines the PSPS risk event as a de-energization associated with PSPS.[399] SCE indicates de-energization of customers as the only outcome of this risk event and indicates that outcome has safety, reliability, and financial consequences.[400] SCE estimates consequences for each circuit in scope for PSPS.[401] SCE notes that for this assessment "SCE used the expected outcomes and associated consequences based on the historical averages used to derive the probability of de-energization."[402] SCE estimates customer minutes interrupted (CMI) by combining average frequency and duration of PSPS events with circuit-level customer counts (accounting for customer class characteristics).[403] For more on how SCE estimates CMI and social vulnerability factors to estimate safety, reliability, and financial consequences, see "Risk Description" ("Observations About SCE's Use of Customer Minutes Interrupted Estimates"). To estimate the financial consequences of PSPS, SCE uses customer lodging and per diem impacts; to estimate the safety impacts of PSPS, SCE uses fatalities, serious injuries, and community vulnerability impacts.[404]

Wildfire Consequence Conditions (Conditions 1-3)

Most of SCE's reported ignitions do not become catastrophic. SCE reported 50 ignitions in 2024, but 34 of them burned less than 0.25 acres.[405] To address the different kinds of ignitions in its territory, SCE breaks its ignitions into three consequence categories, Conditions 1, 2, and 3, "based on conditional probabilities of historical ignitions."[406] They are defined as follows: [407]

- Condition 1: Smallest consequence condition, causing "fires with no propagation," meaning "those that are not CPUC Reportable, or did not spread beyond the pole."

---

[398] SCE Power Law White Paper, p. 43.

[399] SCE 2026 RAMP Ch. 4, Figure XI-9 "Risk Bowtie for PSPS Risk," p. 99.

[400] SCE 2026 RAMP Ch. 4, Figure XI-9 "Risk Bowtie for PSPS Risk," p. 99.

[401] SCE 2026 RAMP Ch. 4, p. 100.

[402] SCE 2026 RAMP Ch. 4, p. 100, footnote 91.

[403] SCE 2026 RAMP Ch. 4, p. 100.

[404] SCE 2026 RAMP Ch. 4, p. 101.

[405] SCE 2024 Fire Incident Data Collection Report (download from the CPUC website) (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/reports/fire-incidents/sce-2024-fire-incident-data-collection-report.xlsx, accessed Aug. 24, 2026).

[406] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-2.

[407] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-2.

    - The consequence calculation includes a financial consequence value based on pole replacement but no safety consequences.
- Condition 2: "[F]ires with propagation, but no structures impacted," meaning "those that are CPUC Reportable but did not occur under sufficiently high fuel conditions."
    - The consequence calculation includes the number of acres burned as modeled by SCE's WIM, but no safety consequences.
- Condition 3: Largest consequence condition, causing "fires with propagation and structures impacted," meaning "those that are CPUC Reportable and occurred under sufficiently high fuel conditions or [are] at least 200 acres" (i.e., fires that meet "the condition as an ESIR").[408]
    - The consequence calculation includes fatalities, structures burned, and acres burned, as modeled by SCE's WIM.

SCE predicts its total consequence by multiplying the predicted consequence of the three conditions by a weighted average.[409] The weights are based on the percentage of ignitions meeting each condition out of the total between 2020 and 2024.[410] SCE then multiplies the consequence value by the probability of ignition to derive wildfire risk, using different weights for the distribution and transmission sides of its system.

For distribution, SCE uses the formula:
WF Risk = POI × [(80% × Cons1) + (11%×Cons2) + (9%×Cons3)][411, 412]

For transmission, SCE uses the formula:
WF Risk = POI × [(58% × Cons1) + (25%×Cons2) + (17%×Cons3)][413]

---

[408] SPD understands fires that meet "the condition as an ESIR" to mean fires that meet the criteria for an ESIR. The term ESIR is written out as "ESOC Significant Incident Report" per SCE 2026 RAMP Chapter 12 "Physical Security," p. 60. ESOC stands for Edison Security Operations Center per Southern California Edison Company's (U 338-E) Final Distribution Security Plan Report of Priority Distribution Facilities to the California Public Utilities Commission Pursuant to Decision 19-01-018, p. 16 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/southern-california-edison-final-distribution-security-plan-report_071221.pdf, accessed Aug. 24, 2026). Alternatively, outside the RAMP, SCE writes out ESIR "Electric Safety Incident Report:" there are numerous documents titled "Electric Safety Incident Report" in the Edison International Southern California Wildfires Document Library (https://www.edison.com/investors/southern-california-wildfires/document-library, accessed Aug. 25, 2026). One such report is the SCE ESIR Additional Information re: Pauba Fire in which ESIR is written out "Electric Safety Incident Report" (https://download.edison.com/406/files/202407/Pauba%20Fire%20ESIR%20Additional%20Information.pdf, accessed Aug. 25, 2026).

[409] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-2.

[410] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-3.

[411] SCE response to Data Request SPD-SCE-2026RAMP-006, Question 4.

[412] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-2.

[413] SCE response to Data Request SPD-SCE-2026RAMP-006, Question 4.

Observations and Findings

Consequence estimates depend on SCE's WIM and its inputs, including SCE's POI estimates and definitions of "Consequence Conditions." SPD's observations and findings about these components follow SPD's observations and findings about SCE's consequence conditions.

Observations and Findings about SCE's Consequence Conditions

When SPD looked more closely at the five Condition 3 ignitions associated with structures damaged or destroyed in the spreadsheet SCE submitted with a data request response, SPD observed that SCE included at least one ignition with a cause other than electric facilities, but which SCE attributed to the distribution system.[414] SCE's response to a data request from the Mussey Grade Road Alliance (MGRA) confirmed the identity of this fire as the Mountain Fire,[415] which was caused by the remains of "a tractor fire that occurred Oct. 30, 2024," specifically "hot debris from the remains of one of the tractor's tires" that became dislodged by "extreme winds."[416] SCE was required to report this fire to the CPUC because there was "a complaint alleging that its electric facilities may have ignited the Mountain Fire; the incident is therefore allegedly attributable to utility facilities."[417] In SCE's response to MGRA's data request, SCE clarified it attributed this fire to the distribution system because when SCE submitted its Electric Safety Incident Report[418] at the time of the fire, not knowing its cause, it found that "[o]ne of the circuits identified as a potential suspect [was] at the Distribution level."[419]

SCE's inclusion of at least one Condition 3 fire not caused by electric facilities in its calculations calls into question how it computes the relative frequency of Condition 1, Condition 2, and Condition 3 events. Including the Mountain Fire in its calculations may raise the conditional probability of Condition 3 events for distribution (relative to not including the Mountain Fire) and lower it for transmission (relative to including the Mountain Fire), given the relatively low number of Condition 3 events.

As shown in Table 1-4, SPD calculates that SCE attributes risk to Condition 1 ignitions at about 5 percent, to Condition 2 ignitions at about 6.5 percent, and to Condition 3 ignitions at about 88 percent. The weights SCE applies to different consequence conditions for ignitions are critical to the final risk calculation because

---

[414] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 38, attachment "38_spd_sce_2026ramp_010_q38_condition3_data.csv," "Event_ID" 14358, "Pole_Type" Distribution.

[415] SCE response to Data Request MGRA-SCE-003, Question 4(a).

[416] Ventura County Fire Department News Release: Mountain Fire Determination of Cause (November 7, 2025) (https://www.ci.camarillo.ca.us/news_detail_T2_R266.php, accessed Aug. 25, 2026).

[417] SCE Electric Safety Incident Report re: Mountain Fire (Nov. 12, 2024) (https://download.edison.com/406/files/202411/esir-20241112-mountain-fire.pdf, accessed Aug. 25, 2026).

[418] SCE Electric Safety Incident Report re: Mountain Fire (Nov. 12, 2024) (https://download.edison.com/406/files/202411/esir-20241112-mountain-fire.pdf, accessed Aug. 25, 2026).

[419] SCE response to Data Request MGRA-SCE-003, Question 4(b).

SCE estimates that only 9 percent of ignitions are Condition 3, but attributes about 88 percent of total risk to Condition 3.

Table 1-4. Total Risk (LoRE x CoRE) by Consequence Condition, Beginning of 2029 ($000s)[420]

Condition	LoRE	LORE x CoRE for Safety	LORE x CoRE for Reliability	LORE x CoRE for Financial	Total Risk: LoRE x CoRE for All Attributes	Condition Total Risk / Total Risk
Condition 1	58.5	$0	$296,888	$64,741	$361,628.28	5.2%
Condition 2	13.3	$0	$67,295	$388,445	$455,739.18	6.5%
Condition 3	6.2	$110,682	$31,668	$6,020,893	$6,163,242.54	88.3%
Total	**78**	**$110,682**	**$395,850**	**$6,474,078**	**$6,980,610.00**	**100.0%**

In its data request responses where it provided information on its Condition 3 ignitions, SCE reported "Event_ID, Date, Condition, Fire Acres, Structures Damaged, and Structures Destroyed for the ignitions that SCE classifies under condition 3" [421] and then added an indication for each ignition whether it took place in the HFRA or outside the HFRA and whether it involved distribution or transmission lines.[422]

SPD observed that SCE included in its initial list of Condition 3 ignitions 133 ignitions with no structures damaged, no structures destroyed, and less than 200 acres burned.[423] In another data request on the definition of Condition 3 ignitions, SCE underlined, "Condition 3 represents ignitions that happen during high fire weather conditions that may result in structures damaged or destroyed."[424] This points to SCE's Condition 3 ignitions definition from the "Conditional Probability of Ignition Assumptions" work paper (bold added): "fires with propagation and structures impacted are those that are CPUC Reportable and

[420] SPD calculation applying the Condition 1-3 breakdown percentages provided in SCE's response to Data Request SPD-SCE-2026RAMP-006, Question 14, Table B "Breakdown of Risk Score for Wildfire Risk for Work Paper Conditions 1-3"), to the wildfire risk score totals for the beginning of 2029 from SCE 2026 RAMP Ch. 4, Table I-2, "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk," p. 22.

[421] SCE response to Data Request SPD-SCE-2026RAMP-006, Question 16, attachment "SPD_SCE_2026RAMP_006_16.xlsx."

[422] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 38, attachment "38_spd_sce_2026ramp_010_q38_condition3_data.csv."

[423] SCE response to Data Request SPD-SCE-2026RAMP-006, Question 16, attachment "SPD_SCE_2026RAMP_006_16.xlsx."

[424] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 42(a).

occurred under sufficiently high fuel conditions or is at least 200 acres." [425] SCE doesn't provide thresholds to define "high fire weather conditions that may result in structures damaged or destroyed" or "sufficiently high fuel conditions."

SCE only reports structures destroyed for five of the 103 HFRA ignitions that SCE classified under Condition 3.[426] SCE therefore classified most of the ignitions in SCE's list Condition 3 because they occurred during high fire weather conditions rather than because they impacted structures.[427]

The result is a mismatch between how SCE defines Condition 3 and how often SCE applies its consequence. SPD computed the financial consequence for each HFRA ignition using SCE's Condition 3 formula and found 71 of 103 HFRA ignitions carry a consequence of less than $1,000.[428] For comparison purposes, in response to a data request asking SCE to provide sample calculation showing how SCE uses WIM with SCE's wildfire risk equation to calculate the risk for each consequence type, SCE indicated that its model estimates the cost per acre restored at $2,500 and the cost per acre suppressed at $800, so SPD calculates SCE's total cost for the loss of one acre at $3,300.[429] This means SCE estimates the financial loss for 71 of the fires it classified under Condition 3 as below the value of one acre lost.[430] By contrast, SCE's model assigns Condition 3 a financial consequence of approximately $971 million per event ($6.02 billion in annualized Condition 3 financial risk divided by a LoRE of 6.2 events) (see Table 1-5). SCE's definition of a Condition 3 ignition is therefore not aligned with SCE's modeling of Condition 3 consequence. SPD observes a similar issue with Condition 2.

In its response to a data request question about the classification of Condition 3 ignitions, SCE stated, "SCE's classification framework seeks to characterize wildfire consequence potential rather than relying exclusively on realized historical outcomes. Historical wildfire consequences are highly skewed, with structure impacts and associated financial consequences concentrated in a relatively small number of tail-risk events."[431] SPD does not dispute that a consequence model should reflect potential outcomes, not just historical outcomes; SPD's concern is about the frequency with which SCE is assigning Condition 3 to ignitions, not with the tail value itself. SCE applies a consequence profile calibrated to catastrophic, structure-destroying events to approximately six events per year (the Condition 3 LoRE of 6.2), because the

---

425 SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-2.

426 SCE response to Data Request SPD-SCE-2026RAMP-010, Question 38, attachment "38_spd_sce_2026ramp_010_q38_condition3_data.csv."

427 SCE response to Data Request SPD-SCE-2026RAMP-010, Question 42(a).

428 SPD calculations based on SCE response to Data Request SPD-SCE-2026RAMP-010, Question 38, attachment "38_spd_sce_2026ramp_010_q38_condition3_data.csv."

429 SCE response to Data Request SPD-SCE-2026RAMP-006, Question 9.

430 SCE response to Data Request SPD-SCE-2026RAMP-010, Question 38, attachment "38_spd_sce_2026ramp_010_q38_condition3_data.csv."

431 SCE response to Data Request SPD-SCE-2026RAMP-010, Question 42(a).

Condition 3 frequency is anchored to how often ignitions occur in high fire weather conditions. Historically, however, SCE reports only 10 utility-involved ignition associated with destroyed structures between 2016 and 2025, or one per year.[432] SCE therefore applies the tail consequence roughly six times as often as structure-destroying events have actually occurred, because Condition 3 counts high-fire-weather occurrence rather than structure-impact likelihood.

SPD finds the following about SCE's consequence conditions:

16. SCE's classification of each ignition into consequence conditions does not appear aligned with the consequence its model predicts. The misalignment of the historical consequence of ignitions used to calibrate the consequence values with the definition of consequence conditions SCE uses to classify ignitions may lead SCE to over- or underestimate an ignition's risk.
    a. SCE provided a list of Condition 3 ignitions that included 103 HFRA ignitions, with only 5 associated with structures destroyed.
    b. Looking at the list SCE provided for 2020-2024, SPD's calculation of financial consequences for SCE's historical Condition 3 ignitions in the HFRA were much less than the consequence value that SCE assigns using its WIM.
    c. Because the Condition 3 frequency is anchored to how often ignitions occur in high fire weather conditions rather than to structure-impact likelihood, SCE applies a structure-loss consequence profile to approximately six ignitions per year (the Condition 3 LoRE of 6.2); historically only about one ignition per year has destroyed structures.
    d. SCE doesn't justify its inclusion of at least one ignition with a cause other than electric facilities in its list of Condition 3 ignitions and its assignment of that ignition to the distribution system. SPD is unsure how many ignitions with causes other than electric facilities SCE used to inform its probability calculations. Using such ignitions to calculate conditional probability may skew the probability attributed to transmission versus distribution ignitions, and the relative frequency of Condition 1, Condition 2, and Condition 3 ignitions.

[432] SPD calculates that SCE had an average of one utility-involved ignition associated with destroyed structures per year based on SCE 2026 RAMP Ch. 4 work paper "Wildfire and PSPS Consequence Assumptions," Table W-3 "Safety: Underlying Data used to Derive Wildfire Fatalities and Serious Injury Estimates - Catastrophic Utility involved Wildfires in SCE's Service Territory," p. WP-8.

Observations and Findings about SCE's Calibration of its POI Model: FIPA vs. CPUC-Reportable Ignitions

SCE states that "[c]urrent probability of ignition is calibrated to all historical ignitions over the past 5 years."[433] SCE uses its FIPA ignitions to calibrate its POI model, scaling them so the number of ignitions it predicts for each driver matches the observed FIPA counts (e.g., if there were 10 FIPA transformer-caused ignitions, its POI model predicts 10 transformer-caused ignitions).[434, 435]

Calibration is necessary because machine-learning POI models often predict the relative risk of ignition rather than the absolute number of ignitions. Utilities therefore scale the model's outputs so that the total number of ignitions it predicts matches the number actually observed.[436, 437, 438] SCE's calibration choice is therefore central to the risk context in two ways. First, it sets the overall level of predicted risk; a mis-calibrated model could vastly over- or under-predict the risk on SCE's system in total. Second, it sets the relative risk among drivers. Because risk reduction is calculated based on a mitigation's effectiveness against each ignition driver, an over-weighted driver could lead SCE to choose one mitigation over another, not because it delivers the most risk reduction, but because it is effective against the driver the model has overstated.[439]

In this context, SPD notes two divergences between the FIPA and CPUC-reportable ignition data, the two ignition datasets SCE has placed in the record: the first concerns the trend and the absolute number of ignitions, the second concerns the relative mix of ignitions across drivers. The ignition counts SCE provided in response to an SPD data request and the CPUC-reportable counts from the Chapter 4 work paper "Conditional Probability of Ignition Assumptions" cover the same territory and years, but the numbers

---

433 SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-1.

434 SCE 2026 RAMP Ch. 4, pp. 33–34.

435 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 24.

436 PG&E Wildfire Distribution Risk Model Version 4 (2024), pp.1 and 11 (https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/wildfire-distribution-risk-model-documentation-v4.pdf, accessed Aug. 28, 2026).

437 SCE response to Data Request SPD-SCE-2026RAMP-004, Question 28(a).

438 SCE response to Data Request SPD-SCE-2026RAMP-006, Question 8.

439 As a simplified illustration, a utility might find that transformers in service over 10 years are more likely to have ignitions and build a model treating every such transformer as an ignition. If 100 transformers are over 10 years old, but only 10 transformer-caused ignitions occur each year, the model over-predicts ignitions (100 vs. 10). While this may still be useful for ranking the riskiest units, calibrating the POI to 10 total corrects the count. Left uncalibrated, the utility could (1) prioritize replacing all transformers to "address" 100 ignitions while really mitigating only about 10 properly calibrated ignitions; (2) believe its total risk is far higher than it is; or (3) the utility could mistakenly prioritize inspections of transformers when addressing another driver would have more impact.

move in opposite directions (see Table 1-5).[440, 441] Based on those sources, over 2020-2024, SPD calculates that the FIPA count increases by approximately 109 percent while the CPUC-reportable series declines by approximately 12 percent.

Table 1-5. FIPA and CPUC-Reportable Ignitions

Year	FIPA HFRA Ignitions[442]	CPUC-Reportable HFRA Ignitions (Conditions 2 and 3) [443]
2020	76	57
2021	77	51
2022	101	45
2023	110	19
2024	159	50

One difference that might explain this divergence is that these two datasets are based on different sets of events: the FIPA dataset includes ignitions regardless of spread,[444] while the CPUC-reportable ignitions dataset includes only ignitions that spread more than one meter.[445] SPD speculates that system hardening might affect the CPUC-reportable ignition count but not the FIPA count.

[440] SPD's calculation summing all sub-drivers by year to get FIPA HFRA ignition count per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 2(a), attachment "SPD-SCE-2026RAMP-004-02a_20260615.xlsx." SCE's response does not identify the underlying dataset. SPD understands the counts to be FIPA-based because SCE states that it calibrates its POI model to all 2019-2024 FIPA ignitions and sets ignition targets by driver, per SCE response to Data Request SPD-SCE-2026RAMP-006, Question 8(b) and (d); SCE response to Data Request SPD-SCE-2026RAMP-004, Question 24; and the Question 2(a) attachment's (cited above) report counts and a 2019-2024 annualized frequency by sub-driver.

[441] SPD's calculation summing distribution and transmission HFRA counts to get CPUC-reportable HFRA ignition count for Conditions 2 and 3 per SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-3.

[442] SPD's calculation summing all sub-drivers by year to get FIPA HFRA ignition count per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 2(a), attachment "SPD-SCE-2026RAMP-004-02a_20260615.xlsx."

[443] SPD's calculation summing distribution and transmission HFRA counts to get CPUC-reportable HFRA ignition count for Conditions 2 and 3 per SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-3

[444] SCE response to Data Request SPD-SCE-2026RAMP-004, Questions 26 and 27.

[445] For the criteria for reporting ignitions to the CPUC, see the CPUC website Wildfire and Wildfire Safety, "Fire Ignition Data" (https://www.cpuc.ca.gov/industries-and-topics/wildfires, accessed Aug. 24, 2026).

To explore this question further, during SCE's post-filing RAMP workshop, SPD asked SCE the difference between the FIPA and CPUC-reportable ignition counts.[446] SCE indicated that the FIPA count is more inclusive, and SPD asked "if … an insulator was contaminated, it would be included for instance?" SCE responded, "That's right," adding "there are very few ignitions and we want to have a more inclusive data set, so we can have more variables to train our model on." SPD continued to ask why the FIPA count increased while the CPUC-reportable ignition count went down. SCE responded, "observation bias … because we're paying attention to it, we're seeing more of them."[447]

SPD followed up on this discussion with a data request, asking, "Given that SCE's ignition risk appears inflated by the FIPA ignition count being used for calibration, how is SCE taking into account the impact of the observation bias baked into the FIPA ignition count to accurately measure the effectiveness of its wildfire mitigation efforts from 2019 to 2024?"[448] SCE responded that it disputes that the "wildfire ignition risk appears inflated" as a result of calibrating its model to the FIPA ignition count, and "SCE considers the FIPA dataset to be more appropriate for calibration of its asset-level Probability of Ignition (POI) model because it is better aligned with the risk event being modeled and provides a larger and more detailed set of observations for model development and calibration."[449] SCE continued to add that it believes the increasing FIPA ignition trend is not all due to observation bias, stating that "the observed trend likely reflects a combination of improved detection and documentation practices, as well as potential changes in underlying ignition conditions and risk drivers."[450] It clarified that it cannot "reliably quantify the relative contribution of each effect." [451]

In an earlier data request, SPD asked about the use of the FIPA ignition dataset to calibrate SCE's POI model, and SCE acknowledged in its response that it has made "many enhancements" to its ignition-investigation and documentation practices since SCE started its FIPA processes in 2019.[452] Because the calibration anchor is a single unweighted mean of annual ignition counts for 2019 through 2024—a period spanning this change in detection practice—it is not a reliable basis for projecting 2029 system conditions.

Based on SCE's response that improved detection partially drives the upward trend in FIPA ignition counts, SPD finds it probable that SCE would have recorded more ignitions in 2020 if practices used in 2023 and 2024 had been applied. As a result, SCE's choice to calibrate the POI to FIPA ignitions may not be

---

[446] Recording of SCE's Post-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop (June 25, 2026), time stamp 3:46:56 to 3:49:06 (https://www.youtube.com/watch?v=3nRf-1HL2Q4, accessed Aug. 24, 2026).

[447] Recording of SCE's Post-Filing RAMP Workshop, time stamp 3:46:56 to 3:49:06.

[448] Data Request SPD-SCE-2026RAMP-010, Question 13.

[449] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 13.

[450] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 13.

[451] SCE response to Data Request SPD-SCE-2026RAMP-010, Question 13.

[452] SCE response to Data Request SPD-SCE-2026RAMP-006, Question 7.

representative of the number of ignitions expected to occur in future years. Therefore, conclusions drawn from the POI model about mitigation effectiveness and the total risk may be inaccurate.

SCE's choice to use FIPA ignitions to calibrate its POI model also impacts the relative risk of drivers, since the data are not consistent across drivers. For example, the number of FIPA ignitions caused by the transformer driver increased from 2 in 2019 (4 percent of the FIPA ignition total) to 36 in 2024 (23 percent of the FIPA ignition total).[453] SPD observes this pattern, where the number of FIPA ignitions for specific drivers both (1) increases in magnitude and (2) changes as a percentage of the total number of ignitions, across multiple drivers. Because the relative composition of FIPA counts shifts over time and is partially attributable to observation bias, SPD does not believe the relative POI among ignition drivers is properly calibrated. This kind of miscalibration could lead SCE to prioritize one mitigation over another because of observation bias rather than actual risk-reduction effectiveness.

Additionally, the prevalence of certain CPUC-reportable ignition drivers differs substantially from those of the FIPA ignition drivers. For instance, SCE reported one CPUC-reportable transformer-caused overhead ignition in 2024 out of 44 ignitions in the HFTD (2.3 percent of the total number of CPUC-reportable ignitions in the HFTD),[454] compared to 36 transformer-caused FIPA ignitions in SCE's HFRA out of 159 total FIPA HFRA ignitions (23 percent).[455] The importance of the transformer ignition driver in mitigation decisions therefore differs by calibration method, since FIPA ignitions imply substantially more transformer ignitions, both in total and as a percentage, than CPUC-reportable ignitions. This could make a mitigation such as TUG appear to mitigate more risk than CC due to the calibration choice rather than each mitigation's inherent effectiveness. Neither SCE's RAMP filing nor its data request responses address how mitigation effectiveness or the resulting mitigation ranking would differ if the POI model were calibrated to CPUC-reportable rather than FIPA ignitions.

SPD believes the divergence in prevalence of certain drivers in the two datasets reflects the fact that some FIPA ignitions are less likely to spread (given that there is no spread extent criterion for the reporting of FIPA ignitions while there is for CPUC-reportable ignitions). In response to SPD's data request on this topic, SCE reported, "SCE accounts for differences among ignition drivers through the POI estimate, while

---

[453] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 2, attachment "SPD-SCE-2026RAMP-004-02a_20260615.xlsx."

[454] 2024 ignition count and SPD calculation of the share of total ignitions per data from the SCE 2024 Fire Incident Data Collection Report (download from the CPUC website) (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/reports/fire-incidents/sce-2024-fire-incident-data-collection-report.xlsx, accessed Aug. 24, 2026). Note that the CPUC-reportable ignitions report designates each ignition as being in the CPUC-defined HFTD or not: it does not take into account the boundaries of the SCE-defined HFRA, which encompasses the HFTD but also other areas it calls SOB322 locations. For more on the definition of the HFRA, see SCE 2026 RAMP Ch. 4, Table II-4 "Wildfire Risk Scope," p. 24. SPD chose to use the HFTD for this comparison because the CPUC-reportable ignitions data, which use HFTD, not HFRA, are publicly available. SPD's understanding is that the substantive discussion of this analysis would not change if the HFRA was used.

[455] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 2, attachment "SPD-SCE-2026RAMP-004-02a_20260615.xlsx."

applying the conditional consequence probabilities consistently across established ignitions."[456] In the same data request response, SCE reports, "SCE's approach separates the likelihood of an ignition from the potential outcome if an ignition occurs" and "SCE does not apply a condition [i.e., severity] split by ignition subdrivers," so SCE does not assign higher or lower probabilities of spread based on the driver and SCE's consequence model does not correct for driver-specific differences in spread propensity.[457] By using FIPA ignitions to calibrate its POI model, SCE may overemphasize certain drivers that are inherently less likely to spread and therefore less risky. A related question the record does not resolve is whether the drivers more prevalent in the FIPA ignition dataset are also less likely to fail during the high-wind conditions associated with California's most catastrophic wildfires. If so, calibrating the POI model to FIPA ignition counts could shift mitigation selection toward drivers that appear frequent but contribute less to the high-wind, high-spread tail.

SPD finds the following about SCE's calibration of its POI model using its FIPA ignition dataset:

17. SCE's FIPA HFRA ignition count over 2020-2024 rises about 109 percent[458] while SCE's HFRA CPUC-reportable HFRA ignition count declines about 12 percent over the same period.[459] The ratio between the two data sets ranges from 1.3 to 5.8.
    a. These two datasets are based on different sets of events. The FIPA dataset reflects changes in SCE's recording, classification, or screening practices rather than ignition frequency over the observation period. SCE indicated that observation bias affects the number of FIPA ignitions used to calibrate the model. As a result, the FIPA dataset is not reliable to use for calibration.
    b. If SCE's practices for tracking ignitions in its FIPA record were not consistent across 2019-2024, a historical average of annual ignition counts is not a valid calibration anchor, regardless of hardening status, because it averages across a period in which the basis of measurement changed.
    c. SCE's use of FIPA ignitions may be distorting the risk on the system by increasing the number of ignitions related to drivers which historically are less likely to cause CPUC-reportable ignitions. Calibrating the POI model using FIPA ignition counts may therefore overemphasize drivers inherently less likely to lead to ignition spread while underweighting wind-related drivers more likely to fail in the high-wind conditions associated with many of California's catastrophic wildfires.

[456] SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 18(b).

[457] SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 18(a) and (b).

[458] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 2, attachment "SPD-SCE-2026RAMP-004-02a_20260615.xlsx."

[459] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-3.

Regarding WIM

SPD understands that SCE's WIM rescales asset-level FireSight 8 (L8 hexagon) values toward the coarser RMS 2.0 (L7 hexagon) distribution using a nonlinear scaling operator, then truncates the result at a maxima derived from the RMS 2.0 data so consequences "would not be overstated."[460] To the extent SCE has disclosed the operator, SPD notes that the truncation ceiling is the RMS 2.0 hexagon maximum, not its expected value. An individual asset can therefore be scaled toward that maximum, and SCE has not demonstrated that the aggregate of the scaled asset-level expected values reconciles to (or does not exceed) the RMS 2.0 hexagon-level expected value SCE intends the scaling to respect.

SPD did not observe justification that WIM predicts consequence. SPD reviewed the fires SCE plotted for reference in Figures V-13 and V-14, but considers these as reference points, not validation of the model, because SCE did not indicate how the fires related to the assets being plotted. For instance, the plotted fires would be uninformative if WIM predicted assets near the ignition sources of these fires to be in areas of low consequence. SCE's Power Law White Paper identified perceived weaknesses of a historic-based power law modeling approach but did not demonstrate that its WIM addressed these weaknesses.[461] SCE also did not show that the consequence predicted with WIM (in combination with likelihood predictions) results in realistic absolute risk values. Notably, the truncated power law standard SCE discusses was introduced by the RDF Phase 3 Decision, under which a utility is expected to conduct "multiple tests of truncation values to determine goodness of fit to existing data."[462] SCE's Power Law White Paper acknowledges that standard but does not present goodness-of-fit or sensitivity results demonstrating that WIM satisfies it.[463]

To provide a reference for SCE's absolute risk values, SPD applied SCE's own consequence methodology to catastrophic utility-involved wildfires in SCE's territory over 2016-2025, computing an average annual financial consequence of approximately $3.1 billion,[464] and compared it to SCE's modeled 2029 financial

---

460 Quote per SCE Power Law White Paper, p. 40; description of the rescaling and truncation process from SCE Power Law White Paper, "Step 3," pp. 39-41, also p. 38 footnote 96 and p. 39, footnote 98.

461 SCE Power Law White Paper, Part IV, pp. 9-28.

462 D.24-05-064, Appendix A, Row 24, pp. A-15.

463 SCE Power Law White Paper, pp. 1-2.

464 SPD calculation (average annual financial consequence 2016-2025 at ~~$5726,531,250~~ $3,118,885,260) presented in "Attachment 1 – DR10 Table 1, Computed Financial Consequence of Wildfires," to SCE response to Data Request SPD-SCE-2026 RAMP-010 applying SCE's consequence methodology to the catastrophic utility-involved wildfires in SCE 2026 RAMP Ch. 4 work paper "Wildfire and PSPS Consequence Assumptions," Table W-3 "Safety: Underlying Data used to Derive Wildfire Fatalities and Serious Injury Estimates - Catastrophic Utility involved Wildfires in SCE's Service Territory," p. WP-8. For more information, see SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 20. The number that has been struck out represents a typo in the original data request: SPD provides the correct number beside it.

attribute loss of approximately $6.5 billion (78 ignitions × $83,001,000).[465] The modeled value is more than double the historical average, even though SCE has made substantial expenditures (e.g., the CC program) to reduce risk over that period. SPD recognizes this is not a like-for-like statistical test: the ten-year average is itself driven by a small number of extreme events (notably the 2017 Thomas, 2018 Woolsey, and 2025 Eaton fires), it is not an expected-value benchmark, and it predates most of the hardening; the same methodology applied to all territory fires yields a higher figure (about $5.2 billion).[466] SCE likewise cautioned against comparing historical fires to future predictions.[467] Nonetheless, SPD believes the proximity of the modeled value to the historical average is a sufficient basis to request additional justification for WIM.

SCE stated, "SCE's primary validation efforts focused on evaluating whether the underlying modeled consequence distributions reasonably reflect observed wildfire behavior and consequence patterns. Consequently, SCE does not view comparisons between monetized outputs and historical realized losses, by themselves, as the appropriate method for validating model performance."[468] However, SCE uses the RMS 2.0 model as part of the WIM, and SCE's own Power Law White Paper states that the RMS 2.0 outputs are "calibrated through the RMS Industry Exposure Database (IED), which itself is derived from known insured losses." [469] SCE therefore relies on a model calibrated to historical realized losses while asserting that comparison to historical losses is not an appropriate validation method. SPD has also observed partial model validations from other utilities such as Pacific Gas and Electric Company (PG&E) and San Diego

[465] SPD calculation from SCE 2026 RAMP Ch. 4, Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk," p. 22 (78 ignitions × $83,001,000 = approximately $6.5 billion modeled 2029 financial attribute loss). For more information, see SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 20.

[466] SPD calculation (average annual financial consequence of approximately ~~$9.4 billion~~ $5.2 billion) applying the same methodology to all wildfires in SCE's territory listed in the SCE 2026 RAMP Wildfire Power Law White Paper; the calculation is set out in Data Request SPD-SCE-2026 RAMP-010, Question 20. The ~~$5.7 billion~~ $3.2 billion utility-involved figure is the more relevant comparator for SCE-caused wildfire risk; the $5.2 billion all-territory figure is noted because it bounds the comparison on the other side (SCE's modeled value falls approximately 31 percent below it). The numbers that have been struck out represent typos in the original data request: SPD provides the correct numbers beside them.

[467] SCE Power Law White Paper, pp. 1 and 28.

[468] SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 20.

[469] SCE Power Law White Paper, p. 35, also p. 35, footnote 89 on the RMS Industry Exposure Database.

Gas & Electric Company (SDG&E).[470, 471] Note, SPD is not endorsing these specific validations but presents these partial model validations as evidence that other industry participants are actively attempting to address model validation.

SPD finds the following about SCE's WIM:

18. SCE updated its WIM by adding inputs from two third-party models, FireSight 8 and RMS 2.0, scaling asset-level values toward the coarser RMS 2.0 distribution and truncating at the RMS 2.0 hexagon maximum rather than its expected value. SCE has not demonstrated that the aggregate of the scaled asset-level expected values reconciles to, and does not exceed, the RMS 2.0 hexagon-level expected value SCE intends the scaling to respect.

19. SCE has not validated that its WIM is predictive of consequence and its stated validation position is internally inconsistent. SCE asserts that comparison to historical realized losses is not an appropriate validation method, yet WIM's consequence engine depends on RMS 2.0, which SCE's own Power Law White Paper states is calibrated to historical insured losses — a historical-loss dependency SCE relies on while rejecting historical-loss comparison as validation. SCE also acknowledges the RDF Phase 3 Decision goodness-of-fit standard for truncated power law modeling but does not present goodness-of-fit or sensitivity results demonstrating that WIM satisfies it. Separately, SCE's modeled 2029 financial risk (about $6.5 billion) is more than double the ten-year historical average of utility-involved wildfire losses (about $3.2 billion), despite SCE's substantial hardening expenditure over that period. Specifically, SPD did not find that SCE provided justification showing that:
    a. SCE's WIM is better than the modeling framework SCE expressed concerns about in its Power Law White Paper.
    b. SCE's WIM can predict relative consequence (i.e., areas of low consequence versus areas of high consequence).
    c. SCE's WIM can predict relative consequence (i.e., areas of low consequence versus areas of high consequence).
    d. SCE's WIM can predict absolute risk (i.e., the magnitude of losses).

---

[470] PG&E Wildfire Consequence Model Version 4 (WFC v4) Documentation, p. 9 (https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/wildfire-consequence-model-documentation-v4.pdf, accessed Aug. 28, 2026); PG&E, Wildfire Distribution Risk Model Version 4 (WDRM v4) Documentation (rev. Mar. 11, 2025), §§ 5.1, 5.3, pp. 19–24 (https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/wildfire-distribution-risk-model-documentation-v4.pdf, accessed Sept. 24, 2026).

[471] Sempra 2025 RAMP Application: SDG&E 2025 Risk Assessment Mitigation Phase, Chapter SDG&E-Risk-4 "Wildfire and PSPS," p. 28 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/2025-sempra-ramp-application.pdf, accessed Aug. 26, 2026).

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[472]

Wildfire

SCE proposes 19 controls[473] and one mitigation[474] for wildfire risk.

SCE's one proposed mitigation (an activity beginning in 2029) is Sub-Transmission OH Conductor Replacement (M1).[475] SCE is proposing to install 957 splices over 2029-2032 to address "fundamental design limitations" on SCE's transmission system.[476] SCE indicates that its long-term strategy to address small wire sub-transmission circuit vulnerability is "Enhanced System Design (ESD)," providing "a durable, system-level risk reduction that addresses multiple wildfire-risk drivers in a single investment."[477]

PSPS

SCE proposes 10 controls[478] and no mitigations for PSPS risk.

Description of Wildfire Controls

Below are summary descriptions of the four wildfire controls with the largest proposed spend and two vegetation management controls whose O&M costs are relevant to the O&M savings SCE attributes to CC and TUG.

The four wildfire controls SPD describes below, accounting for about 72 percent of the total wildfire program spend,[479] are Wildfire Covered Conductor Program (WCCP) (C1), Targeted Undergrounding (TUG) (C2), Inspections for Vegetation Clearances from Distribution Lines (C8), and Distribution High Fire Risk Informed Inspections (HFRI) – Ground and Aerial (C9). The two vegetation management

---

[472] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[473] SCE 2026 RAMP Ch. 4, Table IV-9 "List of Wildfire Controls," p. 45.

[474] SCE 2026 RAMP Ch. 4, p. 73.

[475] SCE 2026 RAMP Ch. 4, p. 73.

[476] SCE 2026 RAMP Ch. 4, p. 73.

[477] SCE 2026 RAMP Ch. 4, p. 74.

[478] SCE 2026 RAMP Ch. 4, Table XI-46 "List of PSPS Controls," p. 104.

[479] SPD calculation based on SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80. According to this table, the total spend for the wildfire program is $5,118 million; the sum of the program total spends for controls C1, C2, C8, and C9 is $3,663 million, about 71.56 percent of the total.

controls that SPD describes below are Hazard Tree Management Program (HTMP) (C15) and Dead and Dying Tree Removal (C16).

Wildfire Covered Conductor Program (WCCP) (C1)
The covered conductor (CC) deployed under SCE's WCCP consists of an aluminum conductor protected by three layers of insulating material. SCE states that this design reduces (but does not eliminate) the likelihood of ignition by limiting electrical contact from common ignition mechanisms such as vegetation, conductor-to conductor contact, metallic balloons, etc. SCE further states that CC provides additional secondary public safety and reliability-related benefits, including reduced PSPS exposure. SCE proposes spending approximately $467.4 million on this program over the 2029-2032 RAMP period, covering approximately 455 circuit miles at a unit cost of $1.027 million per mile.[480]

SCE states that in selecting a circuit's best hardening option, it compares the BCRs of CC and TUG and determines if the selected scope overlaps with existing or planned deployment of rapid earth fault current limiters (REFCL) and then proceeds with the plan to install CC with REFCL if the BCR for that option in that location is greater than 1.0. [481]

SCE states that adding REFCL to CC reduces both wildfire and PSPS risk since it "can significantly reduce ignition risk and allow circuits to remain energized under more severe conditions by raising wind thresholds."[482] Specifically, SCE indicates that REFCL adds benefit to locations already hardened with CC by reducing "phase-to-ground ignition risk."[483] SCE states that it expects REFCL to add the incremental protection it intends when installed under these circumstances:[484]

- Execution is feasible within four years.
- Load transfers are manageable.
- The location is one of the highest wildfire risk substations and/or circuits that are majority CC.

SCE has two controls in its wildfire risk mitigation portfolio involving REFCL that SCE includes in its scope of work for 2026-2028 and 2029-2032: REFCL - Grounding Conversion (C4 or C5)[485] and REFCL - Ground Fault Neutralizer (C5 or C4).[486, 487] SCE notes numerous challenges with installing REFCL,

---

480 SCE 2026 RAMP Ch. 4, pp. 45-48.

481 SCE 2026 RAMP Ch. 4, Figure III-6 "BCR-Based Decision-Making Flow Chart," p. 42.

482 SCE 2026 RAMP Ch. 4, p. 15.

483 SCE 2026 RAMP Ch. 4, p. 42.

484 SCE 2026 RAMP Ch. 4, pp. 42-43.

485 SCE assigns control number "C4" to REFCL - Ground Fault Neutralizer per SCE 2026 RAMP Ch. 4, pp. 51-53.

486 SCE assigns control number "C5" to REFCL - Grounding Conversion per SCE 2026 RAMP Ch. 4, p. 54.

487 SCE assigns control number "C4" to REFCL - Grounding Conversion and "C5" to REFCL - Ground Fault Neutralizer per SCE 2026 RAMP Ch. 4, Table IV-9 "List of Wildfire Controls," p. 45.

including "significant distribution-level conversion work," adding that, although it has only installed six REFCL ground fault neutralizers (GFN) since 2021, "to SCE's knowledge no utility in North America has deployed REFCL GFN to a greater degree than SCE."[488] SCE proposes to install about 12 REFCL GFN by the end of 2028.[489] It refers to its progress as "deliberate" and "measured," noting that it is trying to "incorporate lessons learned into repeatable designs," which, together with other constraints, "inherently limits the pace of deployment and contributes to schedule uncertainty."[490]

Targeted Undergrounding (C2)

Targeted undergrounding (TUG) is a program that replaces existing overhead power lines with underground facilities. SCE states that TUG is a permanent grid-hardening solution that reduces wildfire ignition risk by minimizing the potential for objects to contact energized conductors by reducing ignition risks associated with equipment failures. SCE also states that TUG can virtually eliminate the need for PSPS on fully undergrounded circuits or isolatable segments, although customers may still be affected if upstream facilities remain overhead. SCE identifies locations where undergrounding may not be feasible due to factors such as rocky terrain, steep slopes, shallow bedrock, canyon crossings, or where significant rerouting is required because the existing route has no road to follow. SCE proposes spending approximately $889.7 million on this program over the 2029-2032 RAMP period, covering approximately 189 circuit miles at a unit cost of $4.707 million per mile.[491]

Inspections for Vegetation Clearances from Distribution Lines (C8)

Inspections for vegetation clearances from distribution lines aim to prevent vegetation from encroaching on distribution assets. These inspections are currently ground and/or remote sensing-based (aerial, LiDAR, and/or satellite). As part of the inspection scope, SCE states that it strives to obtain expanded clearances of 12 feet or greater for distribution lines in the HFRA. SCE inspects over 1.3 million trees adjacent to distribution facilities annually service-wide, including over 650,000 in the HFRA, and applies a 40 percent remediation rate (based on historical data) to determine the annual remediation scope. SCE proposes to spend approximately $1.119 billion on this program over the 2029-2032 RAMP period, covering approximately 1.04 million tree remediations (approximately 260,552 per year).[492]

In response to a data request, SCE provided the recorded and GRC-authorized cost history for inspections for vegetation clearances from transmission lines, reproduced in Table 1-6.[493] The spend for this control rose from approximately $169 million in 2019 to $320 million in 2020, and has since fluctuated between

[488] SCE 2026 RAMP Ch. 4, p. 52.

[489] SCE 2026 RAMP Ch. 4, p. 16.

[490] SCE 2026 RAMP Ch. 4, pp. 52-53.

[491] SCE 2026 RAMP Ch. 4, pp. 48-50.

[492] SCE 2026 RAMP Ch. 4, pp. 57-60.

[493] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21.

approximately $274 million and $372 million annually through 2025. GRC-authorized cost stepped up from approximately $125 million in 2023 to $412 million in 2024.[494]

[494] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 2.

Table 1-6. Vegetation Clearances from Distribution Lines (C8)[495]

Year	GRC-Authorized Cost[496] ($000)	GRC-Authorized Units[497]	Recorded Cost[498] ($000)	Recorded Volume[499] (Approx.)
2019	$65,333	N/A	$169,205	N/A[500]
2020	$66,579	N/A	$319,858	420,000
2021	$111,292	N/A	$299,047	600,000
2022	$111,918	N/A	$328,231	730,000
2023	$125,326	N/A	$274,450[501]	500,000
2024	$412,242	N/A	$303,256	620,000
2025	$423,149	790,000	$371,985	600,000
2026	$435,844	790,000	N/A[502]	N/A

Distribution High Fire Risk Informed Inspections (HFRI) – Ground and Aerial (C9)

Distribution HFRI is a targeted inspection program designed to identify asset conditions and external factors that could contribute to wildfire ignition risk on overhead distribution infrastructure. These inspections focus on equipment deterioration, structural deficiencies, and adjacent vegetation or other

[495] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

[496] "The GRC authorized amount for Vegetation Management is at the portfolio level. The costs reflected in this table for GRC Activity Distribution Routine Vegetation Management include High-Fire and Non-High Fire Distribution Line Clearing activities and inspections and other sub-activities, including LiDAR, weed abatement, emergent work, seasonal patrols, traffic control, and customer support" per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

[497] "For 2019-2024, the GRC authorized units is not applicable, because the Commission authorized dollars and not specific units for this activity. For 2025-2026, SCE is providing the total Transmission and Distribution mitigation volume identified in SCE's 2025 GRC forecast" per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

[498] "The recorded cost includes Distribution line clearing and inspection costs in high fire and non-high fire areas and other sub-activities, including LiDAR, weed abatement, emergent work, seasonal patrols, traffic control, and customer support" per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

[499] "The recorded volume includes all Distribution line clearing mitigations in high fire and non-high fire areas" per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

foreign objects in proximity to distribution assets. The program supplements General Order (GO) 165, which requires detailed inspections of overhead distribution assets at least every five years, by providing more frequent risk-informed inspections across SCE's HFRA. HFRI builds on SCE's prior Enhanced Overhead Inspections (EOI) program and uses a combination of ground-based and aerial methods, including drones and helicopters, to provide complementary perspectives on asset condition. SCE proposes to spend approximately $1.186 billion on this program over the 2029-2032 RAMP period, covering approximately 150,400 asset remediations (approximately 37,600 per year). [503]

Hazard Tree Management Program (HTMP) (C15)

The HTMP identifies, documents, and mitigates trees located within striking distance (fall-in risk) of electrical facilities. The program's approach is based on the tree's observed structural condition as well as site considerations. The program addresses the potential risk to SCE's electric facilities from structurally unsound trees that can fail in whole or in part, and from palm trees that can dislodge palm fronds during high winds. Circuits in the highest risk category (A) follow an annual HTMP inspection cycle, while circuits in categories B, C, and D follow a three-year inspection cycle. SCE proposes to spend approximately $128.6 million on this program over the 2029-2032 RAMP period, covering approximately 24,161 tree remediations (approximately 6,040 per year).[504]

Dead and Dying Tree Removal (C16)

SCE states that it continues to proactively remove dead, dying, and diseased trees that could fall on or contact SCE's electrical facilities. SCE proposes to spend approximately $158.9 million on this program over the 2029-2032 RAMP period, covering approximately 33,026 tree remediations (approximately 8,257 per year).[505]

The spends and BCRs for the six wildfire controls summarized above are described in Table 1-7.

---

[500] "For Inspections for Vegetation Clearances from Distribution Lines (C8), although this activity was performed prior to 2019, the volume for Distribution only was not separately tracked until 2020" per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

[501] "Starting in 2023, HTMP and Dead and Dying Tree Removal inspection costs were consolidated and recorded under Routine inspections" per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

[502] "2026 recorded values are not included, as complete and final recorded cost and volume data for the year are not yet available" per SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 21(a).

[503] SCE 2026 RAMP Ch. 4, pp. 57-59.

[504] SCE 2026 RAMP Ch. 4, pp. 65-66.

[505] SCE 2026 RAMP Ch. 4, pp. 66-68.

Table 1-7. Proposed Plan Programmatic Wildfire Estimated Spend and Benefit-Cost Ratios for Selected Wildfire Controls (2029-2032)($000s)[506]

RAMP ID	Control / Mitigation Name	O&M	Capital	Total	BCR (WACC)	BCR (Societal)	BCR (Hybrid)
C1	Wildfire Covered Conductor Program		$467,351	$467,351	9.18	13.24	10.01
C2	Targeted Undergrounding		$889,737	$889,737	9.28	59.55	9.52
C8	Inspections for Vegetation Clearances from Distribution Lines	$1,119,109		$1,119,109	0.51	0.51	0.51
C9	Distribution High Fire Risk Informed Inspections	$640,386	$546,134	$1,186,519	24.10	47.53	24.55
C15	Hazard Tree Management Program	$128,574		$128,574	1.23	4.16	1.27
C16	Dead and Dying Tree Removal	$158,933		$158,933	0.53	1.81	0.55
Subtotal-Selected Controls		$2,047,002	**$1,903,222**	$3,950,224			
	Total – Proposed Plan (19 controls and 1 mitigation)	**$2,424,564**	**$2,693,730**	**$5,118,294**	**11.27**	**22.77**	**11.59**

The six wildfire controls listed above account for approximately $3.95 billion, approximately 77 percent, of SCE's $5.12 billion total 2029-2032 proposed plan wildfire spend. Capital-intensive programs (C1, C2, and the capital portion of C9) total approximately $1.90 billion, while O&M-intensive programs (C8, the O&M portion of C9, C15, and C16) total approximately $2.05 billion. The programs with the highest reported BCRs, C9 (24.10 WACC), C2 (9.28), and C1 (9.18), predominantly have capital costs, while the two programs with BCRs below 1.0 (C8 [0.51] and C16 [0.53]) entail only O&M costs and together account for approximately $1.28 billion, or approximately 25 percent of SCE's total proposed 2029-2032 wildfire spend.

[506] SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

Observations and Findings

SPD finds the following about SCE's vegetation management controls:

20. SCE's inspection and vegetation management controls (C8, C9, C15, and C16) collectively represent approximately $2.59 billion in proposed 2029-2032 spend.[507] SCE reports BCRs for two of these controls that fall far below the 1.0 BCR threshold that SCE applies to grid-hardening mitigations: Inspections for Vegetation Clearances from Distribution Lines (C8) has a BCR of 0.51 and Dead and Dying Tree Removal (C16) has a BCR of 0.53. The Hazard Tree Management Program (C15), with a BCR of 1.23, barely exceeds the 1.0 BCR threshold. Together these three programs account for approximately $1.41 billion in proposed spend, with approximately $1.28 billion in proposed spend for the two programs with BCRs that do not meet the 1.0 BCR threshold. Although low-BCR controls might be necessary to meet statutory requirements and other compliance obligations, SPD notes that portions of these programs exceed the minimum activity mandated by statute, regulation, or Commission order (e.g., General Order 95 Rule 35,[508] Public Resources Code 4292 and 4293[509]), and SCE has not separately justified the discretionary scope above that compliance floor on cost-effectiveness grounds. Because SCE applies a 1.0 BCR threshold to its grid-hardening mitigations, and because a BCR below 1.0 indicates that a program's benefits are less than its costs, the below-threshold discretionary scope is not consistent with the cost-efficiency principle SCE applies elsewhere in its proposed plan. To the extent SCE could exclude or evaluate separately this discretionary, above-compliance scope, resources SCE currently allocates to low-BCR inspection and vegetation management activity could be redirected toward higher-BCR mitigations.

SPD discusses issues with SCE's presentation of costs and benefits for wildfire controls below in "BCR Calculations."

Alternatives Analysis

SCE presents two alternatives to each of its proposed plans for mitigating wildfire and PSPS risk.

---

[507] SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

[508] CPUC General Order 95, Section III "Requirements for All Lines," Part 35 "Vegetation Management" (https://ia.cpuc.ca.gov/gos/GO95/go_95_rule_35.html, accessed Sept. 4, 2026).

[509] California Public Resources Code 4291-4299 (https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PRC&division=4.&title&part=2.&chapter=3.&article, accessed Sept. 4, 2026). Public Resources Code 4092 and 4093 describe vegetation management requirements for electrical transmission or distribution lines.

Wildfire

Alternative Plan 1 increases deployment of CC, expanding wildfire mitigation hardening to all remaining overhead bare conductor within the HFRA.[510] While the proposed plan targets locations with the highest BCRs (where the BCR is greater than 1.0) for overhead hardening, this alternative broadens the overhead hardening footprint across the full remaining HFRA at approximately the same total cost. Alternative Plan 1 reduces TUG to approximately 120 miles (from 189 in the proposed plan, a 37 percent reduction per SPD calculation), while expanding CC to approximately 751 miles (from 455 in the proposed plan, a 65 percent increase per SPD calculation).[511, 512] Under this plan, total hardened mileage rises to approximately 871 miles (adding CC and TUG miles), a 35 percent increase from the proposed plan's 644 miles per SPD calculation. SCE notes that CC may be paired with REFCL where technically feasible.[513] SCE estimates approximately the same total cost for Alternative Plan 1 and the proposed plan.[514]

The proposed plan has advantages over Alternative Plan 1 in terms of risk reduction and BCRs. SCE's estimate of risk reduced over the RAMP cycle (2029-2032) by Alternative Plan 1 is about $208 million (3.0 percent), less than the proposed plan's $262 million (3.8 percent).[515] SCE estimates that the wildfire risk LoRE will decrease by 9 under Alternative Plan 1 over the RAMP cycle, while the proposed plan decreases LoRE by 11.[516] SCE estimates a 10.64 BCR (WACC method) for Alternative Plan 1, which is lower than the proposed plan's BCR (WACC method) of 11.27.[517] Additionally, SCE states that Alternative Plan 1 leaves more risk than the proposed plan in some of the highest-risk, most climate-sensitive areas by reducing

---

[510] SCE 2026 RAMP Ch. 4, pp. 82-86.

[511] SCE 2026 RAMP Ch. 4, p. 83.

[512] SCE 2026 RAMP Ch. 4, Table VII-33 "Proposed Plan Programmatic Wildfire Estimated Unit Deployments," p. 77.

[513] SCE 2026 RAMP Ch. 4, p. 83.

[514] The proposed and Alternative 1 plans cost either the same or approximately the same: SCE gives different numbers in different places for these plans' costs. The costs are the same, namely $2,483,704 thousand O&M, $2,718,785 thousand capital, and $5,202,489 thousand total per SCE 2026 RAMP Ch. 4, Table VIII-36 "Summary of Estimated Spend ($000s) and Plan BCRs for Wildfire Risk," p. 82. However, in another table, SCE presents the proposed plan as costing $2,424,564 thousand O&M, $2,693,730 thousand capital, and $5,118,294 thousand total per SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80, while SCE presents Alternative Plan 1 as costing $2,424,564 thousand O&M (the same as the proposed plan in Table VII-34), $2,694,691 thousand capital ($961 more than the proposed plan), and $5,119,254 thousand total ($960 thousand more than the proposed plan) per Table VIII-38 "Alternative Plan #1 Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 85. SPD calculates the total of the O&M and capital costs from Table VIII-38 at $5,119,255 thousand (1 thousand more than SCE's calculation).

[515] SPD calculation per pre- and post-mitigation risk values in SCE 2026 RAMP Ch. 4, Table VIII-35 "Summary of Pre and Post LoRE Risk Scores for Wildfire Risk for Proposed and Alternative Plans," p. 82.

[516] SPD calculation per SCE 2026 RAMP Ch. 4, Table VIII-35 "Summary of Pre and Post LoRE Risk Scores for Wildfire Risk for Proposed and Alternative Plans," p. 82.

[517] SCE 2026 RAMP Ch. 4, Table VIII-36 "Summary of Estimated Spend ($000s) and Plan BCRs for Wildfire Risk," p. 82.

TUG, which is more effective at risk reduction than CC, in these areas.[518] SCE notes that Alternative Plan 1 is more feasible in the sense that CC is a "lower-cost, faster-paced mitigation approach," but it does not eliminate overhead risk, so it does not reduce wildfire risk as much as the proposed plan.[519]

Alternative Plan 2 gives "the deepest reduction in wildfire risk of the three portfolios,"[520] leaving the CC miles unchanged (455 miles) but adding 37 miles of TUG on top of the 189 miles in the proposed plan,[521, 522] including in areas previously hardened with CC "because they may also face disproportionate risk even after CC installation, particularly under changing climate conditions."[523] SCE estimates that Alternative Plan 2 will be more expensive than both the proposed plan and Alternative Plan 1.[524]

Alternative Plan 2 has an advantage over the proposed plan in terms of risk reduction measured in monetized terms but offers equal LoRE reduction and an equivalent BCR. SCE's estimate of risk reduced over the RAMP cycle (2029-2032) by Alternative Plan 2 is about $367 million (5.3 percent), more than the proposed plan's $262 million (3.8 percent).[525] SCE estimates that the wildfire risk LoRE change under Alternative Plan 2 over the RAMP cycle will be the same as the proposed plan, a decrease of 11.[526] SCE estimates a 11.33 BCR (WACC method) for Alternative Plan 2, which is almost the same as the proposed plan's BCR (WACC method) of 11.27—both round to a BCR of 11.3.[527] SCE prefers the proposed plan over this plan due to challenges such as "higher capital requirements, increased construction demands, as

---

[518] SCE 2026 RAMP Ch. 4, p. 84.

[519] SCE 2026 RAMP Ch. 4, p. 85.

[520] SCE 2026 RAMP Ch. 4, p. 87.

[521] SCE 2026 RAMP Ch. 4, p. 86-87.

[522] SCE 2026 RAMP Ch. 4, Table VII-33 "Proposed Plan Programmatic Wildfire Estimated Unit Deployments," p. 77.

[523] SCE 2026 RAMP Ch. 4, p. 86.

[524] Alternative Plan 2 is more expensive than the other two plans, but SCE presents different numbers in different places for this plan's costs, as with the proposed plan and Alternative Plan 1. The total cost for Alternative Plan 2 is $5,407,580 thousand per SCE 2026 RAMP Ch. 4, Table VIII-36 "Summary of Estimated Spend ($000s) and Plan BCRs for Wildfire Risk," p. 82. That is more than the proposed plan's total cost in the same table, $5,202,489 thousand, and more than the proposed plan's total cost in "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios" on p. 80, $5,118,294. Elsewhere, SCE presents the total cost for Alternative Plan 2 as $5,289,300 thousand in a mislabeled table (under heading "B. Alternative Plan #2 – Wildfire," Table VIII-41 "Alternative Plan **#1** Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios" (bold added), p. 90, the same title as Table VIII-38 "Alternative Plan #1 Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," on p. 85) This is still more than both of SCE's two proposed plan total costs.

[525] SPD calculation per pre- and post-mitigation risk values in SCE 2026 RAMP Ch. 4, Table VIII-35 "Summary of Pre and Post LoRE Risk Scores for Wildfire Risk for Proposed and Alternative Plans," p. 82.

[526] SPD calculation per SCE 2026 RAMP Ch. 4, Table VIII-35 "Summary of Pre and Post LoRE Risk Scores for Wildfire Risk for Proposed and Alternative Plans," p. 82.

[527] SCE 2026 RAMP Ch. 4, Table VIII-36 "Summary of Estimated Spend ($000s) and Plan BCRs for Wildfire Risk," p. 82.

well as feasibility challenges associated with removing installed CC and replacing it with underground infrastructure" in addition to the impracticality of undergrounding lines in some locations.[528]

PSPS

Alternative Plan 1 expands grid-hardening activities consistent with SCE's Wildfire Alternative Plan 1.[529] SCE under this plan would target circuits most frequently impacted by PSPS for hardening, "with the objective of increasing PSPS windspeed thresholds and reducing the frequency and/or duration of de-energization events."[530] SCE considers this alternative relatively low in cost-effectiveness because by 2029 SCE should have already hardened the circuits most frequently impacted by PSPS, so remaining PSPS risk may be relatively costly to address through hardening "while yielding limited incremental reductions in PSPS risk."[531]

Alternative Plan 2 expands customer support programs.[532] However, SCE cites the possibility that customer support programs may be reaching saturation, "as evidenced by declining enrollment rates for existing programs despite increased outreach" and "reduced customer participation during PSPS events," so the effectiveness of these programs may be declining over time, making the plan less attractive than the proposed plan.[533]

The BCRs for all three PSPS risk mitigation plans are low. [534] In fact, the proposed plan's BCR is the lowest of the three plans (using the WACC discounting method, 0.22, compared to 0.31 for Alternative Plan 1 and 0.27 for Alternative Plan 2).[535] For PSPS risk, the plan with the highest BCR may not meet SCE's regulatory and other obligations to reduce PSPS risk. For more discussion of the low BCRs SCE estimates for its PSPS plans, see "BCR Calculations" below.

Observations and Findings

SPD finds the following about SCE's alternative plans for wildfire risk reduction:

---

[528] SCE 2026 RAMP Ch. 4, p. 87.

[529] SCE 2026 RAMP Ch. 4, pp. 121-123.

[530] SCE 2026 RAMP Ch. 4, p. 121.

[531] SCE 2026 RAMP Ch. 4, p. 122.

[532] SCE 2026 RAMP Ch. 4, pp. 123-125.

[533] SCE 2026 RAMP Ch. 4, p. 123.

[534] SCE 2026 RAMP Ch. 4, Table XIII-59 "Summary of Estimated Spend and Plan BCRs for PSPS Risk," p. 119.

[535] SCE 2026 RAMP Ch. 4, Table XIII-59 "Summary of Estimated Spend and Plan BCRs for PSPS Risk," p. 119.

21. Wildfire Alternative Plan 2 differs from the proposed plan solely by the addition of 37 miles of TUG. These additional miles include areas with "disproportionate risk" even after CC installation, in other words, in some cases it would be replacing CC with TUG.[536] SCE estimates that this alternative would give the greatest monetized risk reduction of the three plans.[537] Using SCE's estimates for risk reduction for these additional 37 miles of TUG, SPD calculates that SCE credits these additional 37 miles of TUG with a monetized risk reduction of $2,827.9 thousand per mile per year, or 2.04 times the per mile per year figure SPD calculates for the risk reduction under the proposed plan ($1,389 thousand per mile per year), crediting all risk reduction to that plan's 189 miles of TUG (note that SPD's assumption here is not based on evidence, it is a hypothetical experiment). If SPD attributes the proposed plan's monetized risk reduction proportionally across all hardened miles (644, adding 189 TUG and 455 CC miles), the risk reduction is $407.6 thousand per mile per year. The per mile per year risk reduction figure SPD calculates for the 37 miles of TUG under Alternative Plan 2 is about 7 times this number. Under both sets of assumptions, SCE's estimated risk reduction from TUG under the proposed plan is far less than the risk reduction from TUG under Alternative Plan 2, where TUG would in some places be replacing CC. This result is hard to reconcile with SCE's own mitigation effectiveness assumptions. Because CC provides risk reduction over bare wire, replacing CC with TUG should yield less risk reduction than replacing bare wire with TUG, but the Alternative Plan 2 estimates assume it would yield more risk reduction than replacing bare wire with TUG.[538]

[536] SCE 2026 RAMP Ch. 4, p. 86.

[537] SPD calculation per pre- and post-mitigation risk values in SCE 2026 RAMP Ch. 4, Table VIII-35 "Summary of Pre and Post LoRE Risk Scores for Wildfire Risk for Proposed and Alternative Plans," p. 82.

[538] SCE 2026 RAMP Ch. 4 work paper "Wildfire Mitigation Effectiveness," tab "Wildfire Summary," indicates that for "Subdriver/ Consequence Type" "Veg. contact – Distribution" the "Mitigation Effectiveness" for "Covered Conductor" is "71%" and for "Targeted Undergrounding" it is "100%."

BCR Calculations

Wildfire

SCE calculates BCR values for its 19 controls and one mitigation for wildfire risk.[539]

The BCR for SCE's proposed plan for wildfire risk is, per discounting method, 11.27 (WACC basis), 22.77 (societal basis), or 11.59 (hybrid basis).[540]

In its 2026 RAMP, SCE states that SCE is "*not* selecting grid hardening mitigations that have a benefit-cost ratio (BCR) of less than 1.0.[541] SCE further states that it uses circuit-level BCRs to determine scope for TUG, comparing the circuit-level BCR for TUG to the circuit-level BCRs of CC and CC with REFCL[542, 543] For each circuit, SCE selects the option with the highest circuit-level BCR that is 1.0 or higher (see Figure 1-3),[544] provided the option is technically feasible.[545] SCE notes that it is only proposing TUG "in the highest-risk remaining unhardened portions of HFRA where installation is also technically feasible."[546] In high-risk unhardened locations in the HFRA where TUG is not cost-effective or is infeasible, SCE proposes CC or CC with REFCL.[547]

[539] SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

[540] SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

[541] SCE 2026 RAMP Ch. 4, p. 1.

[542] SCE 2026 RAMP Ch. 4, p. 47.

[543] For more information, see SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding."

[544] SCE 2026 RAMP Ch. 4, Figure III-6 "BCR-Based Decision-Making Flow Chart," p. 42.

[545] SCE 2026 RAMP Ch. 4, p. 42.

[546] SCE 2026 RAMP Ch. 4, p. 41.

[547] SCE 2026 RAMP Ch. 4, p. 42.

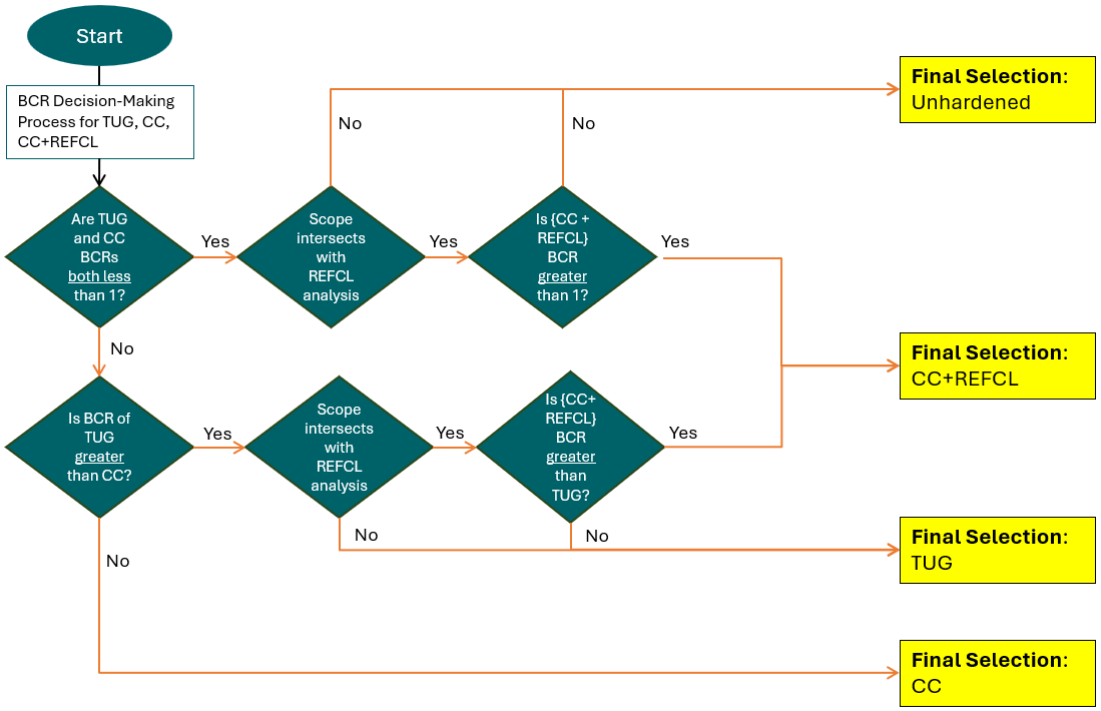


Figure 1-3. SCE's BCR-Based Decision-Making Flow Chart[548]

In reference to SCE's methodology for calculating BCRs,[549] SCE states that it "evaluated the mitigation alternatives, including TUG, CC, and CC paired with REFCL, using a BCR framework consistent with Commission Resolution SPD-37, Senate Bill 884, and the Joint IOU methodology in that process," referring to the methodology proposed by in the "Joint Application Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions," which the large IOUs jointly submitted on February 9, 2026.[550, 551]

SCE calculates a BCR value for both CC and TUG using this formula:

[548] SCE 2026 RAMP Ch. 4, Figure I-1 "BCR-Based Decision-Making Flow Chart," p. 5.

[549] SCE 2026 RAMP Ch. 2, pp. 25-29.

[550] SCE 2026 RAMP Ch. 4, p. 20.

[551] 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 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M598/K101/598101196.PDF, accessed Sept. 1, 2026).

BCR = Modeled Benefit from CC or TUG /
[Capital Cost for CC or TUG + (O&M Cost - O&M Savings)][552]

PSPS

SCE calculates BCR values for 10 controls for PSPS risk.[553]

The BCR for SCE's proposed plan for PSPS risk is low regardless of the discounting method: 0.22 (WACC basis) or 0.23 (societal and hybrid bases). SPD discusses the low BCRs for PSPS controls below.

Observations and Findings

SPD observes that SCE's decision-making framework appears to select among CC, TUG, and CC with REFCL based primarily on comparative BCR values, not selecting grid hardening mitigations with a BCR below 1.0. In other words, when multiple mitigation alternatives meet the minimum BCR threshold, SCE appears to prioritize the mitigation with the higher BCR value.

Background on BCR Methods

Regarding BCR calculation methods, the Commission has not established a standard method for calculating a BCR outside of the general guidance in the RDF decisions. As noted earlier, the RDF Phase 2 Decision requires the use of cost-benefit ratios (CBRs) in RAMP and GRC filings, defined as a value "calculated by dividing the dollar value of [m]itigation [b]enefit by the [m]itigation cost estimate"[554] and, because the ratio is expressed as benefit/cost, the RDF Phase 4 Decision updated the term from cost-benefit ratios to benefit-cost ratios (BCRs).[555] The most current CPUC guidance on calculating BCRs in the RDF Phase 4 Decision does not, for example, discuss how to account for O&M savings or expenses in a BCR calculation.[556]

As referenced above, SCE states that it "aligned its BCR calculation with the approach described in the Joint IOU application filed in pursuant to CPUC Resolution SPD-37 and Senate Bill 884,"[557] pointing to Resolution SPD-37 (from October 30, 2025), pertaining to the Senate Bill (SB) 884 Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations. Resolution SPD-37 does

[552] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-1.

[553] SCE 2026 RAMP Ch. 4, Table XIII-61 "Proposed Plan Programmatic PSPS Estimated Spend ($000s) and Benefit-Cost Ratios," p. 120.

[554] D.22-12-027, Appendix A, Definitions, p. A-3; Rows 1-7, pp. A-9-A-10.

[555] D.25-08-032, Appendix A, Definitions, p. A-3.

[556] D.25-08-032, Appendix A, Rows 1-7, pp. A-9-A-10.

[557] SCE 2026 RAMP Ch. 4, p. 28.

not establish a standard method for calculating a BCR.[558] Meanwhile, on April 10, 2026, the Commission published a scoping ruling and memo in response to the IOUs' joint application regarding BCR methods under the SB 884 Program, including a white paper authored by SPD staff proposing an approach to BCR calculations as an attachment.[559] This staff white paper proposes a BCR calculation incorporating only incremental benefits or costs (those that occur on top of the baseline benefits or costs)[560] and treats O&M costs and O&M benefits (i.e., O&M savings) separately, incorporating incremental O&M costs in the denominator and incremental O&M savings in the numerator of the BCR formula.[561]

Below SPD discusses issues it found in SCE's method of calculating BCRs for wildfire mitigations, including issues SPD found in SCE's Chapter 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," and in SCE's calculation of inputs to its BCRs (e.g., estimated mitigation benefits and costs discrepancies), and in SCE's calculation of its BCR for REFCL. SPD also comments on SCE's low BCRs for its customer-facing PSPS programs below.

Discrete Arithmetic Error in the TUG Net O&M Formula

The first of three issues SPD identifies in SCE's Chapter 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding" is a discrete arithmetic error in its formula for calculating net O&M for TUG.

In this work paper, SCE states, "O&M cost of bare conductor is approximately $62K per mile per year for existing overhead (OH) infrastructure," and "O&M cost of TUG is approximately $7K per mile per year for existing OH infrastructure," noting that for both these costs reflect "current inspection costs, maintenance and failure-driven cost experienced."[562] SCE presents the formula for calculating net O&M as O&M costs minus O&M savings[563] and net O&M for TUG as:[564]

---

[558] CPUC Safety Policy Division, Resolution SPD-37 Update and Revision of Senate Bill 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations (October 30, 2025) (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M583/K834/583834088.pdf, accessed Sept. 1, 2026).

[559] Assigned Commissioner's Scoping Memo and Ruling and Attachments for Application (A.) 26-02-005 (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=604545275, accessed Sept. 1, 2026). See also the docket for A.26-02-005 (https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:A2602005, accessed Sept. 1, 2026).

[560] Staff White Paper on Benefit-Cost Ratio Methodology (April 10, 2026) (SPD Staff BCR White Paper), p. 16 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K545/604545276.PDF, accessed Sept. 1, 2026). SPD references this white paper for illustrative purposes only. It is not an authoritative source for BCR requirements for utility RAMP applications.

[561] SPD Staff BCR White Paper, p. 2.

[562] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-2.

[563] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-1.

[564] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-3.

O&M cost of TUG - (O&M cost of bare conductor - O&M cost of UG[565])
= $7K - ($62K - $7K)
= $7K - $55K
= - $48K/mile O&M to maintain TUG/year vs. OH Construction

Expanding algebraically, this calculation has the structure N - (B - N) = 2N - B, where N is the TUG operational cost (i.e., TUG O&M costs) and B is the bare conductor O&M baseline cost ($62K/mile/year). This structure treats the entire bare-conductor O&M baseline as being eliminated by TUG installation (i.e., B is treated as fully equivalent to O&M savings). As a result, the TUG O&M cost ($7K) appears twice in the calculation: once as the operational cost being added and once embedded within the O&M savings term as a subtraction from the baseline. To address this apparent double counting, SPD sent SCE the following data request question:[566]

> Assuming no-build baseline O&M costs (B) (which might be the same as "O&M cost of bare conductor") and O&M costs (N) of the new mitigation (i.e., TUG or CC), does SCE's TUG total net O&M formula (2N − B = $14K − $62K = −$48K) effectively double-count the TUG O&M cost?

SCE responded, "No. SCE does not consider the TUG formulation to result in double counting,"[567] adding that while the formula can be presented algebraically as:

Total Net O&M = N - (B - N)
=2N - B

SCE asserts this formula does not represent double counting because "N represents the ongoing cost of the underground asset," "(B − N) represents the avoided overhead O&M," and "[b]oth elements are required to fully reflect the net cost impact of transitioning from overhead to underground."[568]

SCE's response does not address the algebraic consequence that N is both subtracted from the baseline and separately added as the new operating cost. Under a treatment in which O&M savings reflects only the avoided baseline activity, SPD believes the correct calculation should be:

Net O&M(TUG)
= N - B
= $7K - $62K
= -$55K/mile/year (assuming installing TUG eliminates the existing bare-conductor O&M cost of $62K/mile/year)

---

[565] SCE doesn't define the term "UG." SPD here glosses this term with "TUG."

[566] Data Request SPD-SCE-2026 RAMP-006, Question 1(d).

[567] SCE response to Data Request SPD-SCE-2026 RAMP-006, Question 1(d).

[568] SCE response to Data Request SPD-SCE-2026 RAMP-006, Question 1(d).

The $7K difference between SCE's reported -$48K and this -$55K corresponds exactly to N being counted a second time. Because SCE includes net O&M in the BCR denominator, SCE correcting this error would increase its BCR for TUG, possibly resulting in SCE prioritizing TUG over other mitigation measures where otherwise TUG may not be competitive. For that reason, SPD identifies this as a discrete arithmetic error rather than a source of comparative distortion of BCRs.

SPD finds the following about SCE's discrete arithmetic error in the TUG net O&M formula:

22. SCE's net O&M formula for TUG counts the new TUG O&M cost (N) twice within the same formula. SPD finds that this is a discrete, demonstrable error in SCE's arithmetic. SCE confirmed the 2N - B structure of its formula and defended it, but its defense does not address the fact that N is both subtracted from the baseline (B) and separately added as the new operating cost.[569]

SCE's Use of Inconsistent Baselines to Calculate O&M Cost for CC and TUG

The second of three issues SPD identifies in SCE's Chapter 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding" is an inconsistency between the O&M cost inputs SCE substitutes for CC and for TUG.

As noted above, in this work paper SCE calculates net O&M as O&M costs minus O&M savings.[570] By that formula, SCE estimates net O&M cost for CC at $47K per mile per year.[571] This is based on SCE's $62K per mile per year estimate for the O&M cost of bare conductor, which is uses as a proxy for O&M cost for CC, and its estimate of O&M savings from the installation of CC at $15K per mile per year "based on observed maintenance expenditures and failure-related costs associated with existing overhead infrastructure."[572]

SCE presents the formula for calculating net O&M for CC as:[573]

O&M cost of bare conductor – O&M savings
= $62K - $15K
= $47K/mile/year O&M to maintain recently replaced OH construction

[569] SCE response to Data Request SPD-SCE-2026 RAMP-006, Question 1(d).

[570] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-1.

[571] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," pp. WP-1-WP-2.

[572] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-2.

[573] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-3.

According to this work paper, when calculating BCRs for TUG and CC, SCE applies the same denominator structure: O&M cost minus O&M savings.[574] However, the inputs SCE applies to this formula are asymmetrical for these mitigations. For CC, O&M cost is the $62K per mile per year cost for existing bare wire overhead infrastructure while TUG O&M cost is the $7K per mile per year underground operating cost, an incremental expense.

The RDF Phase 4 Decision directs utilities, when calculating BCRs for capital programs, to include "incremental expenses made necessary by the capital investment" in the BCR denominator.[575] This directive is inconsistent with SCE treating the $62K per mile per year cost for existing bare wire overhead infrastructure as the starting O&M cost for CC. SCE should only include incremental O&M cost or savings introduced or eliminated by a mitigation in its BCR calculation. As noted above, SCE describes the $62K cost as reflecting "current inspection costs, maintenance and failure-driven cost experienced" for bare wire overhead infrastructure while simultaneously using that cost as a proxy for O&M cost for CC.[576]

In response to a data request looking at the O&M cost estimates for CC, SCE stated, "N (CC) = O&M cost post-CC (implicit in framework) = $62k" … "Where N_CC represents post-mitigation O&M for covered conductor (consistent with workpaper assumptions)" and "the explicit derivation of N_CC is not separately presented."[577] Elsewhere in the response SCE stated that the "Mitigation O&M (N)" for "CC" is "$62K (Not explicitly disaggregated in workpaper)."[578] In response to a follow-up data request, SCE explained, "Because covered conductor assets are maintained as part of the broader overhead distribution system and O&M activities are generally tracked at the system level rather than by conductor type, a covered conductor-specific historical O&M cost is not available."[579] SCE added that the $62K per mile per year estimate "is based on historical HFRA overhead system O&M expenditures."[580] SCE defends including the full $62K, rather than incremental O&M for CC, on the grounds that it "represents the best available estimate of ongoing overhead system O&M costs within HFRA."[581] SPD believes the incremental ongoing O&M for CC belongs in the cost term for the BCR for CC, not the estimated O&M for existing bare wire overhead infrastructure, effectively comparing CC to a no-infrastructure baseline instead of CC to bare wire.

---

[574] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," pp. WP-1-WP-1.

[575] D.25-08-032, Appendix A, Row 25, p. A-19.

[576] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-2.

[577] SCE response to Data Request SPD-SCE-2026 RAMP-006, Question 1(g).

[578] SCE response to Data Request SPD-SCE-2026 RAMP-006, Question 1(h), Table A "Breakdown of O&M Calculations."

[579] SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 28(a).

[580] SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 28(a)(i).

[581] SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 28(c).

In a separate data request regarding the baseline O&M activity level SCE is assuming will be avoided by CC and TUG, SCE responded that "[f]or Covered Conductor (C1), SCE does not assume avoided vegetation management O&M activity, as inspection and remediation requirements remain unchanged post-installation," while "[f]or Targeted Undergrounding (C2), vegetation management activities … are fully avoided."[582] SCE thus affirms that the same baseline activity continues under CC but is eliminated under TUG, yet SCE incorporates the full cost of existing bare wire overhead maintenance in the BCR denominator for CC as though newly incurred by the installation of CC.

SPD asked SCE in a data request, "Is the covered conductor's own post-installation O&M cost (N_CC) $62K per mile per year?"[583] SCE responded, "The use of the assumption of $62k per mile per year should not be interpreted to mean that covered conductor and bare conductor will incur identical O&M costs over their service lives," meanwhile asserting that the assumption that O&M cost for CC will be $62K per mile per year "is not inconsistent with SCE's statement that newly-installed covered conductor is expected to reduce remediation activity relative to existing bare conductor over its lifetime."[584]

SPD further notes that SCE indicates that installation of CC leads to $15K in O&M savings. SCE indicates this amount is deduced from "observed maintenance expenditures and failure-related costs associated with existing overhead infrastructure … adjusted using a conservatively discounted savings profile over the first 25 years to account for the lower expected likelihood of corrective maintenance and failure events during the early life of newly installed or substantially replaced assets and components. … This approach assumes lower problem/fix rate relative to the system average, reflecting new covered conductor installations used to replace degraded components and update assets with current design standards."[585] SPD notes that SCE has not provided sufficient support for either its O&M cost ($62K) or savings ($15K) estimates for CC.

Taken together, SCE applies inconsistent baselines to calculate O&M costs for CC and TUG. For CC, it uses a no-infrastructure baseline, which assumes no pre-existing O&M activity even though such activity exists and is funded. For TUG, it uses a no-build baseline, which accounts only for the incremental O&M costs of TUG relative to existing OH construction. SPD's white paper attached to the Resolution SPD-37 Scoping Ruling and Memo discusses how mixed baselines can distort BCRs.[586]

The practical consequence is that SCE is including pre-existing, already-authorized bare-conductor O&M activity in the BCR denominator for CC—as CC's own O&M cost—while SCE only includes the

[582] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 23(a).

[583] Data Request SPD-SCE-2026 RAMP-010, Question 28(b).

[584] SCE response to Data Request SPD-SCE-2026 RAMP-010, Question 28(b).

[585] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," pp. WP-2-WP-3.

[586] SPD Staff BCR White Paper, pp. 14-18.

incremental cost of operating the underground asset in the BCR denominator for TUG, even though SCE compares both to the same existing bare wire overhead infrastructure.

SPD finds the following about SCE's use of inconsistent baselines to calculate O&M cost for CC and TUG:

23. SCE uses an estimated $62K per mile per year existing bare wire overhead infrastructure O&M cost as a proxy for the O&M cost for CC. SCE bases this $62K estimate on historical HFRA overhead system O&M expenditures rather than an estimate of the incremental O&M cost for CC. In data request responses, SCE acknowledged that it lacks a specific CC O&M cost estimate.[587] SCE applies its $62K O&M cost differently in its BCR calculation for CC and for TUG, including it as a proxy for O&M cost for CC and as an avoided O&M cost, or O&M savings, for TUG. SCE also does not break down the $62K estimate by cost component, such as vegetation management, stating that it does not disaggregate avoided O&M costs between compliance and discretionary components.

24. SCE's use of its $62K per mile per year estimate of baseline bare wire O&M cost as a proxy for the O&M cost for CC is inconsistent with the RDF Phase 4 Decision, which directs utilities, when calculating BCRs for capital programs, to include incremental expenses in the BCR denominator.[588] The BCR calculation of O&M costs or savings should only include incremental O&M activity introduced or eliminated by a new mitigation. SCE describes the $62K estimate in its work paper, "BCR Methodology for Covered Conductor and Targeted Undergrounding," as the baseline O&M cost of existing bare overhead conductor. It is not an O&M cost introduced by installing CC.[589] SCE should not include that baseline in the O&M cost for CC, only the incremental cost introduced by installing CC. SCE should only incorporate the existing baseline O&M cost as O&M savings, as part of avoided or reduced activity. SCE effectively calculates the O&M cost for CC as though the alternative is a no-infrastructure baseline (assuming no existing O&M activity), while SCE calculates the O&M cost for TUG using the incremental operating cost, with the baseline bare wire cost incorporated as O&M savings, since TUG will completely avoid the baseline bare wire O&M. This inconsistency in how SCE uses the baseline bare wire O&M cost artificially lowers the BCR for CC below where it would be if SCE only incorporated incremental O&M costs for CC, as it does with TUG.

SCE's Use of Inconsistent Baselines for the Numerator and Denominator in the BCR for CC

The third of three issues SPD identifies in SCE's Chapter 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding" is an internal mismatch, within the CC calculation alone, between the baselines SCE uses for the numerator and denominator in calculating the BCR for CC.

---

[587] SCE response to Data Request SPD-SCE-2026 RAMP-010, Questions 28(a) and 28(a)(i).

[588] D.25-08-032, Appendix A, Row 25, p. A-19.

[589] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," p. WP-2.

As noted above, the RDF Phase 2 Decision requires the use of CBRs (now BCRs), defined as benefits divided by costs, so the numerator contains the benefits and the denominator contains the costs. [590] The baseline comparison case SCE uses to calculate its BCR for CC is different for the benefits (numerator) and costs (denominator), which likely understates CC's BCR, particularly relative to TUG, whose BCR reflects only incremental O&M, while CC's includes all O&M costs, including vegetation management already reflected in the No-Build Baseline... SCE measures the risk reduction benefits of CC in the numerator against a no-build baseline, reflecting the status quo, including existing O&M; it measures the costs against a no-infrastructure baseline, reflecting a world where there is no existing O&M. SCE confirmed that it takes this approach to calculating the BCR for CC through data request responses. SPD asked SCE to provide "[c]onfirmation that each BCR calculation uses a consistent baseline for both risk-reduction benefits and avoided O&M costs," and to clarify, "does the no-build baseline risk used to calculate risk reduction reflect the same level of O&M activity assumed when calculating avoided O&M costs (i.e., O&M savings) included in that BCR?"[591] SCE responded, "Yes, each BCR calculation is internally consistent with respect to baseline assumptions. The no-build baseline risk reflects system conditions inclusive of ongoing vegetation management activities, consistent with current program execution," thus confirming that SCE measures its numerator against a baseline where existing O&M continues.[592] As described above, the denominator for the BCR for CC includes that same existing O&M ($62K per mile per year) as though it were newly incurred by installing CC. If SCE was using a consistent baseline for the numerator and denominator, it would measure costs against a no-build baseline in the denominator, not a no-infrastructure baseline, including only incremental expenses made necessary by the capital investment. In that case, SCE's calculation of net O&M cost for CC would be the incremental expenses made necessary by the installation of CC minus the $15K O&M savings per mile per year SCE estimates it gains from the installation of CC. SPD cannot calculate this value using the established record, given that SCE has not determined CC's incremental O&M cost. SPD can, however, estimate bounds on what this value would be. The denominator would decrease by up to $62K per mile per year. If SPD corrects the apparent double counting in the BCR formula for TUG (see the description of the arithmetic error SPD identified in the TUG net O&M formula above), the TUG denominator would decrease by $7K per mile per year. The result of correcting these formulas would move the BCR in the same direction, but the change from the correction would differ by roughly an order of magnitude.

SPD is concerned about this because SCE selects hardening mitigations primarily based on BCR, prioritizing the mitigation with the highest BCR (as long as all options have a BCR of 1.0 or more). [593, 594] An

[590] D.22-12-027, Appendix A, Definitions, p. A-3; Rows 1-7, pp. A-9-A-10.

[591] Data Request SPD-SCE-2026 RAMP-004, Question 23(c).

[592] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 23(c).

[593] SCE 2026 RAMP Ch. 4, p. 1.

[594] SCE 2026 RAMP Ch. 4, Figure III-6 "BCR-Based Decision-Making Flow Chart," p. 42.

O&M input that systematically enlarges one mitigation's denominator relative to another's does not just impact the BCR of the given mitigation, it may also impact SCE's mitigation selection.

SPD finds the following about SCE's use of inconsistent baselines for the numerator and denominator in the BCR for CC:

25. In calculating the BCR for CC, SCE measures the risk reduction benefits of CC in the numerator against a no-build baseline, reflecting the status quo, including existing O&M while it measures the costs of CC against a no-infrastructure baseline, reflecting a world where there is no existing O&M. This means that SCE does not measure the benefit and cost components of the BCR for CC against the same baseline. This practice effectively skews the BCR for CC downward.

26. SCE's inconsistent way of incorporating the cost of O&M in its BCR calculations for CC and TUG (identified above) systematically increases the value of the denominator in the BCR calculation for CC but leaves the value of the denominator in the BCR calculation for TUG relatively unaffected, causing the BCR for CC to be lower than it would be under a baseline treatment consistent with SCE's treatment of the baseline in the BCR calculation for TUG. This discrepancy increases the BCR for TUG relative to the BCR for CC, possibly affecting SCE's prioritization of mitigations.

Discrepancies in SCE's Estimated Mitigation Benefits

SPD calculated that the SCE's risk score summary tables in its RAMP application present a combined annualized risk reduction of $301,860 thousand between the beginning of 2029 and the end of 2032 for both wildfire and PSPS.[595] SPD then applied the net present value (NPV) "Annuity Factor" formula SCE documents on the "Rates" tab of its Chapter 4 work paper "Wildfire Benefit Cost Ratio Calculations," using the WACC discount rate of 7.59 percent and SCE's inflation rate of 2.3 percent, a 55-year useful life, and a 2029 start date. By SPD's calculation, this yields a factor of 14.2302[596] and a total mitigation benefit of approximately $4.30 billion.[597] Because SCE assumes that 55 years is the longest possible useful life of an asset and SCE's earliest start date in the work paper is 2029, $4.30 billion is an upper bound on the system-level mitigation benefit implied by SCE's risk score summary tables in its RAMP application[598] using SCE's own methodology. SPD then summed the RRU mitigation benefits (WACC basis) SCE estimated for all

[595] SPD calculation using the risk totals in SCE 2026 RAMP Ch. 4, Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk," and Table I-3 "Summary of Pre- and Post-LoRE Risk Score for PSPS," p. 22.

[596] SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tab "Rates:" WACC scenario inputs (cells A4–F4: inflation 2.3%, discount rate 7.59%) and "NPV Annuity Factor" formula (cells A6–A8: Σ_{i=0}^{UL−1} (1+inf)^i / (1+dr)^(i + Start_Date − 2025)). Applying UL = 55 and Start_Date = 2029 yields a factor of 14.2302.

[597] SPD calculation: $301,860 thousand *14.23.

[598] SCE 2026 RAMP Ch. 4, Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk," and Table I-3 "Summary of Pre- and Post-LoRE Risk Score for PSPS," p. 22.

mitigations in the same work paper. That came to $17.26 billion, approximately four times SCE's upper-bound system-level mitigation benefit derived from SCE's own Tables I-2 and I-3.[599]

Table 1-8. Sum of RRU-Level Mitigation Benefit (WACC Basis) by Mitigation, Chapter 4 Work Paper "Wildfire Benefit Cost Ratio Calculations"[600]

RAMP ID	Mitigation	Mitigation Benefit (WACC)
C1	Wildfire Covered Conductor Program	$5,231,003,939
C2	Targeted Undergrounding	$4,703,205,021
C3	Fire Resistant Wrap Expanded Deployment	$64,546,570
C4	REFCL - Grounding Conversion	$194,432,175
C5	REFCL - Ground Fault Neutralizer	$6,379,508,903
C6	Distribution Early Fault Detection	$283,869,492
C7	Transmission Early Fault Detection	$139,618,695
C19	Transmission Proactive Splice Shunting	$53,891,386
M1	Sub-Transmission OH Conductor Replacement	$210,337,887
	Total	**$17,260,414,069**

When SPD directly asked SCE to explain the discrepancy between the total mitigation benefit SCE presents in its risk score summary tables in its RAMP application and the sum of mitigation benefits (WACC basis) SCE estimated for all mitigations in its Chapter 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, SCE replied that the risk score summary table values are "annualized risk numbers and are not comparable to the full mitigation benefits over the useful life of the asset (which varies by asset/mitigation)" and that SPD should not assume "all wildfire program benefits represent incremental reductions to baseline wildfire risk," adding that "[o]nly Covered Conductor and Targeted Undergrounding are modeled as directly reducing the underlying baseline wildfire ignition risk."[601] Even accepting SCE's position that only these two mitigations reduce baseline wildfire ignition risk while the remaining programs preserve existing

[599] SCE 2026 RAMP Ch. 4, Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk," and Table I-3 "Summary of Pre- and Post-LoRE Risk Score for PSPS," p. 22.

[600] SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet.

[601] SCE response to to Data Request SPD-SCE-2026 RAMP-010, Question 4(a).

performance or manage consequence and PSPS risk, by SPD's calculation their combined benefit of approximately $9.9 billion still exceeds the approximately $4.30 billion system-level benefit derivable from SCE's risk score summary tables for combined wildfire and PSPS risk. Because both figures purport to measure the risk-reduction benefit of the same proposed plan on a WACC basis, SPD should be able to reconcile them.

SPD finds the following about SCE's estimated mitigation benefits discrepancies:

27. SPD cannot reconcile the sum of RRU-level mitigation benefits SCE reports in its "Wildfire Benefit Cost Ratio Calculations" work paper ($17.26 billion)[602] with the system-level risk reduction SCE reports in the risk score summary tables in its RAMP application ($4.30 billion).[603] The sum of benefits from SCE's work paper is approximately four times the upper bound SPD can derive from SCE's risk score summary tables. In the work paper, the estimated benefits of two mitigations, CC and TUG, each independently exceed that system-level upper bound, at $5.23 billion and $4.70 billion respectively. However, SCE provided no explanation of how to reconcile the totals SPD derived from the RAMP application's risk score summary tables with the totals SPD derived from the risk score summary tables. Until SPD reconciles this discrepancy, it cannot rely on SCE's estimate of RRU-level mitigation benefits as a measure of the system-level risk reduction offered by SCE's proposed plan. All the BCRs SCE estimated for individual RRUs using those benefits are subject to the same overstatement.

Discrepancies in SCE's Estimated Mitigation Costs

If SPD applies a matched-scope basis (454.9 circuit miles[604] and 455 circuit miles for CC; 189.44 circuit miles and 189 circuit miles for TUG),[605] the total per-circuit-mile costs SCE reports in its "Wildfire Benefit Cost Ratio Calculations" work paper diverge in opposite directions from those SCE reports for the same mitigations in its RAMP application.[606] For CC, the work paper reports total cost of about $848.4 million

602 SPD calculation using SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet.

603 SPD calculation using SCE 2026 RAMP Ch. 4, Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk," and Table I-3 "Summary of Pre- and Post-LoRE Risk Score for PSPS," p. 22. SPD calculation is annualized over the asset's life using SCE's own documented NPV factor, deriving a total mitigation benefit of at most approximately $4.30 billion.

604 SCE's Wildfire Benefit Cost Ratio Calculations work paper uses "work unit," which SPD glosses as "circuit mile" for CC and TUG.

605 For work units, SPD calculation by summing across all rows using SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tabs "WF-C1-CoveredConductor" and "WF-C2-TargetedUndergrounding," column "Total Work Units." Circuit miles per SCE 2026 RAMP Ch. 4, Table VII-33 "Proposed Plan Programmatic Wildfire Estimated Unit Deployments, p. 77.

606 SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

($1.865 million per circuit mile),[607] compared to total cost of about $467.4 million ($1.027 million per circuit mile) per SCE's RAMP application,[608] which SPD calculates to be approximately $838 thousand per mile higher.

For targeted undergrounding, the work paper reports $754.7 million ($3.984 million per circuit mile)[609] compared to the total cost of $889.7 million ($4.707 million per mile)[610] SCE reports in its RAMP application, which SPD calculates to be approximately $724 thousand per mile lower. This pattern is consistent with how SCE incorporates full bare wire O&M cost into the BCR denominator for CC while including only TUG's own O&M cost and netting outs savings from avoided bare wire O&M cost in the BCR denominator for TUG (effectively decreasing the BCR for CC relative to TUG, described further above).[611] Table 1-9 presents a comparison of the per circuit mile cost of CC and TUG.

[607] Work paper calculation: for the Wildfire Covered Conductor Program (C1) 2029-2032, SCE estimates total costs of $848,371,386, per SPD calculation summing all rows in SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tab "WF-C1-CoveredConductor," column "Total Costs (WACC)." On this basis and the work units SCE estimates for C1 2029-2032, calculated as 454.9 (per SPD calculation summing all rows in the same work paper, column "Total Work Units"), SPD calculates the unit cost for CC to be about $1.865 million per work unit.

[608] RAMP application calculation: for the Wildfire Covered Conductor Program (C1) 2029-2032, SCE estimates total costs of $467,351 thousand in SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80. On this basis and the circuit miles SCE estimates for C1 2029-2032, 455, in the RAMP application (SCE 2026 RAMP Ch. 4, Table VII-33 "Proposed Plan Programmatic Wildfire Estimated Unit Deployments, p. 77), SPD calculates the unit cost for CC to be about $1.027 million per circuit mile.

[609] Work paper calculation: for Targeted Undergrounding (C2) 2029-2032, SCE estimates total costs of $754,709,904, per SPD calculation summing all rows in SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tab "WF-C2-TargetedUndergrounding" column "Total Costs (WACC)." On this basis and the work units SCE estimates for C2 2029-2032, calculated as 189.44 (per SPD calculation summing all rows in the same work paper, column "Total Work Units"), SPD calculates the unit cost for TUG to be about $3.984 million per work unit.

[610] RAMP application calculation: for Targeted Undergrounding (C2) 2029-2032, SCE estimates total costs of $889,737 thousand per SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80. On this basis and the circuit miles SCE estimates for C2 2029-2032, 189, in the RAMP application (SCE 2026 RAMP Ch. 4, Table VII-33 "Proposed Plan Programmatic Wildfire Estimated Unit Deployments, p. 77), SPD calculates the unit cost for TUG to be about $4.707 million per circuit mile.

[611] SCE 2026 RAMP Ch. 4 work paper "BCR Methodology for Covered Conductor and Targeted Undergrounding," pp. WP-2-WP-3.

Table 1-9. SPD Comparison of Per Circuit Mile Cost of CC and TUG from SCE's Wildfire BCR Calculations Work Paper and RAMP Application[612, 613]

Data Source (Scope or Cost)	Wildfire Covered Conductor Program (C1)	Targeted Undergrounding (C2)
Work paper scope ("work units" glossed as circuit miles)	454.90	189.44
RAMP application scope (circuit miles)	455	189
Work paper total cost	$848,371,386	$754,709,904
Work paper cost per circuit mile	$1.865M	$3.984M
RAMP application total cost	$467,351,000	$889,737,000
RAMP application cost per circuit mile	$1.027M	$4.708M
Cost difference (work paper – RAMP application)	**+$381,020,386**	**−$135,027,096**
Cost per circuit mile difference (work paper – RAMP application)	**+$838K**	**−$724K**
Direction of change	Work paper **higher**	Work paper **lower**

As shown in Table 1-9, by SPD's calculation applying a matched-scope basis, the total cost SCE loaded into the BCR work paper exceeds the RAMP application's total cost for CC by approximately $838 thousand per circuit mile but falls below the total cost for TUG by approximately $724 thousand per mile.

SPD finds the following about SCE's estimated mitigation costs discrepancies:

28. SCE's total costs for CC and TUG in its Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" diverge in opposite directions from the total costs SCE reports in its RAMP application.[614] On a matched-scope basis, the total cost SCE loads into the BCR work paper for CC

[612] SPD calculations using SCE 2026 RAMP Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" spreadsheet, tabs "WF-C1-CoveredConductor" and "WF-C2-TargetedUndergrounding."

[613] RAMP application source: SCE 2026 RAMP Ch. 4, Table VII-33 "Proposed Plan Programmatic Wildfire Estimated Unit Deployments, p. 77, and Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

[614] SCE 2026 RAMP Ch. 4, Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

exceeds its RAMP application total cost by approximately $838 thousand per mile ($1.865 million versus $1.027 million per mile), while the total cost in the BCR work paper for TUG falls below RAMP application total cost by approximately $724 thousand per mile ($3.984 million versus $4.708 million per mile). This pattern is consistent with the CC BCR denominator carrying an added O&M component while the TUG denominator carries an O&M credit, the same directional asymmetry in O&M treatment reflected in SCE's net O&M formulas for the two mitigations. Because the O&M component enters the BCR denominator, this asymmetry raises the estimated cost for CC relative to a consistent treatment and lowers the estimated cost for TUG, biasing the relative BCR comparison between the two mitigations.

SCE's BCR Calculation Method for CC with REFCL

To better understand how SCE allocates costs related to the installation of REFCL, SPD asked SCE, "For BCR calculations involving REFCL (including combinations of covered conductor and REFCL), is the substation-level REFCL cost allocated only to the HFRA portion of the downstream RRU served or is it spread across the total mileage of all RRUs and circuits served by the substation, including areas outside the HFRA?"[615] SCE clarified that the cost is allocated consistent with SCE's practice with other wildfire mitigations, such that "substation-level REFCL costs are allocated only to the HFRA portions of the downstream RRUs served," adding that "[w]hile non-HFRA segments may also be exposed to wildfire, safety, and reliability risks, these risks are not included in the quantified wildfire benefit calculation or associated cost allocation."[616] In response to another data request question, SCE provided an example of a BCR calculation for a combination of CC and REFCL for the Isabella substation, demonstrating the calculations related to the treatment of REFCL costs described above.[617]

After examining SCE's treatment of REFCL costs in the example of the Isabella substation, SPD identified five concerns with this approach regarding the calculation of the BCR for CC with REFCL.

1. The REFCL substation cost is blended with CC cost into a single per-mile rate.

In its data request response, SCE reported that the Isabella substation maps to four circuits, and it allocated $1,100,727.36 to each circuit.[618] SPD notes that this appears to be a per-mile cost rate, not a per-circuit allocation.[619] SCE appears to calculate this rate combining the CC per-mile cost and the $16 million substation REFCL cost and spreading it across the total HFRA miles of the substation's four circuits. In the

[615] Data Request SPD-SCE-2026 RAMP-004, Question 29.

[616] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 29.

[617] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 32.

[618] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 32.

[619] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 32, attachment "Excel_REFCL_Calculation.xlsx."

terms of the spreadsheet SCE provided with its data request response, SCE appears to use this formula to calculate the cost per mile of CC with REFCL:[620]

REFCL_CC_cost_per_mile = (REFCL_cost_per_substation + CC_cost_per_mile × ΣHFRA miles) ÷ ΣHFRA miles

This formula reduces to:

REFCL_CC_cost_per_mile = CC_cost_per_mile + (REFCL_cost_per_substation ÷ ΣHFRA miles)

Accordingly, SCE appears to multiply this rate by the HFRA miles of each circuit to calculate the cost of CC with REFCL for each circuit.

The substation's four circuits include a total of 158.813 HFRA miles, so the REFCL component of the blended rate is $16,000,000 ÷ 158.813 = $100,747.48 per mile, or 9.2 percent of the $1,100,727.36 total. The CC component is $999,979.88 per mile, or 90.8 percent.[621] Because SCE combines the CC and REFCL costs into a single rate, SCE cannot report the REFCL cost separately.

2. This blended BCR approach does not allow SCE to calculate a BCR for REFCL alone.

SCE cannot evaluate the BCR for REFCL because both the cost and the benefit terms combine the cost of REFCL with CC through the per-mile rate described above and the benefit through a single per-circuit mitigated-risk value.[622] SCE appears to have no way to calculate the incremental value of adding REFCL to CC. SCE has not demonstrated that REFCL passes a benefit-cost test on its own, only that REFCL paired with covered conductor does. This is consequential because a highly cost-effective covered-conductor investment can carry a marginal REFCL investment above the BCR threshold that REFCL would not meet independently SPD is concerned that because there is no BCR for REFCL alone, only a BCR for CC with REFCL, SCE might invest in REFCL installations with low BCRs when it should invest in alternative projects with higher BCRs, including CC alone or CC with REFCL on other circuits. SPD's concern is not hypothetical: approximately 91 percent of the blended cost is from CC, so the BCR for CC with REFCL is numerically dominated by the CC investment and would be close to the BCR for CC alone.

3. SCE incorporates the full substation cost in the BCR while excluding benefits to areas outside the HFRA, though REFCL provides service to the entire system.

---

[620] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 32, attachment "Excel_REFCL_Calculation.xlsx," tab "Input_Values," column "REFCL_CC_cost_per_mile."

[621] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 32, attachment "Excel_REFCL_Calculation.xlsx," tab "Input_Values," columns "REFCL_cost_per_substation," "CC_cost_per_mile," and "REFCL_CC_cost_per_mile"; tab "BCR," column "HFRA_Miles."

[622] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 32, attachment "Excel_REFCL_Calculation.xlsx," tab "Input_Values," column "REFCL_CC_cost_per_mile."

After installation at the substation, REFCL protects the entire downstream network, including circuit segments outside the HFRA. In the data request response referenced above, SCE confirmed that REFCL provides benefits outside the HFRA on circuit segments that are exposed to wildfire, safety, and reliability risk, but that SCE doesn't include either these risks or the benefits REFCL provides in its calculations.[623] The result is an asymmetry: the BCR absorbs the full cost of REFCL, but it includes only the risk reduction from REFCL that occurs in the HFRA.

4. The combined BCR may include risk reduction from REFCL with CC that SCE already achieved with CC alone before the REFCL scope year (e.g., risk reduction SCE may have already counted).

SCE's formula for calculating the BCR for CC with REFCL includes a single value for risk mitigated by CC with REFCL in the benefit term, not disaggregating the risk that SCE may have already mitigated with CC alone. Where SCE has already installed CC, it has already realized risk reduction from that installation, and the associated reduction in risk should be reflected in the circuit's risk profile. Including that previous risk reduction in the benefit term of the BCR for CC with REFCL on that circuit would credit the addition of REFCL on existing CC with a benefit that is not fully attributable to the addition of REFCL. To the extent that SCE has already accounted for the risk reduction from CC alone in the BCR for that CC installation, including the benefit from that risk reduction in the BCR for adding REFCL on existing CC would effectively mean SCE was counting that benefit twice.

5. On half of the circuits where SCE calculates a BCR for both CC and REFCL, SCE estimates a lower mitigation benefit for CC with REFCL than for CC alone, notwithstanding a larger modeled risk reduction.

In response to a request for information on SCE's proposed RRUs, SCE indicated 40 RRUs include both CC and CC with REFCL mitigations.[624] SCE estimated a lower mitigation benefit (using the WACC discount rate scenario) for CC with REFCL than for CC alone on 20 of those RRUs, with the mitigation benefit for CC with REFCL ranging from 19.8 percent (Meadowlark) to 95.5 percent (Birchim) of the benefit for CC alone.[625] For the 40 RRUs that SCE reports as separate CC and CC with REFCL projects, SCE indicated the same total work units (circuit miles) for both, so the difference does not arise from a difference in mitigation scope.[626] The difference also does not arise from SCE's underlying risk model, given that SCE estimates more risk reduction for the CC with REFCL project than for the CC project in all 40

[623] SCE response to Data Request SPD-SCE-2026 RAMP-004, Questions 29 and 31.

[624] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 33, attachment "SPD-SCE-2026RAMP-004_Question33.xlsx," tab "Combined," columns "Proposed and Alternative Mitigations."

[625] SPD calculation using SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 33, attachment "SPD-SCE-2026RAMP-004_Question33.xlsx," tab "Combined," columns "Proposed and Alternative Mitigations" and "Mitigation Benefit (WACC Calc)."

[626] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 33, attachment "SPD-SCE-2026RAMP-004_Question33.xlsx," tab "Combined," columns "Proposed and Alternative Mitigations" and "Total Work Units."

RRUs.[627] SPD sees the inconsistency exclusively in SCE's conversion of modeled risk reduction into estimated mitigation benefit. SPD subtracted post-mitigated risk from pre-mitigated risk and divided SCE's estimated mitigation benefit by that number to derive an implied present-value factor.[628] For the CC installation assigned to RRUs with both CC and CC with REFCL, SPD calculates this factor to fall within a narrow band of 11.4260 to 14.2302 and varies only with project start year, consistent with the discounting convention SCE applies elsewhere. For the CC with REFCL installations assigned to RRUs with both CC and CC with REFCL, SPD calculates this factor to range from 2.3773 to 14.0526. The factor differs for CC and CC with REFCL in all 40 RRUs where SCE reports separate CC and CC with REFCL projects.

To illustrate an instance where there is a lower mitigation benefit for CC with REFCL than for CC alone, Table 1-10 presents SCE's modeled risk reduction, estimated mitigation benefit, and the implied present-value factor calculated by SPD for the Meadowlark RRU, which SCE has targeted for installation of both CC and CC with REFCL, indicating the same start year and same pre-mitigated risk for both.

Table 1-10. Meadowlark: Comparison of Modeled Risk Reduction and Estimated Mitigation Benefit, Covered Conductor Alone vs. Covered Conductor with REFCL[629]

Mitigation	Start Year	Pre-Mitigated Risk	Post-Mitigated Risk	Modeled Risk Reduction	Reported Mitigation Benefit (WACC)	Implied Present-Value Factor	BCR (WACC)
Proposed – Covered Conductor	2031	751,765.46	328,002.30	423,763.16	$5,209,439	12.2933	33.48
CC + REFCL From Alternatives	2031	751,765.46	318,104.54	433,660.92	$1,030,949	2.3773	4.58

[627] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 33, attachment "SPD-SCE-2026RAMP-004_Question33.xlsx," tab "Combined," columns "Proposed and Alternative Mitigations," "Pre Mitigated Risk," and "Post Mitigated Risk."

[628] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 33, attachment "SPD-SCE-2026RAMP-004_Question33.xlsx," tab "Combined," columns "Proposed and Alternative Mitigations," "Pre Mitigated Risk," "Post Mitigated Risk," and "Mitigation Benefit (WACC Calc)."

[629] SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 33, attachment "SPD-SCE-2026RAMP-004_Question33.xlsx," tab "Combined," columns "Proposed and Alternative Mitigations," "Pre Mitigated Risk," "Post Mitigated Risk," "Mitigation Benefit (WACC Calc)," "Benefit Cost Ratio (WACC Calc)."

According to SCE's calculations, adding REFCL to the Meadowlark CC project increases the modeled risk reduction by 2.3 percent while decreasing the reported mitigation benefit by 80.2 percent.[630] The same pattern, in varying magnitude, appears across the 20 RRUs for which SCE estimated a lower mitigation benefit (WACC) for CC with REFCL than for CC alone.

Because SCE does not derive the estimated benefit for CC with REFCL from the modeled risk reduction on the same basis as it does for CC alone, the two figures are not comparable, and the BCRs for CC with REFCL SCE reported in its data request response cannot be used to evaluate whether adding REFCL to a CC project is cost-effective.

SPD finds the following about SCE's BCR calculation method for CC with REFCL:

29. SCE's method of blending the costs and benefits for CC and REFCL when estimating BCRs for CC with REFCL does not allow it to calculate a BCR for REFCL alone. This means SCE cannot demonstrate whether adding REFCL meets SCE's minimum BCR threshold (1.0) separately from CC alone. SPD is concerned that SCE might install CC with REFCL in instances where CC alone would be highly cost-effective, and REFCL would not add enough benefit to change prioritization decisions. SCE cannot assess the marginal value of adding REFCL to circuits scheduled for, or that have already received, CC installation. SPD is further concerned that the BCR for CC with REFCL may credit REFCL with risk reduction already achieved by prior CC installation, effectively counting the same risk-reduction benefit twice.

30. SCE deploys REFCL at the substation level where it can provide risk reduction benefits to all downstream circuits, both within and outside SCE's HFRA. SCE includes the full REFCL cost, including cost outside the HFRA, in its BCR calculation for CC with REFCL, but does not include risks to circuits outside the HFRA, including wildfire, safety, and reliability risks, or the risk-reduction benefits of REFCL outside the HFRA when calculating the BCR for CC with REFCL. This creates a potential asymmetry between costs and benefits in SCE's BCR calculation for CC with REFCL.

31. SCE proposes both CC and CC with REFCL mitigations for 40 RRUs and in 20 of those cases estimates a lower mitigation benefit (WACC basis) for CC with REFCL than for CC alone, even though the work units are identical and SCE estimates a larger risk reduction for the CC with REFCL investments. SCE's underlying risk model doesn't explain the difference, given that SCE estimates more risk reduction for RRUs with both CC and CC with REFCL than for RRUs with just CC. SPD sees the inconsistency exclusively in SCE's conversion of modeled risk reduction into estimated mitigation benefit. For all 40 cases where SCE proposes both mitigations, the implied

[630] SPD calculation using SCE response to Data Request SPD-SCE-2026 RAMP-004, Question 33, attachment "SPD-SCE-2026RAMP-004_Question33.xlsx," tab "Combined," columns "Proposed and Alternative Mitigations," "Pre Mitigated Risk," "Post Mitigated Risk," and "Mitigation Benefit (WACC Calc)."

present-value factor differs between CC with REFCL and CC alone, falling as low as 2.38 for CC with REFCL compared to a range of 11.43 to 14.23 for the CC alone.

BCRs of Customer-Facing PSPS Programs

SCE's ten customer-facing PSPS programs (risk controls C1 through C10) have BCRs that do not meet SCE's 1.0 minimum threshold for grid hardening mitigations to address wildfire risk. [631, 632] Table 1-11 presents the ten PSPS controls with SCE's estimated BCRs in the proposed plan, which has an overall BCR of 0.22 (WACC basis). SCE presents additional and more granular information about its PSPS controls in several work papers, including one that breaks down mitigation effectiveness of PSPS controls by safety, reliability, and financial consequences[633] and one that explains SCE's likelihood and consequence calculation methodology for PSPS risk.[634]

SCE's customer-facing PSPS programs cannot be justified using BCRs alone. SCE notes that, "[a]lthough certain PSPS customer-facing programs yield relatively low BCRs the Commission has continued to emphasize the importance of maintaining and enhancing these measures to address stakeholder concerns. In Phase 3 of the PSPS OIR (D.21-06-034, p. 115), the Commission explicitly recognized the need for utilities to improve mitigation of impacts on all customers with particular focus on access and functional needs and vulnerable populations. This direction reflects the expectation that SCE will sustain engagement with affected communities and continue investing in PSPS mitigation, regardless of program BCR outcomes."[635]

631 SCE 2026 RAMP Ch. 4, Table XIII-61 "Proposed Plan Programmatic PSPS Estimated Spend ($000s) and Benefit-Cost Ratios," p. 120.

632 SCE 2026 RAMP Ch. 4, p. 1.

633 SCE 2026 RAMP Ch. 4 work paper "PSPS Mitigation Effectiveness" spreadsheet.

634 SCE 2026 RAMP Ch. 4 work paper "PSPS Overall Residual Risk."

635 SCE 2026 RAMP Ch. 4, p. 120, footnote 106.

Table 1-11. PSPS Proposed Estimated Program Costs and BCRs (2029-2032)($000s)[636]

Control ID	Control Name	O&M Costs	Capital Costs	Total Costs	BCR (WACC)	BCR (Societal)	BCR (Hybrid)
C1	Customer Resource Center (CRC) / Community Crew Vehicle (CCV)	$31,478		$31,478	0.32	0.32	0.34
C2	Critical Care Backup Battery (CCBB)	$41,198		$41,198	0.21	0.22	0.22
C3	Community Resiliency Programs Equipment Rebates (Portable Power Stations and Generators)	$6,435		$6,435	0.90	1.03	0.99
C4	211 Partnerships (PSPS 211 Service)	$11,443		$11,443	0.05	0.06	0.06
C5	In-Event Battery Loan Pilot	$1,501		$1,501	0.15	0.15	0.16
C6	Resiliency Zone Sites	$5,685		$5,685	0.05	0.05	0.05
C7	Permanent Home Battery Storage Rebate	$9,249		$9,249	0.08	0.10	0.09
C8	Fully Subsidized Permanent Home Battery Backup Pilot	$11,006		$11,006	0.02	0.03	0.03
C9	K-12 Schools Backup Power Systems Rebate Pilot	$3,099		$3,099	0.06	0.09	0.07
C10	Senior Care Facilities Backup Power Systems Rebate Pilot	$1,100		$1,100	0.05	0.09	0.06
	Total	**$122,193**	**$0**	**$122,193**	**0.22**	**0.23**	**0.23**

[636] SCE 2026 RAMP Ch. 4, Table XIII-61 "Proposed Plan Programmatic PSPS Estimated Spend ($000s) and Benefit-Cost Ratios," p. 120.

SPD finds the following about SCE's customer-facing PSPS programs:

32. All ten of SCE's proposed customer-facing PSPS programs have low BCRs, with SCE estimating an overall BCR of 0.22 (WACC basis) for its proposed plan for mitigating PSPS risk. These programs cannot be justified on cost-effectiveness grounds. SCE's stated basis for funding them is mandate and Commission direction to sustain programs that support vulnerable populations and those with access and functional needs, "regardless of program BCR outcomes."

Idle and Out-Of-Service Facilities and Transmission Ignition Risk

SPD added the following section in response to the Eastmont Fire finding of August 2026.[637]

SPD finds the following about SCE's idle and out-of-service facilities and transmission ignition risk:

33. Idle and out-of-service facilities have no modeled ignition pathway. SCE calibrates POI to the historical ignition record (FIPA, 2019-2024)[638] and quantifies wildfire risk through the ignition drivers in its risk bow tie (the drivers are contact from object, equipment or facility failure, wire-to-wire contact, and other or unknown causes).[639, 640] The model contains no driver or POI pathway calibrated to capture ignition from an idle or out-of-service facility: SCE addresses such facilities only as an "emergent risk driver" under ongoing study,[641] notwithstanding that they may fall within the geographic limits of SCE's wildfire risk scope (i.e., SCE's HFRA).[642]

34. SCE acted separately on idle-facility ignition risk operationally before filing its 2026 RAMP application. In correspondence dated February 6, 2025, SCE reported strengthening its grounding practices for idle transmission lines, including updates to its Transmission Operations and Maintenance Policies and Procedures, more than a year before its 2026 RAMP application filing (May 15, 2026).[643] SCE's 2026 RAMP application does not include a corresponding treatment of idle-facility ignition risk in its risk quantification or mitigation portfolio.

35. SCE reports wildfire risk as a single combined total rather than disaggregated by asset class. The SCE 2026 wildfire risk bow tie describes the exposure as approximately 9,300 miles of overhead primary distribution conductor and approximately 4,400 miles of overhead transmission facilities within the HFRA.[644] SCE meanwhile aggregates risk additively to a single system-wide LoRE, CoRE,

---

[637] South Pasadenan article "Eaton Fire Investigation Concludes: Electrical Arcing on Idle Edison Tower Caused the Catastrophic Blaze That Killed 19 & Wiped Out Altadena" (Aug. 4, 2026) (https://southpasadenan.com/eaton-fire-investigation-concludes-electrical-arcing-on-idle-edison-tower-caused-the-blaze-that-killed-19/, accessed Aug. 5, 2026).

[638] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions," p. WP-2.

[639] SCE 2026 RAMP Ch. 4, Figure II-4 "Risk Bowtie for Wildfire Risk," p. 25.

[640] SCE 2026 RAMP Ch. 4 work paper "Wildfire Mitigation Effectiveness" spreadsheet, tab "Wildfire Summary," column "Subdriver/ Consequence Type."

[641] SCE 2026 RAMP Ch. 4, p. 17, footnote 31.

[642] SCE 2026 RAMP Ch. 4, Table II-4 "Wildfire Risk Scope," p. 24.

[643] SCE correspondence submitted to CPUC Wildfire Safety Enforcement Branch re: Eaton Fire, submitted under Publice Utilities Code section 315 and Resolution ESRB-12, Feb. 6, 2025 (Submission No. 202500250), p. 4, footnote 1 (https://download.edison.com/406/files/202502/section-315-20250206-eaton-fire.pdf, accessed Sept. 8, 2026).

[644] SCE 2026 RAMP Ch. 4, Figure II-4 "Risk Bowtie for Wildfire Risk," p. 25.

and risk score.[645] SCE nonetheless distinguishes transmission from distribution when calculating wildfire risk, attributing different likelihood coefficients to Condition 1, 2, and 3 for each side of SCE's system.[646, 647] SCE's 2026 RAMP application reports no transmission-specific risk quantity, although SCE calculates wildfire risk for its transmission facilities.

[645] SCE 2026 RAMP Ch. 4, Table I-2 "Summary of Pre- and Post-LoRE Risk Score for Wildfire Risk," p. 22.

[646] SCE response to Data Request SPD-SCE-2026RAMP-006, Question 4.

[647] SCE 2026 RAMP Ch. 4 work paper "Conditional Probability of Ignition Assumptions."

Summary of Findings

SPD finds the following:

Risk Description

1. While SCE limits its wildfire risk scope to overhead distribution and transmission assets within SCE's HFRA, there may be grounds for including underground assets and assets located outside the HFRA in its risk scope.
2. SPD is concerned that SCE's social vulnerability scalar that it applies to the monetized value of fatalities and serious injuries increases with the absolute number of AFN and NRCI customers on a circuit, and therefore with circuit size, meaning the scalar appears to capture circuit size as much as differential vulnerability, raising a double-counting concern.
3. SPD is concerned about how SCE incorporates qualitative IWMS components directly into its monetized risk scores, converts them into scalars (AFN, NRCI, and CFRA), and applies them to its baseline risk modeling outputs, potentially distorting the true picture of risk. Because these adjustments are embedded in the risk values that feed SCE's BCRs, the resulting scores no longer reflect modeled loss alone, and SCE does not make the share of risk attributable to the scalars visible. Of particular concern is the CFRA scalar, which has the largest effect, raising monetized safety consequences by approximately 55.6 to 100 percent wherever it applies, with no intermediate values.
4. SPD is concerned that SCE's ICE Calculator inputs are based on a dataset that excludes MEDs, such that catastrophic conditions may not be incorporated into SCE's calculations.
5. SCE has not shown that its calculations of per-CMI values hold for outages several times longer than those that it simulates in wildfire scenarios.
6. SPD is concerned that SCE's application of the ICE Calculator values as fixed class-average values results in circuit-level variation in monetized reliability value being driven solely by customer class mix rather than event-specific outage characteristics.
7. SPD is concerned that SCE's calculation of the monetized reliability benefit is driven almost entirely by the non-residential load and is comparatively insensitive to the load of residential customers, the most common customer classification in SCE's HFRA.

Tranches

8. SPD did not find a segment-to-tranche crosswalk or any way to trace any mitigation segment to its corresponding risk tranche from SCE's RAMP application or work papers.
9. SPD is concerned that SCE's assignment of RRUs to risk tranches don't consistently align with estimated mitigation benefits and isn't satisfied with SCE's explanation of why the tranche level and mitigation benefits diverge.
10. SPD is concerned that does not assign some RRUs with substantial reported wildfire risk to risk tranches, only assigning RRUs that it already selected for mitigation to tranches, defeating the purpose of using tranching to prioritize assets for mitigation.

11. SPD is unable to verify from SCE's RAMP application and work papers that SCE's tranching framework supports the prioritization function SCE attributes to it.

RRUs

12. SPD is concerned that SCE does not model wildfire risk from secondary and service lines, only modeling risk for the portions of a circuit where it intends to mitigate risk, while including the cost of hardening secondary and service lines in its spend and per-mile figures.
13. Although SCE states that cost and benefit must cover the same assets in a BCR calculation, SCE includes hardening cost for secondary and service lines in spend and per-mile metrics but excludes their ignition risk from its POI model and circuit rankings.

Risk Driver Frequencies

14. SCE reported in a data request response a 2.6 times higher ignition frequency for the equipment/facility failure driver than the frequency it reports for that driver over the same period in the same location (HFRA) in its RAMP application, raising the concern that SCE's POI—part of every wildfire risk mitigation BCR calculation— is calibrated to one of these frequencies, but it isn't clear which one.
15. SPD is concerned that SCE calibrates its 2029 no-build baseline on an historical average not normalized to incorporate completed hardening work, creating a no-build baseline that may overstate 2029 ignition frequency, which in turn may inflate BCRs throughout SCE's portfolio of mitigations.

Consequences

16. SCE may either over- or underestimate an ignition's risk due to its ignition classification system being out of alignment with the consequence its model predicts, as evidenced when SPD's calculation of financial consequences for a set of SCE's historical Condition 3 ignitions in the HFRA came out to be much less than the consequence value that SCE assigns using its WIM.
17. SCE's use of the unreliable FIPA HFRA ignition count over 2020-2024 to calibrate its POI model may overemphasize drivers inherently less likely to lead to ignition spread while underweighting wind-related drivers more likely to fail in the high-wind conditions associated with many of California's catastrophic wildfires.
18. In updating its WIM by adding inputs from FireSight 8 and RMS 2.0, scaling asset-level values toward the coarser RMS 2.0 distribution and truncating at the RMS 2.0 hexagon maximum rather than its expected value, SCE has not demonstrated that the aggregate of the scaled asset-level expected values reconciles to, and does not exceed, the RMS 2.0 hexagon-level expected value SCE intends the scaling to respect.
19. SCE has not validated that its WIM is predictive of consequence and its stated validation position is internally inconsistent.

Controls and Mitigations

20. SCE's inspection and vegetation management controls have low BCRs though they collectively represent approximately $2.59 billion in proposed 2029-2032 spend, and although low-BCR programs may be necessary to meet compliance requirements, portions of these programs exceed the minimum activity necessary for compliance, and SCE has not separately shown the cost-effectiveness of the discretionary scope above that compliance floor.

Alternatives Analysis

21. SCE's Alternative Plan 2 for wildfire risk mitigation adds 37 miles of TUG, including in areas where it would be replacing CC with TUG, but SCE's estimated risk reduction from TUG under Alternative Plan 2 is far greater than in the proposed plan, although replacing CC with TUG should result in less risk reduction than replacing bare wire with TUG.

BCR Calculations

22. SCE's net O&M formula for TUG counts the new TUG O&M cost twice within the same formula, both subtracting it from the baseline and adding it as the new operating cost.
23. Lacking a cost estimate for CC O&M, in its BCR for CC SCE uses a proxy cost—its estimate of $62K per mile per year existing bare wire overhead infrastructure O&M cost—meanwhile applying this $62K O&M cost as an avoided O&M cost, or O&M savings, in the BCR for TUG.
24. SCE should not include the $62K baseline in the O&M cost for CC, only incremental cost introduced by the installation of CC, per the RDF Phase 4 Decision.
25. SCE does not measure the benefit and cost components of the BCR for CC against the same baseline, using a no-build baseline in the numerator (benefit) and a no-infrastructure baseline in the denominator (cost), effectively skewing the BCR for CC downward.
26. SCE's inconsistent way of incorporating the cost of O&M in its BCR calculations for CC and TUG increases the BCR for TUG relative to the BCR for CC, possibly affecting SCE's prioritization of mitigations.
27. SPD cannot reconcile the sum of RRU-level mitigation benefits SCE reports in its "Wildfire Benefit Cost Ratio Calculations" work paper with the system-level risk reduction SCE reports in the risk score summary tables in its RAMP application, with the work paper benefits appearing to be about four times the upper bound for benefits per SCE's risk score summary tables.
28. SCE's total per-mile costs for CC and TUG are far higher in its Ch. 4 work paper "Wildfire Benefit Cost Ratio Calculations" than the total per-mile costs SCE reports in its RAMP application, potentially biasing the relative BCR comparison between the two mitigations.
29. Given that SCE cannot calculate a BCR for REFCL alone, SPD is concerned SCE might install CC with REFCL in instances where CC alone would be highly cost-effective, with REFCL not adding enough benefit to make a difference in prioritization decisions. Also, SPD is concerned the BCR for CC with REFCL may credit REFCL with risk reduction that was already achieved by prior installation of CC alone.

30. In SCE's calculation of the BCR for CC with REFCL, SCE includes the full cost of REFCL both within and outside the HFRA, but doesn't include either the risk or risk reduction benefits of REFCL outside the HFRA in its calculation.
31. SCE estimates a lower benefit for CC with REFCL than for CC alone in 20 RRUs out of 40 RRUs where SCE proposes both CC and CC with REFCL, even with identical work units and CC with REFCL having a larger risk reduction benefit, evidence of a possible problem with SCE's conversion of modeled risk reduction into estimated mitigation benefit.
32. SCE's proposed customer-facing PSPS programs have low BCRs, with SCE justifying them as required by Commission direction to sustain programs that support vulnerable populations and those with access and functional needs.

Idle and Out-of-Service Facilities and Transmission Ignition Risk

33. SCE does not model the ignition pathway for idle and out-of-service facilities, addressing such facilities only as an "emergent risk driver" under ongoing study, notwithstanding that they may fall within the geographic limits of SCE's wildfire risk scope (i.e., SCE's HFRA).
34. In February 2025, SCE informed the Commission that it was strengthening its grounding practices for idle transmission lines, including updates to its Transmission Operations and Maintenance Policies and Procedures, more than a year before its 2026 RAMP application filing, which does not include a corresponding treatment of idle-facility ignition risk in its risk quantification or mitigation portfolio.
35. SCE's 2026 RAMP application does not report wildfire risk for transmission facilities although it calculates wildfire risk for its transmission facilities.

Recommendations to Address Findings

SPD recommends SCE make the following adjustments to the information it provided in its 2026 RAMP as part of its Test Year 2029 General Rate Case application and future RAMP filings.

1. Regarding SCE's wildfire risk scope definition
   (finding 1)

SCE should quantify the wildfire risk associated with underground assets and assets outside SCE's HFRA and either incorporate the risk associated with those assets into its RAMP wildfire risk baseline or provide quantitative evidence supporting the exclusion of this risk from its wildfire risk scope. Separately, SCE should disclose the wildfire risk outside its HFRA that it already models but does not present in its 2026 RAMP. If SCE does not intend to mitigate that risk, it may report it as a single unit rather than as an individual RRU for each circuit.

2. Regarding risk scalars
   (findings 2 and 3)

SPD recommends that SCE provide the monetized risk values and resulting BCRs calculated on an unscaled basis for each circuit and RRU proposed for mitigation in its RAMP and associated GRC, that is, the values before SCE applies any risk scalars (e.g., the AFN, NRCI, and CFRA social vulnerability scalars) alongside the corresponding scaled values, so that the effect of the scalars on each BCR and on mitigation selection can be independently assessed.

3. Regarding CMI estimates
   (findings 4, 5, 6, and 7)

SPD recommends that SCE determine per-CMI reliability values differentiated by both customer class and HFRA status: SCE should determine separate values for (1) residential HFRA, (2) residential non-HFRA, (3) non-residential HFRA, and (4) non-residential non-HFRA. SCE should then apply each of the four values to the corresponding portion of every wildfire and PSPS-affected circuit, weighted by that circuit's residential and non-residential CMI within and outside the HFRA, and compute the monetized reliability benefit and resulting BCR on that basis. For consistency with wildfire scenario durations, SCE should derive each value using ICE inputs consistent with the outage duration SCE assumes for wildfire and PSPS scenarios (e.g., a SAIDI/SAIFI pair implying an average duration of approximately 480 minutes for wildfire scenarios) or demonstrate that values SCE derives from routine (non-MED) outages remain reasonable at those duration.

4. Regarding tranche assignment methodology
   (findings 8, 9, 10, and 11)

a. SCE should provide the segment-to-tranche crosswalk it states it incorporated, so that SPD can trace each proposed mitigation segment to its assigned tranche and to the tranche-level BCR supporting its selection.
b. SCE should provide its tranche assignment methodology, including the risk metric used, the quintile boundaries, and the population and circuits over which the quintiles were computed.
c. SCE should indicate whether it assigns tranche levels only to RRUs selected for proposed mitigation or to its full set of RRUs, circuit segments, or assets that are included in SCE's wildfire risk analysis, and if the former, explain how SCE performed tranche-based prioritization without tranche assignments for the unselected RRUs.
d. SCE should reconcile the reported RRU-level mitigation benefits with the tranche assignments. Specifically, SCE should (1) disaggregate each reported benefit into its wildfire and PSPS components, so the wildfire benefit can be compared against the wildfire LoRE/CoRE tranche; and (2) report pre-mitigation risk and mitigation benefit on a common segment basis and for the portion on which SCE is performing mitigation.
e. SCE should reconcile the reported LoRE and CoRE values with the tranche quintiles to which each RRU is assigned, or correct the assignments (for example, Ambercrest [C2] and Pampas [C1] have CoRE values well above those of RRUs SCE assigned to the highest consequence quintile [C5]).
f. In its next General Rate Case application and its next RAMP filing, SCE should (1) report tranche assignments for all RRUs, circuit segments, or assets that are included in SCE's wildfire risk analysis, not solely for the RRUs it has selected for mitigation and (2) provide a crosswalk linking each circuit segment to its RRU, to the risk tranche assigned to that RRU, and to the mitigation selected for that segment, together with the tranche-level BCRs supporting each selection.

5. Regarding disclosure of risk within each RRU
(finding 12)

SCE should disclose the full wildfire risk of the assets within each RRU, including secondary and service line risk, not only the risk of the portion it intends to mitigate. It should also include risk from underground assets (per the related recommendation above) in its risk assessment for each RRU. SCE should assess both pre- and post-mitigation residual risk, including unmitigated risk on those assets. SCE should add risk from secondary and service lines and underground assets as additional risk drivers within existing RRUs rather than defining these assets within their own RRUs.

6. Regarding incorporating in the BCR both benefits from and costs of secondary and service line hardening
(finding 13)

SCE should place the benefits and costs of secondary and service line hardening on the same basis in its benefit-cost analysis. Specifically, SCE should either (1) incorporate secondary and service line ignition risk

into the POI model and circuit rankings, so the risk reduction from that work is credited in the BCR numerator alongside its cost; or (2) disaggregate the secondary and service line component from the spend and per-mile cost metrics, so the numerator and denominator cover the same primary-only scope. SCE should also report the secondary and service line component of per-unit cost separately, so that per-mile and BCR figures are comparable across RRUs and tranches.

7. Regarding the equipment/facility failure driver frequency (finding 14)

SCE should state which annualized HFRA ignition frequency for the risk driver equipment/facility failure SCE used to calibrate the risk model in its 2026 RAMP, the frequency in the RAMP (20.3) or the frequency in SCE's response to Data Request SPD-SCE-2026RAMP-004, Question 2 (52.7). SCE should explain and reconcile the discrepancy between the two frequencies and, if the incorrect frequencies were used to calibrate the risk model, quantify the effect of using the corrected figures for the driver frequency and any BCRs that rely on them.

8. Regarding SCE's hardening and the no-build baseline (finding 15)

SCE should normalize its baseline for hardening. SCE should incorporate the expected ignition and risk reductions from hardening completed through 2028 into its 2029 no-build baseline, rather than calibrating that baseline using an unweighted average of 2019-2024 historical ignition counts that does not reflect the hardening already completed. SCE should make this adjustment using the same mitigation-effectiveness methodology it applies prospectively (per SCE's response to Data Request SPD-SCE-2026RAMP-004, Question 4) or, alternatively, demonstrate why an unweighted average across years with materially different levels of hardening is an appropriate calibration anchor for 2029 system conditions.

9. Regarding SCE's consequence conditions (Conditions 1–3) (finding 16)

SCE should reconcile the frequency of its Condition 3 category with the consequence it assigns, either by weighting the Condition 3 consequence by the historical rate at which qualifying ignitions actually resulted in structure loss, or by justifying the application of a structure-loss consequence profile to the full Condition 3 frequency (a LoRE of 6.2 events per year) when historically only approximately one ignition per year has destroyed structures. SCE should also disclose the number of ignitions with a cause other than electric facilities it used to derive the Condition 1–3 frequencies and explain their classification.

10. Regarding SCE's calibration of its POI model using its FIPA ignition dataset (finding 17)

SCE should address the issue of observation bias in its FIPA ignition dataset. Provide, for each year 2019-2024, the count of FIPA HFRA ignitions by driver, together with any available basis for distinguishing the portion of the year-over-year change attributable to improved detection and documentation from the portion attributable to physical change and demonstrate that the relative POI weights among drivers are not materially affected by the observation bias SCE has acknowledged.

11. Regarding WIM
(findings 18 and 19)
    a. SCE should reconcile the WIM scaling. SCE should justify the asymmetric construction of the WIM scaling: the scaling factors are floored at 1,[648] preventing any downscaling of FireSight 8 values while permitting upscaling toward the RMS 2.0-derived maxima. As constructed, scaled asset values are therefore greater than or equal to the original FireSight 8 values by design. SCE should demonstrate that this one-directional floor produces realistic consequence values rather than a systematic upward bias, and that the aggregate of the scaled values reconciles to the RMS 2.0 hexagon-level expected value SCE intends the scaling to respect.
    b. SCE should validate its WIM. SCE should provide justification that WIM is predictive of consequence. SCE's modeled loss is similar to that implied by past events despite substantial expenditure (e.g., covered conductor) to reduce risk; SPD views this as a sufficient basis to request additional validation of WIM. That validation should be systematic rather than a set of one-off cases, and should include:
        i. Reproduction of the data in SCE's Power Law White Paper (Part IV) using WIM, to validate that WIM is an improvement over the methodology SCE critiques in its white paper.
        ii. Demonstration that WIM is predictive of the location of risk (i.e., that high-impact fires occur near areas WIM predicts as high risk).
        iii. Validation that the risk (LoRE × CoRE) calculated using WIM is realistic in magnitude.
        iv. A systematic comparison of WIM outputs against historical fires—specifically, comparing values (e.g., structures destroyed) from the historical fires in SCE's Power Law White Paper Appendix C against WIM's predicted 25th, 50th, and 98th percentile values,[649] and overlaying the probabilistic fire hazard extents predicted by FireSight 8 and RMS 2.0 on the CAL FIRE fire perimeters for each fire SCE includes in Appendix C.[650]

12. Regarding SCE's vegetation management controls
(finding 20)

For SCE's vegetation management controls with BCRs below or barely exceeding 1, SCE should identify the portion of each program's proposed 2029-2032 scope that is required to meet applicable statutory, regulatory, or Commission-ordered minimums versus the discretionary scope above that floor, and justify

---

[648] SCE Power Law White Paper, p. 39, footnote 98.

[649] SCE Power Law White Paper, Appendix C "Catastrophic Wildfires in Southern California Edison Territory (2016-2025) that Meet OEIS Definition."

[650] CAL FIRE Historical Fire Perimeters (https://www.fire.ca.gov/what-we-do/fire-resource-assessment-program/fire-perimeters, accessed Aug. 26, 2026).

the discretionary, above-compliance scope on cost-effectiveness grounds or explain why it should be retained despite having BCRs that fall below or barely exceed its minimum BCR threshold.

13. Regarding SCE's Alternative Plan 2
    (finding 21)

For the 37 TUG miles added under Alternative Plan 2, including areas currently hardened with CC, SCE should provide the pre-mitigation LoRE and CoRE and the CC-adjusted residual risk on each segment that would be undergrounded under this plan, so that the reported per-mile risk reduction can be reconciled with the mitigation effectiveness assumptions in SCE's "Wildfire Mitigation Effectiveness" work paper (where, for example, in the case of ignition from vegetation contact, SCE estimates that CC is 71 percent effective and TUG is 100 percent effective at reducing ignition risk).

14. Regarding SCE's formula for calculating net O&M for TUG
    (finding 22)

SCE should correct its net O&M formula for TUG so that the new TUG operating cost (N) is counted once rather than twice (the 2N - B structure) and recalculate its BCR for TUG accordingly.

15. Regarding SCE's use of inconsistent baselines to calculate O&M cost for CC and TUG
    (finding 23)

SCE should provide the derivation of its estimated $62K per mile per year existing bare wire overhead infrastructure O&M cost from its historical HFRA overhead system O&M expenditures, including the underlying expenditure data and the per-mile calibration, so that SPD can independently verify the estimate.

16. Regarding SCE's inconsistent use of baseline O&M in calculating the BCRs of CC and TUG
    (findings 22, 23, 24, 25, and 26)

SCE should, where it didn't do so initially, recalculate the BCR for all wildfire mitigations so that:

a. The O&M cost term reflects only the incremental O&M introduced by the new mitigation, with the existing bare wire baseline O&M cost or other no-build baseline O&M cost entering the calculation only through the O&M savings term (to the extent the mitigation eliminates all or part of that baseline activity), consistent with the directive of the RDF Phase 4 Decision to include only incremental expenses made necessary by the capital investment.
b. The calculation measures the risk reduction benefit of the mitigation and the mitigation's O&M costs and O&M savings against) the same no-build baseline.
c. The calculation incorporates the baseline O&M cost on the same no-build basis across all mitigations, including CC and TUG.
d. All components of the BCR (i.e., risk reduction, O&M savings, O&M costs, and capital costs) are incremental to, and measured against, a single, well-defined no-build baseline that incorporates the benefits of existing programs and completed risk reduction projects.

17. Regarding discrepancies in SCE's estimated mitigation benefits (finding 27)

SCE should reconcile the sum of RRU-level mitigation benefits reported in the "Wildfire Benefit Cost Ratio Calculations" workpaper (estimated by SPD at about $17.26 billion) with the system-level risk reduction implied by the risk score summary tables in its RAMP application (estimated by SPD at about $4.30 billion). SCE should state the annualization convention it intends for the risk reduction its presents in its RAMP risk summary tables, identify the source of the approximately four-fold difference, and correct any erroneous figures. Because SCE calculates BCRs for individual RRUs using the RRU-level benefits, SCE should state whether and how any correction to estimated benefits affects those BCRs.

18. Regarding SCE's estimated mitigation costs discrepancies (finding 28)

SCE should reconcile the total mitigation costs it presents in its "Wildfire Benefit Cost Ratio Calculations" work paper with the total mitigation costs it presents in its RAMP application for CC and TUG and should apply the O&M component of the BCR denominator on a consistent basis for both mitigations, so that the CC and TUG BCRs are comparable.

19. Regarding SCE's BCR calculation method for CC with REFCL (findings 29, 30, and 31)

SCE should estimate REFCL's benefits and costs separately from CC so that it can evaluate REFCL's stand-alone BCR independently of the BCR for the CC investment. Specifically, SCE should: (1) disaggregate the per-mile cost rate it blends into its REFCL and CC BCR calculation; (2) report the risk reduction and mitigation benefit attributable to REFCL alone, excluding any CC risk reduction already realized or counted in a prior CC BCR; (3) either include the wildfire, safety, and reliability benefits REFCL brings to reducing risk for areas outside the HFRA or exclude the corresponding cost for REFCL outside the HFRA, so that costs and benefits are on the same scope; and (4) explain why, for 20 RRUs where both CC and CC with REFCL are proposed, SCE estimates a lower mitigation benefit (WACC) for CC with REFCL than for CC alone, despite a larger modeled risk reduction, and reconcile the implied present-value factor for CC with REFCL installations, which is as low as 2.38, with the 11.43-14.23 implied present-value factor range SCE applies to the proposed CC-only investments.

20. Regarding SCE's customer-facing PSPS programs (finding 32)

For all customer-facing PSPS programs, SCE should delineate the mandated versus discretionary scope and spend and identify the governing authority for the mandated portion.

21. Regarding SCE's lack of modeled ignition pathway for idle and out-of-service facilities (finding 33)

SCE should state whether its wildfire risk model assigns any probability of ignition to idle or out-of-service facilities in its HFRA. If it does, SCE should identify the driver classification and calibrating data; if not, it should quantify the omitted risk or justify the exclusion.

22. Regarding SCE's operational treatment of idle-facility grounding risk (finding 34)

SCE should reconcile its operational treatment of idle-facility grounding risk with the absence of this risk from its 2026 RAMP wildfire risk model and describe whether the model will incorporate this ignition pathway in future filings.

23. Regarding SCE's lack of disaggregation by asset class in reporting wildfire risk (finding 35)

SCE should report total wildfire risk disaggregated by asset class (distribution, sub-transmission, and transmission) at the LoRE, CoRE, and risk-score levels.

2. Overhead Equipment Failure Risk

Risk Description

The Southern California Edison Company (SCE) defines overhead equipment failure (OEF) risk as distribution overhead equipment failures that can cause significant public and employee safety incidents, property and environmental damage, and compromise system reliability by limiting SCE's ability to deliver energy safely and consistently.[651]

In its 2026 Risk Assessment and Mitigation Phase (RAMP) risk selection process, after SCE scored a set of enterprise risks found in its Enterprise Risk Register, SCE found that OEF is its second-highest hazard-based enterprise risk, as measured by the combined safety, reliability, and financial risk score, with the first-highest risk being wildfire and Public Safety Power Shutoff (PSPS).[652] Although OEF is often associated with wildfire risks—either because the OEF contributed to the fire, or because a fire might damage equipment—SCE is distinguishing OEF risk from wildfire risk, addressing wildfire risk in a separate chapter. OEF risk is limited in SCE's RAMP application to "non-wildfire public safety and reliability risks."[653]

OEF can result from degradation caused by aging and exposure to environmental hazards such as adverse weather and incidental contact with vegetation, wildlife, and third-party objects. SCE notes that "the cumulative impacts of these stressors make failures almost unavoidable."[654] OEF can cause outages that jeopardize public and worker safety, disrupt critical services, and undermine community resilience.

Because both safety incidents and reliability disruptions often stem from the same underlying asset failures, SCE addresses these risks through an integrated risk management approach focused on prevention, timely detection, response, and proactive asset replacement.

Table 2-1 provides SCE's definition of OEF risk along with the risks considered in- and out-of-scope for this RAMP chapter, indicating that SCE excludes wildfire risk from OEF risk.[655]

---

[651] SCE 2026 RAMP, Chapter 5 "Overhead Equipment Failure," Table II-3 "Overhead Equipment Failure Chapter Scope," p. 7.

[652] SCE's Pre-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop Presentation, Dec. 18, 2025, slide 14 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-pre-filing-ramp-workshop-slides_dec-2025.pdf, accessed July 10, 2026).

[653] SCE 2026 RAMP, Ch. 5, p. 1.

[654] SCE 2026 RAMP, Ch. 5, p. 2.

[655] SCE 2026 RAMP, Ch. 5, Table II-3 "Overhead Equipment Failure Chapter Scope," p. 7.

Table 2-1. OEF Risk Definition and Scope[656]

Item	OEF Risk Element Description
Risk Name	Overhead Equipment Failure.
Definition	Failures of overhead distribution equipment that result in public or employee safety incidents, property or environmental damage, and reduced system reliability.
In Scope	Failures of primary distribution overhead equipment, including: ▪ Contact from objects (e.g., vegetation, animals, balloons). ▪ Equipment facility failures involving overhead equipment such as conductors, transformers, fuses, insulators, lightning arresters, and regulators.
Out of Scope	The following risks are not addressed in SCE's RAMP Chapter 5 "Overhead Equipment Failure," but are addressed in other RAMP chapters: ▪ Employee or contractor contact with energized equipment. ▪ Theft-related contact with energized equipment. ▪ Vehicle contact with energized equipment. ▪ Contact with substation or transmission equipment or conductor. ▪ Wildfire ignition risks (addressed separately in SCE's RAMP Chapter 4 "Wildfire and PSPS").

Key Changes from SCE's 2022 RAMP to 2026 RAMP

Table 2-2 summarizes the changes in SCE's approach to OEF since its 2022 RAMP.

Table 2-2. Changes from SCE's 2022 RAMP to 2026 RAMP[657]

2022 RAMP	2026 RAMP	What Changed
Contact with Energized Equipment (CEE) posed the primary risks.	Introduces Overhead Equipment Failure (OEF) and Underground Equipment Failure as distinct RAMP risks.	Shift from an outcome-focused framework to an asset-based framework. SCE explains that it did not perform a one-to-one comparative risk-reduction analysis between the two frameworks (CEE and OEF), as they reflect fundamentally different approaches to risk definition and evaluation. Rather, SCE relied on a risk-modeling approach and a portfolio-level risk-

[656] SCE 2026 RAMP, Ch. 5, Table II-3 "Overhead Equipment Failure Chapter Scope," p. 7.

[657] SCE 2026 RAMP, Ch. 5, Table II-2 "Evolution of Overhead Risk Treatment," p. 6.

2022 RAMP	2026 RAMP	What Changed
		reduction analysis.[658]
Risks framed around outcomes such as electrical contact, wire-down incidents, or failures.	Risks are framed around the type of infrastructure asset (overhead vs. underground).	SCE models its risk by asset class to enable more targeted mitigations.
Overhead-related incidents included under "Contact with Energized Equipment."	Overhead system risks are grouped under OEF.	Broader and more proactive infrastructure-based risk categorization.
Third-party incidents (e.g., dig-ins, contact with energized lines by contractors/tree trimmers) included within Contact with Energized Equipment.	Third-party-driven risks are removed from OEF and moved into a new Public Safety Risk chapter.	Separates utility asset failures from externally caused public safety events. Third-party risks have been moved to the Public Safety Risk chapter because they aligned better with external causal drivers and targeted mitigation strategies.[659]
Risk structure emphasized consequences such as shock/contact events.	Risk structure emphasizes the condition and management of assets themselves.	Supports more granular mitigation planning depending on whether equipment is overhead or underground.
Contact with energized equipment combined multiple risk sources into one category.	Risks are disaggregated into overhead failure, underground failure, and third-party/public safety risks.	Improves clarity, traceability, and alignment of mitigation.

[658] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 13(a).

[659] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 14(a).

Observations and Findings

Because safety and reliability impacts are closely interconnected, addressing them separately may leave significant residual risk unmitigated. Safety Policy Division (SPD) finds that a comprehensive approach that considers both safety and reliability outcomes is necessary to effectively manage OEF risk and support the continued safe and reliable operation of the distribution system.

SPD observes that SCE has adopted a comprehensive approach to consequence evaluation. The approach acknowledges that equipment failures may initially affect system reliability but can escalate into safety events under certain conditions while increasing financial impacts. This framework supports proactive inspection, maintenance, and replacement strategies to reduce overall risk.

Observations About Key Changes from SCE's 2022 RAMP to 2026 RAMP

The most significant change SCE introduces in its 2026 RAMP is the transition from an outcome-based approach to an asset-based approach, allowing more asset-specific assessments of risk and mitigation effectiveness.[660] SCE asserts that the outcome-based approach "provided SCE important insights into high-consequence events" but did not fully capture the systemic nature of overhead asset risk or support comprehensive assessment or prioritization of risk mitigations.[661] SPD observes that this change to an asset-based risk model likely enables SCE to:

- Tailor mitigation by asset type.
- Isolate third-party and public interaction risks.
- Improve risk modeling precision.
- Elevate public safety risk into a dedicated enterprise risk category.

[660] SCE 2026 RAMP, Ch. 5, pp.4-6.

[661] SCE 2026 RAMP, Ch. 5, p.4.

Risk Bow Tie

SCE presents the following risk bow tie for OEF risk:

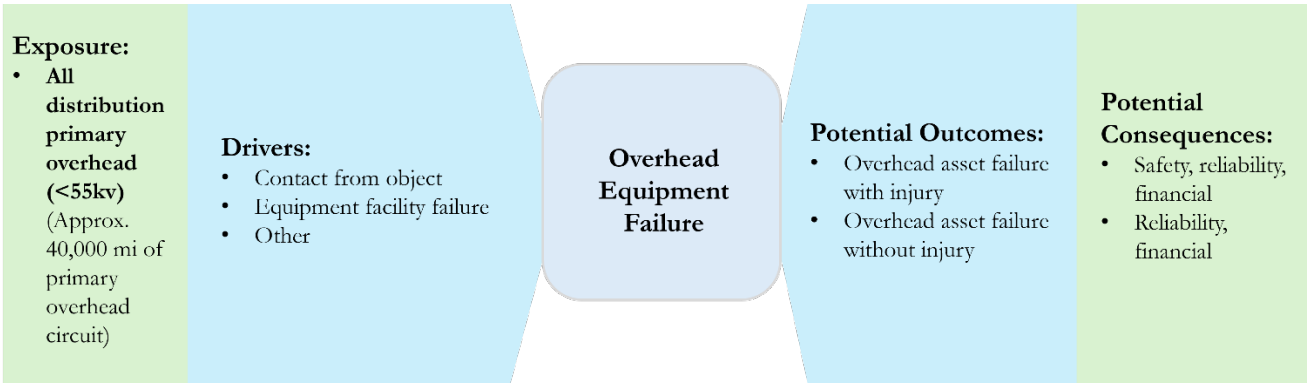


Figure 2-1. SPD Adaptation of SCE Overhead Equipment Failure Risk Bow Tie[662, 663]

Observations and Findings

SCE identified two main drivers of OEF risk: contact from object (CFO) and equipment facility failure (EFF). Together, these account for most safety, reliability, and financial risk events across the overhead distribution system. These drivers either increase the likelihood of overhead asset failures or exacerbate their consequences when failures occur. Effective risk mitigation, therefore, requires addressing both external contact events and equipment-related failures.

SCE's historical event data indicate that EFF is the dominant OEF risk driver, accounting for approximately 75 percent of all events, while CFO accounts for the remaining 25 percent.[664] These results demonstrate that OEF risk is concentrated among a limited set of recurring drivers, suggesting that targeted mitigation strategies can address most of the system risk.

In a data request response, SCE stated that it calculated annualized driver frequencies for overhead equipment failure using filtered 2020–2024 outage data for in-scope events.[665] It also stated that it classified

[662] SCE 2026 RAMP Ch. 5, Figure II-1 "Risk Bowtie for OH Equipment Failure," p. 8.

[663] SCE's original bow tie figure includes the number 5,925 with the description of the triggering event: the number is not labeled in SCE's bow tie figure; it likely refers to the five-year average of risk events, including all primary risk drivers, for the period 2020-2024, which is 5,925, as seen in Ch. 5, Table II-4 "Annualized Driver Frequency," p. 8.

[664] SCE 2026 RAMP Ch. 5, Table II-4 "Annualized Driver Frequency," p. 8.

[665] SCE's response to Data Request SPD-SCE-2026RAMP-005, Question 38(a).

the events by root cause into CFO, EFF, and other driver categories, aggregated them annually, and averaged the results over the five-year period to estimate the annual triggering risk frequency of 5,925.[666, 667]

Exposure

SCE defines its overhead equipment failure exposure as all its distribution primary overhead (below 55 kV), which it approximates at 40,000 primary overhead circuit miles.[668] SCE has identified the full population of applicable overhead distribution circuits as within the scope of OEF risk exposure.

Observations and Findings

SPD has no observations or findings on the exposure.

Tranches

SCE applied a quintile tranching methodology for OEF risk, dividing its overhead electric facilities into five risk-based tranches (quintiles), ranging from the lowest to the highest-risk assets. In a data request response, SCE stated that it uses a consistent quintile-based methodology across asset classes and risk types to establish likelihood and consequence thresholds.[669] Under this approach, SCE derives likelihood and consequence thresholds from the relative distribution of modeled risk values across assets, yielding risk-specific breakpoints driven by data, rather than by thresholds based on fixed values or equal numeric intervals.[670]

Observations and Findings

SCE's quintile tranching methodology is consistent with California Public Utilities Commission (Commission or CPUC) guidance in the RDF Phase 3 Decision.[671] SCE's framework groups assets according to their likelihood of failure and potential consequences, providing a structured, transparent basis for risk assessment across the system. SCE's approach enables it to prioritize mitigation activities and investments on higher-risk assets, where safety and reliability benefits are expected to be greatest, while lower-risk tranches receive proportionally less focus. SCE's approach also supports the evaluation of

---

[666] SCE's response to Data Request SPD-SCE-2026RAMP-005, Question 38(a).

[667] SCE 2026 RAMP Ch. 5, Table II-4 "Annualized Driver Frequency," p. 8.

[668] SCE 2026 RAMP Ch. 5, Figure II-1 "Risk Bowtie for OH Equipment Failure," p. 8.

[669] SCE's response to Data Request SPD-SCE-2026RAMP-005, Question 23(a).

[670] SCE 2026 RAMP Ch. 5, Figure II-2 "Overhead Equipment Failures 2029 Unmitigated 5x5 Tranching," p. 13.

[671] D.24-05-064, Appendix A, Row 14, pp. A-13-A-14.

mitigation cost-effectiveness, helping ensure that resources are allocated based on risk and expected value rather than applied uniformly across all assets.

Risk Reporting Units (RRUs)

SCE defines polygon-based RRUs for OEF risk. SCE's polygon-based RRUs group electrically connected portions of a distribution circuit into manageable sections that reflect how assets fail, outages occur, and mitigation work is planned and executed.

Observations and Findings

SCE demonstrates its polygon RRU approach with an illustrative figure showing the RRUs for the Finch Distribution Circuit.[672] In response to a data request from SPD, SCE explained that it did not provide the underlying GIS and tracing data for that figure because it was an illustrative example.[673] In its response, SCE provided data for the Allison Circuit as a representative example demonstrating how the polygon RRU methodology is applied to an actual distribution circuit.[674] In that example, SCE aggregates more than 250 individual primary overhead distribution circuit segments into six polygon RRUs using the methodology described in SCE's Polygon Definition and Tracing Methodology work paper.[675] SCE also provided the associated GIS geometry, segment-to-polygon mapping, and polygon risk values to illustrate how circuit segments are aggregated and how the methodology is applied in risk assessment and mitigation planning. According to SCE, this example demonstrates the rationale for polygon aggregation, as evaluating individual circuit segments would result in fragmented, operationally inefficient mitigation planning.

The use of polygon RRUs appears to provide a reasonable framework for targeting localized overhead equipment risks and for prioritizing mitigation activities more effectively than evaluating risk at either the entire circuit or the individual circuit segment level. However, because polygon RRUs are intended primarily as planning and prioritization units, and their boundaries may be adjusted during project execution, the methodology would benefit from greater transparency regarding the underlying geographic information system (GIS) data, polygon delineation criteria, and circuit-tracing information to enable independent verification of the risk assessments and the prioritization of mitigation measures.

Figure 2-2 is SCE's figure illustrating how a single distribution circuit is divided into polygon-based RRUs (in which SCE notes "color shading in [this figure] is for illustrative purposes only and does not represent

---

[672] SCE 2026 RAMP Ch. 5, Figure II-3 "Finch Distribution Circuit Segmented by Polygons," p. 15.

[673] SCE 2026 RAMP Ch. 5 Overhead Equipment Failure, Figure II-3 "Finch Distribution Circuit Segmented by Polygons," p. 15.

[674] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 40.

[675] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 40 (spreadsheet SPD-SCE-2026RAMP-005_Q40_Supplemental); SCE 2026 RAMP Ch. 5 work paper "Polygon Definition and Tracing Methodology."

prioritization, condition, or risk; it is intended solely to distinguish polygons along the Finch circuit and demonstrate typical polygon boundaries"[676]).

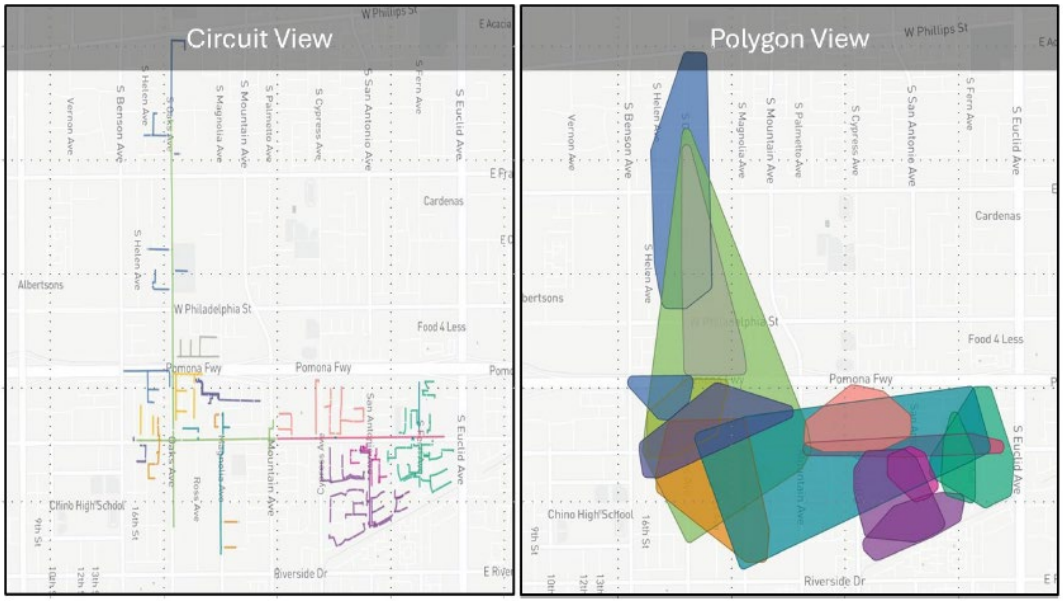


Figure 2-2. SCE's Illustration of the Finch Distribution Circuit Segmented by Polygons.[677]

Risk Drivers

In its risk bow tie, SCE presents two potential leading indicators for this risk, or drivers:

- **Contact from object (CFO):** This includes external contacts such as vegetation, animals, weather, and foreign objects.
- **Equipment facility failure (EFF):** This includes failures resulting from aging, degradation, weather, and operational stress on utility-owned assets.

SCE's analysis incorporates both event frequency and customer-impact metrics, providing a structured basis for prioritizing risk-mitigation efforts across the overhead distribution system.[678] SCE models CFO and EFF risk events separately in the calculation of the likelihood of a risk event (LoRE) because they involve different failure mechanisms and require distinct datasets, drivers, and failure-frequency calculations.[679]

---

[676] SCE 2026 RAMP Ch. 5, p. 15, footnote 14.

[677] SCE 2026 RAMP Ch. 5, Figure II-3 "Finch Distribution Circuit Segmented by Polygons," p. 15.

[678] SCE 2026 RAMP Ch. 5, pp. 8-9.

[679] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 18(a).

As noted above, EFF is the predominant contributor to OEFs, occurring at nearly three times the frequency of CFO events over 2020-2024.[680] High-frequency and high-impact failure modes, particularly conductor and transformer failures, along with weather-related and vegetation-related events, appear to be the most significant drivers of system risk, supporting the need for targeted asset replacement, equipment hardening, inspection programs, and vegetation management initiatives.[681]

Observations and Findings

SPD has no observations or findings on these risk drivers.

Consequences

OEFs can result in a range of consequences that extend beyond the initial failure. Depending on the circumstances, an OEF may directly create a safety hazard or a reliability issue that later escalates into a safety event. Such events can also lead to significant financial impacts due to the need for emergency response, restoration activities, and unplanned repairs. SCE explained in a data request response that reliability and safety consequences are evaluated using separate triggering thresholds, with consequence assessments based on modeled outcomes that account for safety, reliability, and financial impacts.[682] In its response, SCE also stated that its 2026 RAMP Environmental and Social Justice (ESJ) Pilot evaluates how OEF risks, mitigations, and resulting risk-reduction benefits may differ across Disadvantaged and Vulnerable Communities (DVCs) and other communities in its service territory.[683]

Observations and Findings

SPD recognizes that OEFs can follow multiple outcome pathways, with consequences spanning safety, reliability, and financial impacts. SCE's approach to mitigating OEF risk is progressive and interconnected. For example, SCE may initially classify a failure as a reliability event, but it may escalate it into a safety event under certain conditions. SCE evaluates these impacts using fatalities and serious injuries, customer service interruptions measured by customer minutes interrupted (CMI), and costs associated with emergency response and unplanned repair services.

While SCE may initially classify OEFs as reliability incidents, it can later escalate them to safety-related events, depending on factors such as location, public exposure, and restoration conditions.

---

[680] SCE 2026 RAMP Ch. 5, Table II-4 "Annualized Driver Frequency," p. 8.

[681] SCE 2026 RAMP Ch. 5 Overhead Equipment Failure, Table II-5 "Consolidated Summary of Overhead Equipment Failure Drivers," p. 10.

[682] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 19.

[683] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 22.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[684]

Controls

OEF controls encompass the range of ongoing programs, maintenance activities, inspections, and mitigation measures designed to reduce both the frequency and impact of OEF events across the distribution system.

SCE's controls, listed in Table III-6,[685] comprises six key programs focused on improving the condition, reliability, and resilience of the overhead distribution system. These include:

- Overhead Conductor Program (C1-OCP)
- Worst Performing Circuit Program (C2-WPC)
- Overhead Switch Program (C3-OHS)
- Distribution Deteriorated Pole Program (C4-DDP)
- Distribution Preventative and Breakdown Maintenance (C5-DPBM)
- Distribution Routine Vegetation Management (C6-DRVM)

In SCE's 2022 RAMP, its Overhead Conductor Program (C1-OCP) was the utility's only control for OEF risk. The five other controls in SCE's 2026 RAMP are new. The OCP program proactively replaces overhead conductor degraded by age and environmental exposure. In this RAMP, the primary mitigation approach in the OCP program is to replace bare conductor with covered conductor to improve safety and reliability.[686]

Collectively, the OCP program and other controls aim to improve safety and reliability through critical infrastructure replacement, equipment maintenance, and vegetation management. SCE targets improvements to underperforming circuits to reduce the likelihood and consequences of OEFs.

All six control programs are included in the 2026–2028 and 2029–2032 planning periods and are incorporated into the utility's proposed plan as well as both alternative plans.

Mitigations

In the 2026 RAMP, SCE did not include any new mitigations in its proposed plan. However, the utility introduced two mitigation strategies for OEF risk in its alternative plans: Distribution Reliability

---

[684] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[685] SCE 2026 RAMP Ch. 5, Table III-6 "List of Controls Impacting Overhead Equipment Failure," p. 17.

[686] SCE 2026 RAMP, Chapter 5 Overhead Equipment Failure, p. 18.

Automation (DRA), included in Alternative Plan 1, and Non-HFRA Infrared (IR) Scanning, included in Alternative Plan 2. These mitigations are aimed at improving system performance through automation technologies and enhanced asset condition monitoring.

The proposed mitigations primarily focus on reducing the impact of OEFs on reliability. In particular, the DRA strategy is designed to improve fault isolation and service restoration through automated switching and alternate circuit feeds, thereby reducing outage duration and limiting customer interruptions.

Observations and Findings

SPD has no observations or findings on the controls and mitigations described in SCE's OEF chapter.

Alternatives Analysis

SCE presents two alternatives to its proposed plan. Under Alternative Plan 1, Distribution Reliability Automation (DRA) focuses on reducing the consequences of OEF events by improving fault isolation and service restoration, thereby minimizing outage duration and customer impacts. Under Alternative Plan 2, IR scanning targets equipment condition-related risk drivers by identifying thermal anomalies that may not be detectable through routine visual inspections, helping prevent failures and reduce the likelihood of outages and emergency repairs. Together, these alternatives present distinct strategies for managing OEF risk—one focused on reducing the impact of failures and the other on preventing them.

In a data request response, SCE stated that DRA and IR scanning are primarily detection- and response-based measures that generally reduce consequence duration and support targeted interventions, rather than directly reducing the likelihood of failure or eliminating underlying safety hazards comparable to the proposed plan.[687] SCE also stated in a data request response that greater reliance on DRA and IR scanning would result in higher residual risk than its proposed plan of targeted hardening for the highest-risk overhead assets.[688]

Observations and Findings

SPD observes that SCE's two alternative mitigation plans emphasize different aspects of risk management for OEFs. These alternatives are not intended to serve as direct substitutes for the proposed overhead conductor program, nor do they represent an apples-to-apples comparison, as they address different risk mechanisms and objectives.

SPD finds that neither alternative provides the same level of risk reduction as SCE's proposed strategy that focuses on proactive conductor replacement. While Alternative Plan 1 improves outage restoration and

[687] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 33.

[688] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 31.

customer reliability outcomes following a failure, it does not address the underlying causes of OEFs and would require a substantially higher investment, approximately $242 million over the 2029-2032 period.[689]

Conversely, Alternative Plan 2 represents a relatively low-cost condition assessment approach, approximately $1 million over the same period, that primarily supports issue identification and maintenance prioritization rather than directly reducing the likelihood of failure or safety exposure.[690]

Based on these differences in purpose, effectiveness, and cost, SPD agrees that a balanced approach combining proactive asset replacement with supplemental mitigation measures provides a more effective way to manage both the causes and consequences of OEF risk.

BCR Calculations

SCE calculates BCR values for six controls and two mitigations for OEF risk. SCE presents all BCRs, as required, under three discount rate scenarios: a weighted-average cost of capital (WACC) rate, a societal rate, and a hybrid rate.

Table 2-3 presents SCE's projected BCRs for the six controls in SCE's proposed plan for mitigating OEF risk.

Table 2-3. OEF's Proposed Estimated Program Costs and BCRs (2029-2032) ($000s)[691]

Control ID	Control Name	O&M Costs	Capital Costs	Total Costs	BCR (WACC)	BCR (Societal)	BCR (Hybrid)
C1	Overhead Conductor Program (OCP)		$1,620,045	$1,620,045	3.99	12.16	5.35
C2	Worst Performing Circuit (WPC)		$45,898	$45,898	0.53	1.04	0.66
C3	Overhead Switch (OHS) Program		$31,469	$31,469	1.28	2.56	1.61
C4	Distribution Deteriorated Pole (DDP) Program	$49,164	$605,210	$654,374	0.13	0.17	0.15
C5	Distribution Preventative and	$89,926	$1,418,525	$1,508,451	0.65	1.28	0.81

[689] SCE 2026 RAMP Ch. 5, Table IV-14 "Annual Notional DRA Program Scope and Spend," p. 34.

[690] SCE 2026 RAMP Ch. 5, Table IV-15 "Annual Notional Non-HFRA IR Scanning Units and Spend," p. 35.

[691] SCE 2026 RAMP Ch. 5, Table VI-17 "Proposed Plan Programmatic Estimated Spend and Benefit-Cost Ratios," p. 37.

Control ID	Control Name	O&M Costs	Capital Costs	Total Costs	BCR (WACC)	BCR (Societal)	BCR (Hybrid)
	Breakdown Maintenance (DPBM)						
C6	Distribution Routine Vegetation Management (DRVM)	$1,220,620		$1,220,620	0.01	0.01	0.02
	Total	**$1,359,711**	**$3,721,147**	**$5,080,858**	**1.50**	**4.31**	**1.98**

Although the overall portfolio achieves a BCR greater than 1.0, and the highest BCR belongs to the control that costs the most, the Overhead Conductor Program (C1), the next two costliest controls, Distribution Preventative and Breakdown Maintenance (C5) and Distribution Routine Vegetation Management (C6) have relatively low BCRs. Nearly two-thirds of the total $5.08 billion investment (i.e., 73 percent capital costs and 27 percent O&M costs) is allocated to programs with BCRs below 1.0 under two of the three BCR rate scenarios (Controls C4–C6, with only C5 having one BCR above 1.0, under the societal rate), indicating that much of SCE's investment is driven by reliability, safety, asset health, or regulatory obligations rather than cost-effectiveness. The overall portfolio's 1.98 BCR is driven above 1.0 mostly by the relatively high BCR of the Overhead Conductor Program.

Table 2-4 summarizes the total costs and BCRs for all three plans.

Table 2-4. BCR Calculations for OEF's Proposed and Alternative Plans (2029-2032) ($000s)[692]

Plan Name	O&M Costs	Capital Costs	Total Costs	BCR (WACC)	BCR (Societal)	BCR (Hybrid)
Proposed Plan	$1,359,711	$3,721,147	$5,080,858	1.50	4.31	1.98
Alternative 1	$1,359,711	$2,697,733	$4,057,444	1.10	2.75	1.42
Alternative 2	$1,360,775	$2,455,689	$3,816,464	0.94	2.51	1.22

SCE compared the BCRs of its proposed plan against its two alternatives using the three discount rates. Under all three BCR rates, the proposed plan yielded the highest portfolio-level BCRs; Alternative Plan 1

[692] SCE 2026 RAMP Ch. 5, Table VII-21 "Overhead Equipment Failure Proposed Plan and Alternative Plans Summary of Control Program Estimated Costs and Benefit-Cost Ratios for 2029-2032," p. 40.

(reduced OCP with DRA) and Alternative Plan 2 (reduced OCP with IR Scanning) both come out as less cost-effective.

The societal BCRs, discounted at 2 percent, are substantially higher than the WACC BCRs, which in 2026 are discounted at 7.59 percent.[693] The lower societal discount rate places greater value on future benefits, particularly for long-lived infrastructure investments. The hybrid BCR falls between the two and reflects a blended treatment of safety, reliability, and financial benefits.

Observations and Findings

SCE may want to reassess the scope or assumptions of its low-BCR investments to improve the overall cost-effectiveness of its proposed plan.

The comparison of the BCRs of the proposed and alternative plans indicates that the proposed plan not only delivers the greatest risk reduction but also provides the strongest overall cost-effectiveness across all evaluation methods. While the alternative plans cost less, DRA and IR scanning primarily address consequences or improve asset condition awareness but do not reduce the likelihood of failure.

The proposed plan's BCR is driven up by the Overhead Conductor Program (C1). Its cost-effectiveness is due in part to the fact that conductor replacement generates risk reduction benefits over many years. SCE's proposed plan, which relies heavily on this program, outperforms the alternatives that substitute DRA or IR scanning for conductor replacement.

Summary of Findings

SPD finds that:

1. SCE's introduction of an asset-based approach to assessing risk allows a more asset-specific assessment of risk and mitigation effectiveness.
2. SCE's continued focus on targeting mitigations to address EFF and CFO, the primary drivers of OEF risk, offers the greatest potential to improve safety and reliability outcomes.
3. SCE's focus on proactive asset management and preventive maintenance can address OEF reliability events before they escalate into safety incidents.
4. SCE's polygon-based RRUs reasonably support localized risk prioritization and mitigation planning.
5. SCE's proposed OEF risk mitigation plan outperforms the less-costly alternative plans in terms of cost-effectiveness and addresses critical infrastructure replacement, equipment maintenance, and vegetation management, and targets improvements to underperforming circuits to reduce the likelihood and consequences of OEFs.

[693] Application of Southern California Edison Company (U 338-E) Regarding 2026 Risk Assessment Mitigation Phase (SCE 2026 RAMP), Chapter 2 "Risk Model and BCR Methodology," p. 26.

Recommendations to Address Findings

SPD recommends that SCE:

1. Continue refining its asset-based risk model to improve risk prioritization, target mitigation, and investment decision-making to achieve overall safety and reliability outcomes.
2. Continue to prioritize mitigation investments addressing EFF and CFO.
3. Provide the underlying data and methodology for its polygon-based RRUS to improve transparency, facilitate independent validation, and strengthen the credibility of SCE's risk-based decision-making.
4. Maintain a balanced OEF risk-management strategy that combines proactive asset replacement with complementary measures, such as automation, asset monitoring, and preventive maintenance, to address both the causes and consequences of equipment failures.
5. Consider reassessing the scope or assumptions of its low-BCR investments to improve the overall cost-effectiveness of its proposed plan.

3. Underground Equipment Failure Risk

Risk Description

The Southern California Edison Company (SCE) defines underground equipment failure (UEF) risk as "the potential safety and reliability impacts associated with the failure of underground electric distribution system assets, including transformers, cables, capacitor banks, splices, switches, vaults, fuses, and manholes."[694] SCE states that while the most common consequence of a UEF is a service outage, in rare cases a UEF can result in fire and even violent explosions that pose a direct safety risk to the public.[695] In defining its scope for this risk chapter, SCE assessed the risk only for equipment on the primary side of the distribution system (higher-voltage lines between the utility and the transformer) and did not include the secondary side of the distribution system (lower-voltage lines between the transformer and the customer).[696] SCE also does not address secondary consequences related to reliability impacts from UEFs. Furthermore, SCE excludes risk from contact with energized equipment by employees, contractors, or members of the public (including those involved in the theft of SCE equipment).[697] SCE discusses the risk from contact with energized equipment by these parties in its RAMP risk chapters covering employee safety, contractor safety, and physical security, respectively.[698]

SCE changed its UEF risk analysis since its 2022 Risk Assessment and Mitigation Phase (RAMP) application by shifting focus from low-likelihood, high-consequence tail-risk events to addressing the full range of underground equipment failures.[699] SCE notes that this shift also emphasizes proactive prevention of equipment failure through replacement where warranted, rather than limiting consequences by reinforcement and remediation. [700]

Observations and Findings

While safety is crucial and UEF poses safety risks from explosion events, Safety Policy Division (SPD) observes that UEF events involving injury are rare, with the last UEF event in SCE's service territory that resulted in serious injuries being an explosion in Huntington Beach in 2019, which resulted in injuries to two

---

[694] SCE 2026 RAMP, Chapter 6, "Underground Equipment Failure," p. 5.

[695] SCE 2026 RAMP, Ch. 6, p. 5.

[696] SCE 2026 RAMP, Ch. 6, Table II-3 "Underground Equipment Failure Chapter Scope," p. 8.

[697] SCE 2026 RAMP, Ch. 6, Table II-3 "Underground Equipment Failure Chapter Scope," p. 8.

[698] SCE 2026 RAMP, Ch. 6, p. 8, footnote 7.

[699] SCE 2026 RAMP, Ch. 6, pp. 6-7.

[700] SCE 2026 RAMP, Ch. 6, p. 7.

firefighters and three civilians.[701, 702] Furthermore, considering the three attributes that SCE must evaluate as part of the Risk-Based Decision-Making Framework (RDF) requirements, safety, reliability, and financial,[703,704] SCE calculates that, considering pre-mitigation risk, safety risk accounts for less than 0.6 percent of the total estimated consequence of a risk event (CoRE) value, with financial risk accounting for about 4 percent of total CoRE, and reliability risk accounting for about 95.4 percent of total CoRE.[705] Given the distribution of estimated consequences across these attributes, SPD understands SCE's change from focusing on tail-risk events to focusing on "proactive risk prioritization" across the system of underground assets: this approach may better allow for the prioritization of reliability-related mitigations.[706]

SPD also observes that SCE should consider including in its scope for UEF risk the secondary impacts of outages with safety and reliability ramifications.

Risk Bow Tie

SCE presents the following risk bow tie for underground equipment failure risk:

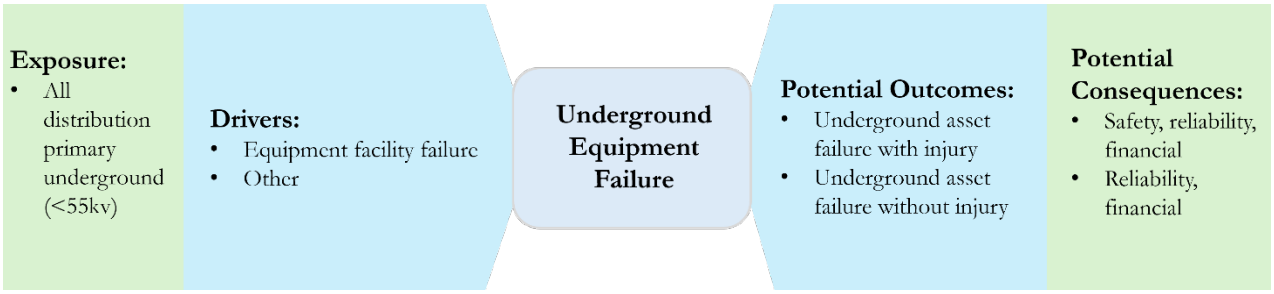


Figure 3-1. SPD Adaptation of SCE Underground Equipment Failure Risk Bow Tie[707]

---

[701] SCE 2026 RAMP, Ch. 6, p. 6.

[702] Los Angeles Times After blasts injure five at Oktoberfest in Huntington Beach, many ask: What caused them? (Oct. 6, 2019) (https://web.archive.org/web/20191015052908/https://www.latimes.com/california/story/2019-10-06/oktoberfest-huntington-beach-transformer-blast-injured, accessed Oct. 1, 2026).

[703] Phase 4 Decision with Appendices (D.25-08-032 of Aug. 29, 2025). (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=578198350, accessed May 27, 2026). This decision closed R.20-07-013.

[704] D.25-08-032, Appendix A, Row 9, p. A-12.

[705] SPD calculation dividing pre-mitigation per-attribute consequence of a risk event (CoRE) value divided by pre-mitigation total CoRE, resulting in approximately 0.557 percent for safety, 95.417 percent for reliability, and 4.025 for financial, using numbers from SCE 2026 RAMP, Ch. 6, Table VI-16 "Summary of Proposed Plan Pre and Post LORE and CORE Risk Scores," p. 45.

[706] SCE 2026 RAMP, Ch. 6, pp. 6-7.

[707] SCE 2026 RAMP, Ch. 6, Figure II-3 "Underground Equipment Failure Bowtie," p. 9.

Observations and Findings

SCE's UEF risk bow tie has limited utility. Little distinguishes the driver "equipment facility failure" from the triggering risk event "underground equipment failure" besides SCE's decision to separate failures influenced by external factors into a second driver labeled "Other," which accounts for only about 0.8 percent of UEF events between 2020 and 2024.[708] SCE provides further specificity by separating the "Equipment Facility Failure" driver into sub-drivers (discussed in the later "Drivers" section of this report) categorized by type of underground equipment (e.g., cable, switch, etc.).[709] However, this distinction between "drivers" and "sub-drivers" also has limited utility: SPD finds SCE would have produced a much more informative bow tie had these sub-drivers been listed as drivers.

Exposure

SCE defines its underground equipment failure exposure as all primary distribution underground electrical equipment (less than 55 kilovolts). [710, 711] In other words, per SCE's risk description, the exposure to UEF risk encompasses all higher-voltage lines between the utility and the transformer. In its 2026 RAMP filing, SCE does not provide any additional information that clarifies what asset classes or how many of each are exposed to UEF risk. However, in response to a data request submitted by SPD, SCE provided the following information on assets exposed to UEF risk, focusing on the equipment SCE listed in its definition of equipment facility failures (see Table 3-1).[712]

[708] SPD calculation based on numbers from SCE 2026 RAMP, Ch. 6, Table II-4 "UEF Annualized Driver Frequency," p.9. SCE reports its total of UEF events between 2020 and 2024 as 10,697 and the total events assigned to the "Other" driver as 81, which is about 0.757 percent of the total.

[709] SCE 2026 RAMP, Ch. 6, p. 10.

[710] SCE 2026 RAMP, Ch. 6, Figure II-3 "Underground Equipment Failure Bowtie," p. 9.

[711] SCE 2026 RAMP, Ch. 6, Table II-3 "Underground Equipment Failure Chapter Scope," p. 8.

[712] SCE lists in its definition of equipment facility failure, "SCE-owned underground equipment such as cables, switches, transformers, and cable components (elbows, splices, and fuses)" per SCE 2026 RAMP, Ch. 6, p. 9. SCE includes capacitor banks in its list of equipment facility failure sub-drivers in SCE 2026 RAMP, Ch. 6, Table II-5 "Summary of UEF Sub-Drivers," p. 10.

Table 3-4. SCE Underground Equipment Failure Risk Exposure[713]

Equipment Type	Estimated System-Wide Underground inventory
Cable (in Conductor Miles)	41,987
Transformers	447,666
Switches	248,044
Capacitor Banks	2,716
Elbows	229,734
Splices	124,879
Fuses	19,009

Observations and Findings

SPD observes that SCE exposure to UEF risk is extensive. SCE operates a large network of over 40,000 circuit miles of underground lines, along with hundreds of thousands of associated assets.

Tranches

SCE employs a quintile tranching methodology for UEF risk, dividing its underground electric facilities into five risk-based tranches (quintiles), ranging from the lowest to the highest-risk assets, based on SCE'sUEF risk likelihood of a risk event (LoRE) and consequence of a risk event (CoRE) values. See Figure 3-2 for SCE's presentation of its risk tranches showing the lowest likelihood tranche with lowest consequences as

[713] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 44.

"L1-C1" and the highest likelihood tranche with highest consequence as "L5-C5."

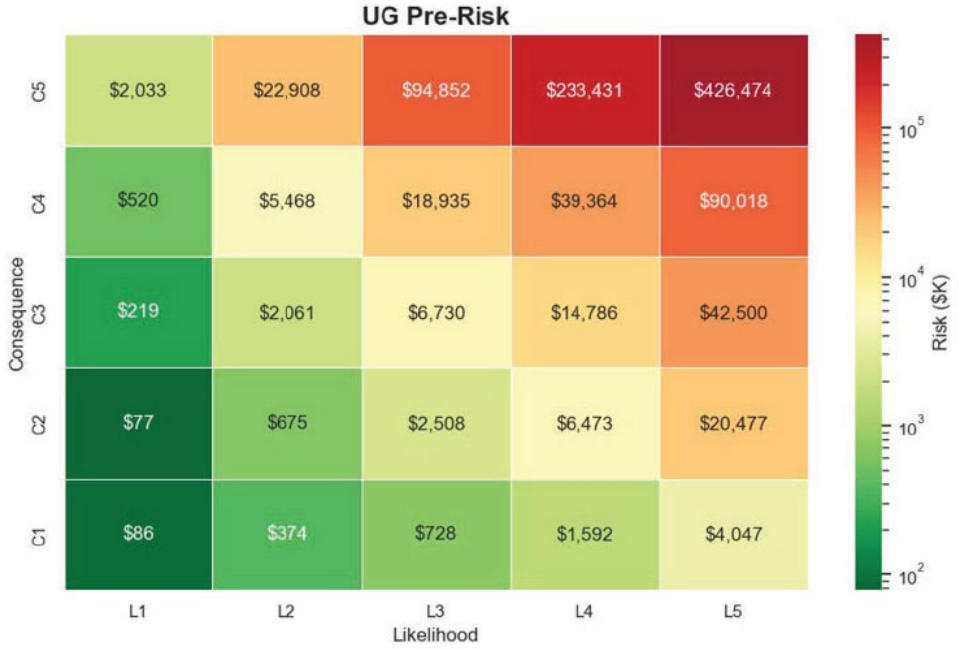


Figure 3-2. Quintile Tranching of Underground Equipment Failure Risk in 2029 Using LoRE and CoRE Values ($000s)[714, 715, 716]

Observations and Findings

SPD observes that SCE's quintile tranching approach is consistent with California Public Utilities Commission (CPUC or Commission) guidance from the RDF Phase 4 Decision.[717] The quintile approach allows for analysis that distinguishes between various homogeneous risk profiles.

Risk Reporting Units (RRUs)

As with overhead equipment failure risk, SCE defines polygon-based RRUs for OEF risk. SCE defines its polygon-based RRU for this risk as a "contiguous portion of a distribution circuit over which underground assets are electrically and operationally connected and typically fail, are restored, and are mitigated together."[718]

---

[714] SCE 2026 RAMP, Ch. 6, Figure II-4 "Underground Equipment Failures 2029 5x5 Unmitigated Tranching ($000s)," p. 13.

[715] SCE doesn't define the term "UG." SPD here glosses this term with "underground equipment."

[716] SPD understands the term "pre-risk" used in the label on the figure to mean "pre-mitigated risk."

[717] D.25-08-032, Appendix A, Row 14, pp. A-15-A-16.

[718] SCE 2026 RAMP, Ch. 6, p. 13

SCE argues the polygon approach to defining RRUs is superior to defining them either using circuits or individual underground asset segments because defining RRUs by distribution circuit "can obscure localized underground risk concentrations," while defining RRUs using individual assets, while highly granular, would result in "an impractically large number of units."[719]

Figure 3-3 is SCE's figure illustrating how a single distribution circuit is divided into polygon-based RRUs (in which SCE notes "color shading in [this figure] is for illustrative purposes only and does not represent prioritization, condition, or risk; it is intended solely to distinguish polygons along the Finch circuit and demonstrate typical polygon boundaries"[720]). SCE uses this figure to illustrate polygon-based RRUs for both overhead equipment failure risk and UEF risk.

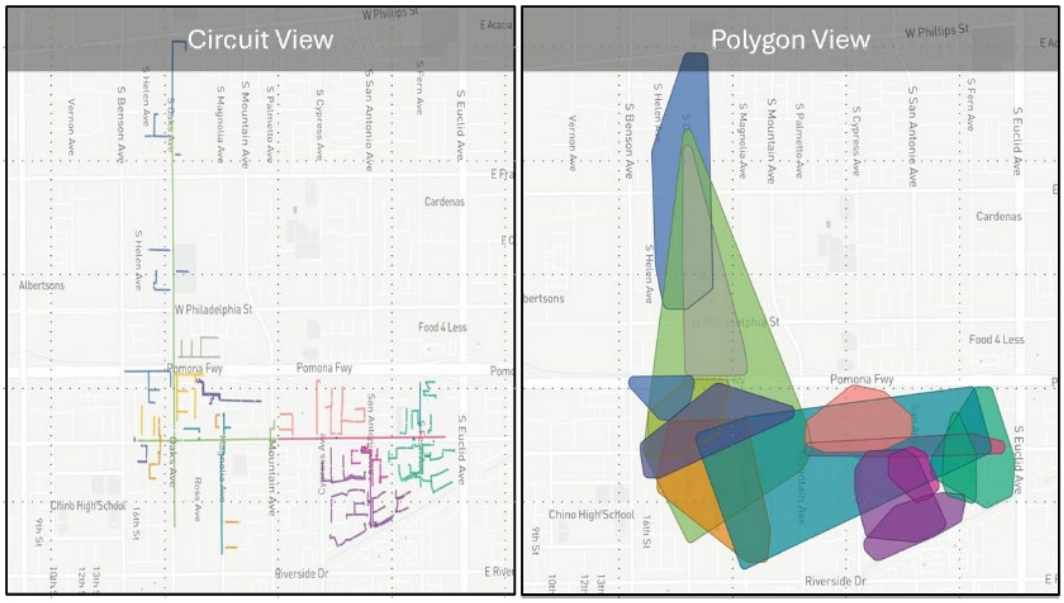


Figure 3-3. SCE's Illustration of the Finch Distribution Circuit Segmented by Polygons.[721]

Observations and Findings

SPD observes that SCE's approach to defining RRUs is consistent with Commission guidance. SCE's polygon approach to defining RRUs "reflects how underground work is performed in practice,"[722] accounting for both common patterns of failure and mitigation work. This level of analysis is more granular than at a distribution circuit level, but larger than at an individual electrical asset level.

---

[719] SCE 2026 RAMP Ch. 6, pp. 15-16.

[720] SCE 2026 RAMP Ch. 6, p. 15, footnote 16.

[721] SCE 2026 RAMP Ch. 6, Figure II-5 "Finch Distribution Circuit Segmented by Polygons," p. 15.

[722] SCE 2026 RAMP, Ch. 6, p. 14.

SPD also observes that defining RRUs using the polygon approach introduces a level of subjectivity to the process. SPD speculates whether two independent subject matter experts asked to divide the same electrical distribution system into RRUs using the polygon approach would define SCE's RRUs the same way.

Risk Drivers

In its risk bow tie, SCE presents two potential leading indicators for this risk, or drivers. The first driver, equipment facility failure, originating from SCE equipment or assets, is responsible for the vast majority of UEF events, accounting for 99.2 percent of UEF events between 2020 and 2024, while SCE indicates that the second driver, "other," only accounts for the remaining 0.8 percent of UEF events in the same period, as noted above.[723] The "other" category includes events caused by external forces such as environmental factors, weather, or animals (but excludes events caused by contact with energized equipment by employees, contractors, or the public, including through sabotage of equipment).[724]

SCE further divides the equipment facility driver into various sub-drivers, which it defines based on the asset class that triggers the UEF event, as described in Table 3-2.

Table 3-2. Summary of Underground Equipment Failure Sub-Drivers[725]

Driver	Sub-Driver	Share of Failure Impact[726]	Primary Consequences	Why This Driver Matters
Equipment facility failure (EFF)	Cable Failure	• High Frequency • High customer minutes interrupted (CMI)	Safety & Reliability	Primary contributor to UEF, cable degradation can lead to explosive events, prolonged outages, and emergency repairs, reinforcing the need for targeted cable replacement
EFF	Capacitor Bank Failure	• Low Frequency • Low CMI	Reliability & Financial	Failures are infrequent but can result in localized outages and costly repairs,

[723] SPD calculation based on numbers from SCE 2026 RAMP, Ch. 6, Table II-4 "UEF Annualized Driver Frequency," p.9. SCE reports its total of UEF events between 2020 and 2024 as 10,697 and the total events assigned to the "Other" driver as 81, which is about 0.757 percent of the total. SCE attributes the balance of UEF events to equipment facility failure.

[724] SCE 2026 RAMP, Ch. 6, p. 9

[725] SCE 2026 RAMP, Ch. 6, Table II-5 "Summary of UEF Sub-Drivers," p. 10.

[726] SCE appends the following explanation to this column (where CMI stands for customer minutes interrupted): "Share of Failure Impact reflects the relative occurrence of outage events over the 5-year period based on the distribution of annualized outage counts. Categories were assigned using tertile groupings of observed values (High: 575–1,073; Moderate: 131–575; Low: 3–131). CMI Impact reflects the relative magnitude of customer impact, measured as CMI, also grouped into tertiles based on observed data (High: 36.6–81.6 million; Moderate: 15.1–19.3 million; Low: 0.26–0.28 million). These categories support comparative assessment of reliability drivers and do not represent absolute performance thresholds," per SCE 2026 RAMP, Ch. 6, p. 10, footnote 11.

Driver	Sub-Driver	Share of Failure Impact[726]	Primary Consequences	Why This Driver Matters
				supports condition-based maintenance and targeted replacement
EFF	Other (Elbows/ Splices/ Fuses)	• Moderate Frequency • High CMI	Reliability	Known weak points in underground systems, failures can escalate outages and complicate restoration, supporting targeted component replacement and hardening
EFF	Switch Failure	• Moderate Frequency • Moderate CMI	Safety & Reliability	Impairs isolation and restoration capability, can lead to explosive events and prolonged outages, supports underground switch replacement and modernization to reduce outage duration
EFF	Transformer Failure	• High Frequency • Moderate CMI	Safety, Reliability & Financial	Can result in high-energy events and extended outages; supports condition-based maintenance and condition-driven mitigation
Other	Other (Animal / Weather)	• Low Frequency • Low CMI	Safety, Reliability & Financial	Residual category capturing non-systematic drivers; reinforces need for layered mitigation and inspection programs rather than single-driver solutions

Observations and Findings

SPD observes that SCE's selection of only two drivers for UEF risk provides little distinction other than to illustrate that the vast majority of UEF events originate from SCE asset failure rather than external causes. While SCE's further division of the equipment facility failure driver into sub-drivers based on asset class provides more information on the historic causes of UEF risk, and SCE notes that cable failure is a primary contributor to UEF,[727] it would be more helpful to see a breakdown of frequency of risk events caused by these sub-drivers over the period 2020 to 2024, which SCE only provides in aggregate for all equipment facility failure-related UEF events.

Consequences

UEF can result in a range of consequences, including service outages and violent explosions. As part of the RAMP process, SCE calculates the average consequence of a risk event (CoRE) for UEF risk before and after the utility's proposed mitigations, breaking it down into monetized consequences for the three attributes, safety, reliability, and financial, described in Table 3-3.

[727] SCE 2026 RAMP, Ch. 6, Table II-5 "Summary of UEF Sub-Drivers," p. 10.

Table 3-3. Pre- and Post-Mitigation Underground Equipment Failure Consequence of a Risk Event (CoRE) ($000s)[728]

Year	Safety CoRE ($000s)	Reliability CoRE ($000s)	Financial CoRE ($000s)	Total CoRE ($000s)
Beginning of 2029	$3.6	$616.3	$26.0	$645.9
End of 2032	$3.8	$610.2	$27.9	$642.0

Observations and Findings

SPD observes that the main challenge SCE faces in mitigating UEF risk is ensuring service reliability, with that attribute accounting for the vast majority of SCE's estimated consequence value. SPD also observes that SCE's proposed mitigation plan appears to focus on ensuring service reliability, given that it is the only attribute whose consequence value goes down from the beginning of the implementation period to the end.

While UEF can result in violent explosions, the physical barrier created by the equipment being placed underground provides significant protection against severe injuries and fatalities in most UEF events. However, given that the equipment is underground, a UEF risk event can also result in more extensive and prolonged outages than an overhead equipment failure event because of the protective physical barrier impeding repair crew access.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[729]

SCE proposes the following nine controls[730] and no mitigations[731] for UEF risk.

- Underground Cable Replacements (C1)
- Cable Life Extension (C2)
- Cable-in-Conduit Replacement (C3)
- Underground Structure Replacement Program (C4)
- Adjustable Vault Reinforcement (C5)

[728] SCE 2026 RAMP, Ch. 6, Table I-14 "Summary of Pre and Post LORE and CORE Risk Scores," p. 5

[729] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[730] SCE 2026 RAMP Ch. 6, Table III-6 "List of Controls Addressing Underground Equipment Failure," p. 17.

[731] SCE 2026 RAMP Ch. 6, p. 43.

- Cover Pressure Relief and Restraint (C6)
- Underground Switch Replacement (C7)
- Worst Performing Circuit (Underground) (C8)
- Underground Detail Inspections and Underground Preventive Maintenance (C9)

SCE proposes all nine controls in its proposed plan and first alternative plan, and seven of the controls in its second alternative plan (discussed further below).

As noted above, SCE does not introduce any mitigations in its 2026 RAMP application, instead relying on existing controls. SCE notes that developing "entirely new programs specifically targeted at UEF is inherently challenging because underground systems already benefit from a mature set of industry-standard design practices, inspection regimes, and asset management controls that significantly limit both failure frequency and incremental mitigation opportunities."[732]

Observations and Findings

SPD finds that SCE's nine controls represent a comprehensive approach to managing UEF risk. With these programs, SCE seeks to both proactively prevent asset damage and deterioration, as well as identify and remediate those assets that already show heightened risk of failure.

SPD understands SCE's decision not to propose any new mitigation programs for this risk, given SCE's existing number of mandated and industry-standard activities and the low frequency of safety-related risk events, making it possible that additional mitigation programs would not offer incremental improvements that would justify their costs.

Alternatives Analysis

SCE presents two alternative plans to address UEF risk. The first alternative plan includes the same nine controls as the proposed plan and the second alternative focuses on seven of the controls, expanding one of them into two programs. The alternative plans cost more than the proposed plan and differ only in allocation of funds and scope. SCE states that both alternatives reduce the overall effectiveness of SCE's UEF risk mitigation strategy compared to its proposed plan.[733] Table 3-4 provides a comparison of SCE's estimated spends for its proposed plan and both alternative plans.

[732] SCE 2026 RAMP Ch. 6, p. 43.

[733] SCE 2026 RAMP Ch. 6, p. 57.

Table 3-4. Underground Equipment Failure Estimated Spends for Proposed and Alternative Plans for 2029-2032 ($000s)

ID	Control	Proposed Plan[734]	Alternative Plan 1[735]	Alternative Plan 2[736]
C1	Underground Cable Replacements	$341,858	$341,858	$341,858
C2	Cable Life Extension	$123,017	$205,641*	$123,017
C3	Cable-in-Conduit Replacement	$396,992	$353,450*	$396,992
C4	Underground Structure Replacement Program	$258,485	$258,485	$325,899*
C5	Adjustable Vault Reinforcement	$15,526	$15,526	$0*
C6	Cover Pressure Relief and Restraint	$40,397	$40,397	$40,397
C7	Underground Switch Replacement	$59,232	$59,232	$0*
C8	Worst Performing Circuit (Underground)	$39,249	$39,246*	$39,249
C8a	Worst Performing Circuit - Switches			$122,418*
C9	Underground Detail Inspections and Underground Preventative Maintenance	$1,308,488	$1,308,488	$1,308,488
	Plan Total	**$2,583,243**	**$2,622,322***	**$2,698,318***

*Change from proposed plan spend.

In the first alternative, SCE assesses the impact of shifting all proactive Cable-in-Conduit Replacement (C3) remediation scope to the Cable Life Extension program (C2), moving $43.542 million from one program to the other, with no other changes to the proposed plan.[737] SCE states that this has the benefit of "deferring certain capital replacement costs by using cable testing, which could confirm actual degradation prior to replacement and reduce reliance on model-based assumptions," but comes with tradeoffs including possibly increased service disruption.[738]

In the second alternative, SCE assesses the impact of integrating the Underground Switch Replacement (C7) scope into the underground Worst Performing Circuit program (C8) as an added component (C8a), reducing the Adjustable Vault Reinforcement program (C5) to zero, and shifting "underground structure

[734] SCE 2026 RAMP Ch. 6, Table VI-17 "Proposed Plan Programmatic Estimated Spend and Benefit Cost Ratios," p. 45.

[735] SCE 2026 RAMP Ch. 6, Table VII-24 "Alternative Plan #1 Programmatic Estimated Spend and Benefit Cost Ratios," p. 52.

[736] SCE 2026 RAMP Ch. 6, Table VII-29 "Alternative Plan #2 Programmatic Estimated Spend and Benefit Cost Ratios," p. 56.

[737] SCE 2026 RAMP Ch. 6, p. 49; SPD calculation of difference in program spends based on numbers in SCE 2026 RAMP Ch. 6, Table VII-22 "Comparison of Proposed Plan and Alternative Plan #1 — CLE and CIC Replacement Scope and Costs (2029–2032)," p. 49.

[738] SCE 2026 RAMP Ch. 6, p. 50.

remediation toward full structure replacements" through the Underground Structure Replacement program (C4).[739]

In terms of total risk reduction, over 2029-2032 SCE estimates the proposed plan should reduce risk $47.863 million, the first alternative to reduce risk $51.449 million, and the second alternative to reduce risk by the same amount as the proposed plan.[740] In terms of benefit-cost ratios (BCRs), SCE calculates an overall BCR of 2.27 (hybrid) for the proposed plan, the same BCR for the first alternative, and a slightly lower BCR for the second alternative, 2.14 (hybrid).[741] The full set of SCE's plan BCRs along with estimated total plan spends is presented in Table 3-6.

Table 3-6. Underground Equipment Failure Proposed Plan and Alternative Plans Summary of Estimated Spends and Benefit Cost Ratios for 2029-2032 ($000s)[742]

Plan	O&M	Capital	Total	WACC BCR	Societal BCR	Hybrid BCR
Proposed Plan	$52,199	$2,531,045	**$2,583,243**	1.78	3.89	2.27
Alternative Plan 1	$52,199	2,570,124	**$2,622,322**	1.79	3.87	2.27
Alternative Plan 2	$52,199	$2,646,120	**$2,698,318**	1.69	3.69	2.14

Observations and Findings

Given the mature nature of industry management of underground electrical equipment, SPD observes that any alternative plans would involve minor changes to SCE's proposed plan for UEF risk mitigation. SPD also observes that the BCRs (a measure of cost-effectiveness) are very similar between all three plans. SPD further observes that SCE forecasts higher costs to perform either alternative plan relative to the proposed plan, while achieving either slightly higher risk reduction at the same cost-effectiveness (first alternative) or the same risk reduction with lower cost-effectiveness (second alternative) as the proposed plan.[743] Given the tradeoffs SCE describes for the first alternative, including increased service disruption, SPD observes that is logical for SCE to select the proposed plan.

---

[739] SCE 2026 RAMP Ch. 6, p. 53.

[740] SPD calculation based on numbers in SCE 2026 RAMP Ch. 6, Table VII-20 "Underground Equipment Failure Proposed Plan and Alternative Plans Summary of Pre and Post LORE and CORE Risk Score," p. 48.

[741] SCE 2026 RAMP Ch. 6, Table VII-21 "Underground Equipment Failure Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 48.

[742] SCE 2026 RAMP Ch. 6, Table VII-21 "Underground Equipment Failure Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 48.

[743] Table VII-20 SCE 2026 RAMP Chapter 6 SCE-Underground Equipment Failure, p. 48

BCR Calculations

SCE calculates BCR values for its nine UEF controls, providing three discount rate scenarios, a weighted-average cost of capital (WACC) rate, a societal rate, and a hybrid rate, described in Table 3-5.

Table 3-5. Underground Equipment Failure Risk Proposed Plan Programmatic Estimated Spend and Benefit Cost Ratios for 2029-2032 ($000s)[744]

ID	Control	Operations and Maintenance (O&M)	Capital	Total	WACC BCR	Societal BCR	Hybrid BCR
C1	Underground Cable Replacements		$341,858	$341,858	1.01	3.04	1.36
C2	Cable Life Extension		$123,017	$123,017	4.25	6.53	5.08
C3	Cable-in-Conduit Replacement		$396,992	$396,992	1.87	5.71	2.54
C4	Underground Structure Replacement Program		$258,485	$258,485	0.06	0.14	0.08
C5	Adjustable Vault Reinforcement		$15,526	$15,526	0.13	0.15	0.14
C6	Cover Pressure Relief and Restraint		$40,397	$40,397	0.05	0.09	0.06
C7	Underground Switch Replacement		$59,232	$59,232	1.44	2.93	1.82
C8	Worst Performing Circuit (Underground)		$39,249	$39,249	0.54	1.44	0.72
C9	Underground Detail Inspections and Underground Preventative Maintenance	$52,199	$1,256,289	$1,308,488	2.19	4.33	2.74
	Proposed Plan Total	**$52,199**	**$2,531,045**	**$2,583,243**	**1.78**	**3.89**	**2.27**

Observations and Findings

SCE's proposed plan programmatic BCRs are all relatively low, ranging between 0.06 and 5.08 (hybrid) with an average BCR (hybrid) of about 1.65 (SPD calculation), compared to BCRs of several other risk mitigation programs in its 2026 RAMP. For example, the wildfire mitigation BCRs range between 0.09 and 40.65

[744] SCE 2026 RAMP Ch. 6, Table VI-17 "Proposed Plan Programmatic Estimated Spend and Benefit Cost Ratios," p. 45.

(hybrid) with an average BCR (hybrid) of about 9.15 (SPD calculation).[745] SPD observes that throughout SCE's RAMP application, risks that are managed partly or fully through programs dictated by compliance requirements and other regulatory direction tend to have programs with relatively low BCRs, which may be the case here. In particular, SCE calculates very low BCRs for Underground Structure Replacement (C4) at 0.08 (hybrid), Adjustable Vault Reinforcement (C5) at 0.14 (hybrid), and Cover Pressure Relief and Restraint (C6) at 0.06 (hybrid). These three programs focus on physical protections that serve to prevent exterior damage to electrical equipment and to protect any utility workers, emergency responders, and the public in the event of a catastrophic failure that may cause a fire or explosion. As such, the three controls' low BCRs appear to be a result of the low impact that safety consequences have on the UEF risk score and the low frequency of external damage as a driver.

Conversely, SCE calculates higher BCRs for programs that seek to address proactively the primary driver of energized equipment failure (originating from SCE assets). The three highest UEF control BCRs belong to Cable Life Extension (C2) with 5.08 (hybrid), Cable-in-Conduit Replacement (C3) with 2.54 (hybrid), and Underground Detail Inspections and Underground Preventative Maintenance (C9) with 2.74 (hybrid). These programs' relatively high BCRs may be elevated by their positive impact on service reliability, given that outages caused by UEF are sometimes prolonged due to the extra challenges associated with repairing underground electrical equipment.

Summary of Findings

SPD finds that:

1. SCE excludes secondary impacts from outages from its scope for UEF risk.
2. SCE would have produced a much more informative bow tie had the equipment facility failure sub-drivers been listed as drivers.
3. Although SCE's provision of a list of equipment facility failure sub-drivers is helpful, given that this driver is responsible for more than 99 percent of UEF risk events, it would be more helpful if SCE provided the frequency of risk events caused by these sub-drivers instead of just an aggregate number of risk events for the overarching driver for 2020-2024.

Recommendations to Address Findings

SPD recommends that SCE:

1. Consider including in its scope for UEF risk the secondary impacts of outages with safety and reliability ramifications, adding the estimated costs of these impacts to its calculation of the consequences of a risk event (CoRE), particularly in the case of the more severe outcomes.

[745] SCE 2026 RAMP Chapter 4 "Wildfire and PSPS," Table VII-34 "Proposed Plan Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios," p. 80.

2. In its UEF risk bow tie, list the equipment facility failure sub-drivers as drivers and provide the frequency of risk events they caused over the last five years instead of just an aggregate number of risk events for the overarching driver.

4. Employee Safety Risk

Risk Description

The Southern California Edison Company (SCE) defines employee safety risk as incidents involving an SCE employee or employees "leading to Serious Injury or Fatality (SIF) events, Potential Serious Injury or Fatality (PSIF)s, and Days Away, Restricted, or Transferred (DART)."[746, 747]

This definition includes two changes from the definition in SCE's 2022 Risk Assessment and Mitigation Phase (RAMP) application. First, the utility preserves serious injury or death within the risk definition to comply with guidance by its national trade association and explains that said trade group narrowed the scope of qualifying events to only those considered "life altering."[748] The second element of the risk definition revision is an expanded qualifying scope to also include (1) those incidents that rise to a level considered Potential Serious Injury or Fatality, or ones that were averted, perhaps so close as to be near-misses; as well as (2) DART incidents.

SCE estimates employee risk to increase over the General Rate Case (GRC) cycle 2029-2032, from a value on January 1, 2029, of $52.84 million, to a value on December 31, 2032, of $57.87 million. The increase is due to SCE's plan to maintain a constant level of risk in natural units while SCE expects the monetization value to escalate each year.[749, 750, 751] These risk scores are lower than corresponding values SCE presents for contractor safety risk.

In response to this risk value approaching $60 million, SCE proposes spending $83.1 million annually and $332.4 million cumulatively over the four-year funding period 2029-2032. These spending-to-risk ratios are

---

[746] SCE 2026 RAMP, Chapter 7 "Employee Safety," p. 4.

[747] SCE 2026 RAMP Ch. 7, Figure II-1 "Risk Bowtie for Employee Safety," p. 7.

[748] An example would be that whereas before, under the 2022 definition, a broken leg would have qualified as a SIF, under the new definition a qualifying leg injury would need to amount to loss of use of leg or worse.

[749] SCE 2026 RAMP Ch. 7 work paper "Employee Safety - Overall Residual Risk Calculations.xlsx" spreadsheet, tabs "Employee Safety Chart" and "Employee Table."

[750] Safety Policy Division (SPD) raised the question of why the risk value for employee safety risk was expected to grow steadily despite SCE's expenditure of $332.4 million. SCE responded that the utility's menu of risk controls within its proposed plan is "intended to maintain current risk levels and prevent increases in risk that could occur in their absence. Accordingly, a stable modeled likelihood should not be interpreted as an absence of program value, but rather as an indication that existing controls are sustaining risk at current levels," per SCE response to Data Request SPD-SCE-2026RAMP-005, Question 53.

[751] SPD raised the question a second time, rephrasing to ask why the risk value for employee safety risk was expected to grow steadily despite SCE's expenditure of $332.4 million. SCE responded that the utility's risk model does not fully capture all factors that would demonstrate risk reduction and that the BCR ratio is one of several metrics by which to gauge the effectiveness of a program's ability to control risk, per Data Request SPD-SCE-2026RAMP-012, Question 1.

the inverse of SCE's treatment for its contractor safety risk. There, we see SCE spending on related risk-reduction efforts that fall below the value of the risk. Additional key values that illuminate the utility's spending for this risk, in the context of the risk's magnitude, can be found in the exposure section discussion below.

Observations and Findings

SCE's proposed expenditure levels would, by some measures, have the utility spending at more than 150 percent of the value of the risk. Although such a spending level would appear excessive, in the context of other big California investor-owned utility (IOU) spending for this risk category, SCE's spending is not so out of the ordinary. This subject is addressed further in the Benefit-Cost Ratio (BCR) section below. As detailed later in this staff assessment, SCE proposes no capital spending, with all costs occurring in the operations and maintenance (O&M) category, and SCE proposes no new mitigation measures as part of its proposed plan, with all risk reduction efforts tied to continuing existing controls.

It's notable that the 2026 SCE RAMP marks the first time that Safety Policy Division (SPD) has evaluated this risk category for SCE. SCE introduced employee safety as a standalone primary RAMP risk chapter within its 2022 RAMP application, but SPD provided no assessment within its corresponding staff report. SCE had previously addressed the subject within its inaugural 2018 RAMP report, but the subject matter was just one within a broader risk chapter titled "Employee, Contractor & Public Safety." At the time, SPD noted the chapter risk within its corresponding 2019 staff report, providing a limited one-page summary, most of which noted the California Public Utilities Commission's (CPUC's or Commission's) jurisdiction over energy-utility safety. As such, the critical analysis offered here is the first for an SCE RAMP Employee Safety risk chapter. This comes in the wake of Sempra's 2025 RAMP and Pacific Gas and Electric Company's (PG&E's) 2024 RAMP, both of which received thorough written scrutiny on their respective Employee Safety risk chapters, providing early guidance for SCE of what it would be expected to emulate within its own RAMP effort. SPD's Risk Assessment unit, since 2024, has conducted thorough oversight of this risk area enabled by divisional expansions and staff reassignments.

Risk Bow Tie

SCE presents the following risk bow tie for employee safety risk:

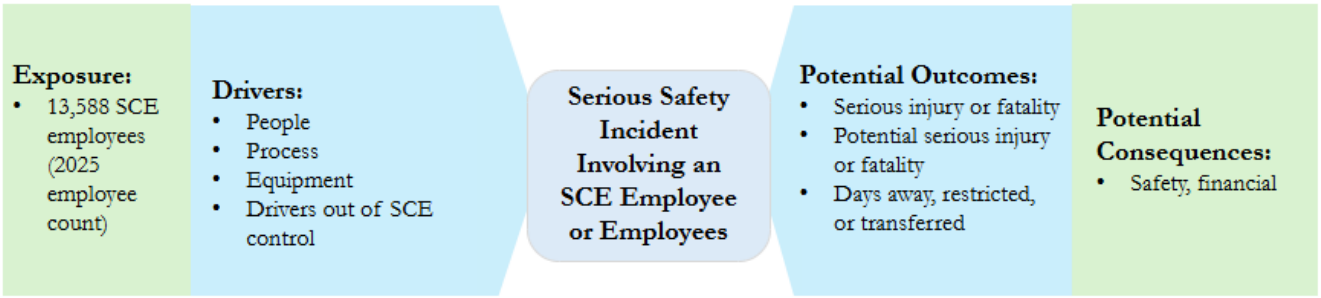


Figure 4-1. SPD Adaptation of SCE Employee Safety Risk Bow Tie[752]

Observations and Findings

SCE's risk bow tie diagram does not include many relevant and useful elements associated with a high-level risk dashboard profile. Key data points absent on the driver side of the bow tie include risk score, frequency, percent frequency, and percent of risk; while data points absent on the potential outcome and consequence side include consequences of a risk event (CoRE), percent frequency, and percent of risk. Rather, the bow tie as submitted is too limited to satisfy the purpose of providing a useful all-in-one overview dashboard that encapsulates key characteristics that define the primary risks detailed in the chapter.

SPD expressed similar concern last year within feedback provided on Sempra's 2025 RAMP application, citing earlier such criticism within SPD's review of the Sempra 2021 RAMP, stating that the Sempra utilities "should clearly state or show which risk drivers or triggers (DTs) and potential consequences (PCs) are their priorities in the risk bow tie, using frequencies and/or rankings."[753]

[752] SCE 2026 RAMP Ch. 7, Figure II-1 "Risk Bowtie for Employee Safety," p. 7.

[753] Safety Policy Division Staff Evaluation Report on SDG&E's and SoCalGas' Risk Assessment and Mitigation Phase (RAMP) Application Reports (A.) 21-05-011, (A.) 21-05-014 (Nov. 2021), p. 85 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/spd-evaluation-of-sdge-and-socalgas-2021-ramp-report_110521.pdf, accessed Oct. 6, 2026).

Exposure

SCE states that the number of personnel in its employ "is a key factor in the exposure that this risk presents."[754] SCE also indicates that its number of in-house employees stands at 13,588. [755, 756, 757] In the absence of a superior metric, SPD will use it as the basis for appraising the reasonableness of this element of SCE's Employee Risk chapter. Factoring the 13,558 number with the number of paid-hours, 2,080, the number of paid-hours in the typical U.S. work year,[758] equates to 28.2 million SCE annual worker hours, a second measure of risk exposure.[759]

Observations and Findings

It is unclear why SCE does not directly explain and justify its choice to use number of employees as its exposure metric. But clearly, a pool of people in itself does not constitute exposure to risk, it is only when those people are put in a position to be placed in harm's way that any risk exposure exists. Put differently, if SCE's workforce were entirely home-based, its exposure would look very different from one entirely field-based.

As such, SCE's exposure metric comes into a more useful focus when viewed through the lens of how its workforce is categorized, and whether personnel are office- or field-based. This is because of how SCE defines exposure for its employee risk with qualifying safety incidents including only those that result in serious injury or death or interruption in the employee's ability to carry out typically assigned duties. Naturally, such a standard would pertain more to field-based incidents. As such, given that SCE is an organization whose workforce composition is more than two-thirds individuals who are office-based workers, such an application of exposure criteria would seem an awkward fit, although SCE has assigned tranches for risk analysis by categories such as office and field employees.

---

[754] SCE 2026 RAMP Ch. 7, p. 5.

[755] SCE 2026 RAMP Ch. 7, Figure II-1 "Risk Bowtie for Employee Safety," p. 7.

[756] SCE 2026 RAMP Ch. 7, Table II-8 "SCE's Employee Safety, Employee Count (2025), and Pre-and-Post Risk Score," p. 13.

[757] SCE offers conflicting figures on its precise 2025 employee workforce number, stating, "In 2025, SCE's employee workforce consisted of approximately 13,300 employees (counting both field employees and office employees)," per SCE 2026 RAMP Ch. 7, p. 5.

[758] My Hours, How Many Work Hours in a Year? Full Guide for 2026 (2026) (https://myhours.com/articles/how-many-work-hours-in-a-year, accessed Oct. 6, 2026).

[759] Actual hours worked may vary when accounting for days off due to federal and state holidays or paid time off.

Table 4-1. SPD Breakdown of SCE Employees by Tranche Category[760]

ID	Category of Employee	Employee Count	Percent[761]	Annual Hours Worked[762]	Percent of Hours[763]
T1	Office	9,152	67.50	19,036,160	67.50
T2	Field (High Hazard)	1,723	12.71	3,583,840	12.71
T3	Field (Other)	2,683	19.79	5,580,640	19.79
	Totals	13,558	100.00	28,200,640	100.00

As indicated above, for its 2026 RAMP, SCE's employees number 13,558 with (per SPD calculation) about 28.2 million employee annual hours worked. The average monetized value of risk for the GRC period is $55.35 million per year.[764] The average proposed risk prevention spend is $83.1 million per year.[765]

Working from these numbers, SPD calculated the following:

- Per-hour planned annual spending on Employee Safety: $2.95
- Per-hour value of Employee Safety risk: $1.96
- Per-worker planned annual spending: $6129
- Per-worker annual value of Employee Safety risk: $4,082

Additionally, given that the annual number of qualifying incidents for this risk is 209.4 per year, 766 SPD calculates a resulting average monetized risk value of $264,326 per incident, with a corresponding risk prevention spend per incident of $396,848.

[760] SCE 2026 RAMP Ch. 7, Table II-8 "SCE's Employee Safety, Employee Count (2025), and Pre-and-Post Risk Score," p. 13.

[761] SPD calculation.

[762] SPD calculation of hours worked assuming a standard 2,080-hour work-year.

[763] SPD calculation.

[764] SPD calculation of the average monetized value of risk based on SCE 2026 RAMP Ch. 7, Table I-1 "Summary of Pre- and Post- LORE and CORE Risk Scores." SPD took the average of the proposed plan's pre-mitigation risk ($52,839,000) and post-mitigation risk ($57,870,000), which is $55,354,500.

[765] SPD calculation of the average proposed risk prevention spend per year based on SCE 2026 RAMP Ch. 7, Table VII-14 "BCR Values for Proposed Plan Controls," p. 42. SPD took the total estimated cost of the proposed plan for 2029-2032 ($332,421,000) and divided it by four, which is $83,105,250.

[766] SCE 2026 RAMP Ch. 7, Table II-3 "Historical Driver Information," p. 8.

For comparison purposes, for SCE's evaluation of employee safety risk, we find much lower risk values and costs coupled with significantly higher spending levels for risk reduction than is the case for contractor safety risk.

SPD analysis of the risk per worker, shown in Table 4-2 below, finds that the risk exposure per contractor worker for SCE's most high-hazard contractor activities, by SPD calculation at $15.9 thousand of monetized risk per worker (Contractor Risk Tranche 1), trails certain high-risk in-house activities, with SPD's calculation of risk per worker at $21.75 thousand (Employee Risk Tranche 2).[767, 768] SPD observes that it appears that SCE does not rely on contractors to perform exclusively the most dangerous utility work, at least by one measure.[769] This observation is not to downplay the significance of SCE's contractor field-assigned high-hazard workforce exposure with 18.43 million annual hours worked, compared with SCE in-house field-assigned high-hazard employees who account for 3.58 million annual hours worked .[770] Another metric: consider that SCE's contractor workforce is responsible for 100 percent of all SCE high-hazard tree trimming, tree removal, and other vegetation management activities.[771]

SCE's treatment of exposure has implications for its risk tranches, the subject of our next discussion.

Tranches

SCE departs from the default quintile tranching methodology for this risk.

SCE defines three tranches for this risk:[772]

- Office employees (T1)
- Field Employees: Lineman/Journeyman, Apprentice, Troubleman, and Groundman (T2)
- Field Employees: All other field workers (T3)

Observations and Findings

As is the case with SCE's exposure criteria, the appropriateness of SCE's choice of tranches is better assessed in the context of where the bulk of the utility's risk share resides. Office workers, more than two-thirds of the SCE workforce, account for eight percent of the utility's risk, as shown in Table 4-2 below. As

---

[767] As shown in Table 4-2, Per-Employee Risk is the tranche risk value divided by the number of employees in that tranche.

[768] See also in this evaluation report Chapter 5 "Contractor Safety Risk," Table 5-2 "SCE Risk Driver Characteristics at a Glance."

[769] That measure, standalone per-worker risk value, can be more fully illuminated in the context of annual hours worked, where contracted hours worked total a multiple of in-house SCE employee field transmission and distribution activities.

[770] Table 4-1.

[771] SCE response to Data Request SPD-SCE-2026RAMP-012, Question 3(a).

[772] SCE 2026 RAMP Ch. 7, Table II-8 "SCE's Employee Safety, Employee Count (2025), and Pre-and-Post Risk Score," p. 13.

such, it bears pointing out that SCE could better explain how it simultaneously can include a risk tranche for office workers while at the same time adopting a qualifying risk definition that largely does not apply, by at least one measure, to this class of workers.

A related concern is SCE's departure from Commission requirements that utilities incorporate tranches that represent relatively homogeneous quantities of risk.[773] Table 4-2 below ("Per Employee Risk" column) reveals that high-hazard field-based workers have a risk value significantly greater than either of the other two tranches. The table compares SCE's tranche-specific estimates of the likelihood of a risk event (LoRE) and consequence of a risk event (CoRE) for each of the attributes (safety, reliability, and financial), the total of the CoRE for the three attributes (CoRE total), and the risk total (LoRE times CoRE total), additionally comparing the tranches by SCE's employee count and SPD's estimate of the number of hours worked by each tranche.

[773] SCE provided a paper with a brief description covering both Employee and Contractor Safety risk and the utility's approach to and justification for its tranche assignments, which SCE indicates are necessitated by its absence of CoRE and LoRE data at the worker level. Source: SCE 2026 RAMP Tranching White Paper, November 3, 2025.

Table 4-2. SPD Breakdown of Risk Tranches to Derive Per-Employee Risk ("Pre-Mitigation") ($000s)[774]

ID	Tranche	LoRE	CoRE Safety	CoRE Financial	CoRE Total	Risk Total	Per Employee Risk[775]	Employee Count[776]	Annual Hours Worked Millions[777]	Percent Hours Worked[778]
T1	Office employees	21	104	101	205	4,305	0.47	9,152	19.04	67.5
T2	Field Employees (High Hazard)	70	446	86	532	37,240	21.75	1,723	3.58	12.7
T3	Field Employees (Other)	36	210	100	310	11,160	4.12	2,683	5.58	19.8
	Totals	127				52,839				100

In response to a data request, SCE provided supplemental data, some of which run contrary to what one might intuit. Given the greater gravity of the qualifying incidents that are attributed to field-based workers, one might expect that the five percent of safety risk attributed to office staff would come with a disproportionately large volume of DART incidents. And yet, office staff account for just 13.9 percent of the 940 total DART incidents that SCE recorded from 2021 through 2025.[779]

In Table 4-3 below, SPD shows how for pre-mitigation risk its calculation of total risk (LoRE times CoRE total) differs from SCE's calculations as presented in its Table VII-13 "Pre- and Post- LoRE, CoRE and Risk Scores." SPD observes that the appearance of miscalculations by SCE impeded its evaluation, given that the differences appeared to be larger than what SPD would expect from a rounding error. For example, the differences for T2, T3, and Total are larger than typical rounding results. SCE explained in data request responses that it calculated totals for LoRE and CoRE using source numbers that were calculated out many

774 SPD calculations based on SCE 2026 RAMP Ch. 7, Table VII-13 "Pre- and Post- LoRE, CoRE and Risk Scores," p. 41.

775 SPD calculation, risk values in $000s.

776 SCE 2026 RAMP Ch. 7, Table II-8 "SCE's Employee Safety, Employee Count (2025), and Pre-and-Post Risk Score ($000s)," p. 13.

777 SPD calculation.

778 SPD calculation.

779 SCE response to Data Request SPD-SCE-2026RAMP-005, Question 47(c), in particular the table SCE submitted in response to SPD request for a "table showing number of DART events and the proportional share attributed to office- and field-based employees for a recent four- or five-year period."

significant digits beyond what SCE presents in its table presenting LoRE and CoRE.[780] SCE should have clarified in its presentation of LoRE and CoRE in its RAMP that the numbers in the table were truncated versions of the numbers SCE used to calculate its totals.

Table 4-3. Comparison of Pre-Mitigation Risk per Tranche per Table VII-13 versus SPD Calculation ($000s)[781]

ID	LoRE	Total CoRE	Total Risk per SCE (LoRE x Total CoRE)	Total Risk per SPD (LoRE x Total CoRE)
T1	21	$205	$4,305	$4,305
T2	70	$532	$37,480	$37,240*
T3	36	$310	$11,054	$11,160*
Total	127	$1,047	$52,839	$52,705*[782]

*SPD number differs from SCE number.

Risk Reporting Units (RRUs)

SCE did not define RRUs for this risk.

Observations and Findings

The RDF Phase 4 Decision requires that utilities define an RRU for each electric or gas operations mitigation, exempting the PSPS and protective equipment device settings mitigation categories.[783, 784, 785]

[780] SCE response Data Request SPD-SCE-2026RAMP-005, Questions 52 and 54.

[781] SCE 2026 RAMP Ch. 7, Table VII-13 "Pre- and Post- LoRE, CoRE and Risk Scores ($000s)," p. 41.

[782] SPD's different outcomes are due to rounding issues, per SCE response Data Request SPD-SCE-2026RAMP-005, Question 52.

[783] D.25-08-032, Appendix A, Definitions, p. A-7.

[784] D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[785] "The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following: 1. Public Safety Power Shutoffs; 2. Protective Equipment Device Settings; 3. Mitigation and Control Programs that do not meet the following thresholds: a. For PG&E and SCE, $10 million…" from D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

SPD observes that employee risk mitigation is not specific to electric operations risk mitigation and as such is not subject to the RRU requirement.

Risk Drivers

In its risk bow tie, SCE presents four potential leading indicators for this risk, or drivers:[786]

- People (D1)
- Process (D2)
- Equipment (D3)
- Drivers out of SCE control (D4)

Observations and Findings

SPD notes that the driver "people" (D1) alone accounts for over 92 percent of the total risk frequency.[787] SCE presents driver frequency data covering years 2021-2025 that, when compared with the prior five-year period of 2017-2021, demonstrates a marked increase (see Table 4-4 below).[788, 789] Given SCE's narrowing the scope of employee risk to only life-altering events one might intuit that the frequency of incidents would drop. But at the same time they have expanded the scope to include PSIF and DART incidents, so the overall numbers have increased ten-fold or more.

This large change in definition prevents comparison of incident data from the previous RAMP on a like-for-like basis. A supplemental presentation of 2021-2025 safety incident data using the previous definition would help illustrate the trend from one period to the next.

---

[786] SCE 2026 RAMP Ch. 7, Figure II-1 "Risk Bowtie for Employee Safety," p. 7.

[787] SCE 2026 RAMP Ch. 7, Table II-3 "Historical Driver Information," p. 8.

[788] SCE 2026 RAMP Ch. 7, Table II-3 "Historical Driver Information," p. 8.

[789] Application of Southern California Edison Company (U 338-E) Regarding 2022 Risk Assessment Mitigation Phase (RAMP) (May 2022) (SCE 2022 RAMP) Chapter 9 "Employee Safety," Table II-3 "Historical Driver Information," p. 8 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M476/K640/476640383.PDF, accessed Oct. 7, 2026).

Table 4-4. SPD Table of SCE Driver Frequency Comparing 2026 RAMP with 2022 RAMP[790,791]

ID	Driver	Total (2021-2025)	Annual Freq.	Percent Freq.[792]	Total (2017-2021)	Annual Freq.	Percent Freq. [793]	Incident Annual Increase[794]	Percent Annual Increase[795]
D1	**People**	965	193	92.17%	45	9	77.59%	184	2044%
D2	**Process**	27	5.4	2.58%	11	2.2	18.97%	3.2	145%
D3	**Equipment**	26	5.2	2.48%	1	0.2	1.72%	5	2500%
D4	**Drivers out of SCE control**	29	5.8	2.77%	1	0.2	1.72%	5.6	2800%
	Total	**1,047**	**209.4**	**100%**	**58**	**11.6**	**100%**	**989**	

SCE has put forward sub-drivers for the "people" and "process" drivers (D1 and D2).[796] A side-by-side comparison with SCE's approach to its 2026 RAMP with its prior 2022 RAMP[797] reveals that changes in the articulation of sub-drivers for these drivers vastly increased annual frequency for the "people" driver, with a smaller resulting increase for the "process" driver (see Tables 4-5 and 4-6 below).

[790] SCE 2026 RAMP Ch. 7, Table II-3 "Historical Driver Information," p. 8.

[791] SCE 2022 RAMP Ch. 9, Table II-3 "Historical Driver Information," p. 8.

[792] SPD calculation.

[793] SPD calculation.

[794] SPD calculation.

[795] SPD calculation.

[796] SCE 2026 RAMP Ch. 7, pp. 8-10.

[797] SCE 2022 RAMP Ch. 9, pp. 8-9.

Table 4-5. Risk Driver "People" (D1) Sub-Driver Frequency, 2026 versus 2022 RAMP[798, 799]

2026 RAMP Sub-Driver Approach	2026 RAMP Annualized Frequency	2022 RAMP Sub-Driver Approach	2022 RAMP Annualized Frequency
Complacency/ Overconfidence	109.2	Lack of Hazard Awareness	5
Human Performance/Not Following Rules	40.6	Work Practice	2
Hazard Identification Failure	40.2	Physical Capabilities	1
Fatigue	3.0	Adherence to Rules, Training or Policy	1
		Tools/ Equipment/ Operation	0[800]
Total	193		9

[798] SCE 2026 RAMP Ch. 7, Table II-4 "People RAMP Sub-drivers," p. 9.

[799] SCE 2022 RAMP Ch. 9, Table II-4 "People RAMP Sub-drivers," p. 9.

[800] SCE reported a total frequency for this sub-driver of 2 for the period 2017-2021 per SCE 2022 RAMP Ch. 9, Table II-4 "People RAMP Sub-drivers," p. 9.

Table 4-6. Risk Driver "Process" (D2) Sub-Driver Frequency, 2026 versus 2022 RAMP[801, 802]

2026 RAMP Sub-Driver Approach	Annualized Frequency	2022 RAMP Sub-Driver Approach	Annualized Frequency
Unfamiliar Conditions	4.4	Lack of Formal Process/ Poor Process	1.2
Inadequate Standards/ Work Practice/ Training/ Qualified Workers	0.6	Tools/ Equipment/ Operation	0.4
Ineffective Crew Communications	0.4	Working Conditions	0.4
		Lack of/Poor Communication	0.2
Total	5.4		2.2

SPD notes that one result of SCE's change in how it articulates its sub-drivers is that it eliminates overlap or duplication of sub-drivers across drivers as had existed for 2022 RAMP's Tools/Equipment/Operation sub-driver, which appeared within both D1 and D2.

Consequences

SCE's risk bow tie diagram reflects a change in the utility's consequences for this risk in the 2026 RAMP, having added financial impacts to safety impacts. The utility notes that financial impacts for this risk consist of workers' compensation claims resulting from an injury.[803]

The SCE risk bow tie diagram lists three outcomes for this risk:[804]

- Serious Injury or Fatality (SIF), contributing 2.0 percent of the outcomes.
- Potential Serious Injury or Fatality (PSIF), est contributing 8.4 percent of the outcomes.
- Days Away, Restricted, or Transferred (DART), contributing 89.6 percent of the outcomes.

[801] SCE 2026 RAMP Ch. 7, Table II-5 "Process RAMP Sub-Drivers," p. 10.

[802] SCE 2022 RAMP Ch. 9, Table II-5 "Process RAMP Sub-drivers," p. 10.

[803] SCE 2026 RAMP Ch. 7, p. 11.

[804] SCE 2026 RAMP Ch. 7, Figure II-1 "Risk Bowtie for Employee Safety," p. 7. SPD interprets the percentages attached to each outcome as the percentage of the total outcomes that each of the three outcome types contributes to the total.

SCE's treatment of its outcomes is new for 2026 as its prior 2022 RAMP had just one outcome: Serious Safety Incident (100 percent).

Observations and Findings

SPD notes that while the definition of serious injuries has narrowed, the total number of qualifying incidents has increased significantly, from a total of 58 risk events from 2017-2021 as reported in SCE's 2022 RAMP to 1,047 risk events from 2021-2025 as reported in SCE's 2026 RAMP.[805, 806] In response to a data request, SCE explained that it "expanded the set of in-scope events to include PSIFs and DARTs for Employee Safety and PSIFs for Contractor Safety. The inclusion of these additional, lower severity events increases the total number of reported events and explains the increase noted by SPD in its comparison to the 2022 RAMP chapters."[807]

According to SCE's reporting on incident likelihood,[808] non-SIF incidents account for 98 percent of the qualifying 2021-2025 safety incidents. SCE's past practice was to count only SIF and not the other, large inventory of safety events the utility is now including.

A confusing narrative in the RAMP chapter is found in SCE's discussion of outcomes where they state they have identified four (not three) outcomes and then just discuss one outcome.[809] In future RAMP reports, SCE should take more care to proofread and ensure consistency in narratives.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[810]

---

[805] SCE 2022 RAMP Ch. 9, Table II-3 "Historical Driver Information," p. 8.

[806] SCE 2026 RAMP Ch. 7, Table II-3 "Historical Driver Information," p. 8.

[807] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 49(a).

[808] SCE 2026 RAMP Ch. 7, Figure II-1 "Risk Bowtie for Employee Safety," p. 7. Note that the percent attached to each outcome in the original SCE diagram is not labeled in the diagram or in the main text. SPD is interpreting the percent as percent likelihood.

[809] SCE writes (bold added), "SCE has identified **four outcomes** for purposes of this RAMP filing: any incident resulting in a SIF (actual or potential) as defined by the EEI criteria and DART. **This outcome** indicates the relative likelihood of such outcome should the triggering events occur; and given that there is only one outcome, the likelihood is set at 100%," per SCE 2026 RAMP Ch. 7, p. 11. This language appears to be left over from SCE's 2022 RAMP, where we can read in the same section on outcomes and consequences the following: "SCE has identified one outcome for purposes of this RAMP filing: any incident resulting in a SIF, as defined by the EEI criteria. This outcome indicates the relative likelihood of such outcome should the triggering events occur and given that there is only one outcome, the likelihood is set at 100%," per SCE 2022 RAMP Ch. 9, p. 10.

[810] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

For this risk, SCE identified seven controls,[811] all included in SCE's proposed plan and alternative plans, and two mitigations associated with its two alternative plans.[812]

Of SCE's proposed seven controls, the utility would preserve three existing controls described in its 2022 RAMP, and add four new controls:

- Safety Culture Transformation (C1): Consultant expert serves as safety monitor, advisor and coach to facilitate goals and team events to promote a responsible safety culture culminating in the utility adopting and implementing an annual Safety Work Plan.
- Office and Industrial Ergonomics (new) (C2): Intended to reduce common field and office high-frequency injury risk by standardizing ergonomic assessments and training for both office- and field-based workers environments.
- Energy-Based Observations (new) (C3): Program to verify that safety measures are in place for high-energy hazards before work begins.
- Safety Observations Program (new) (C4): Identifies at-risk conditions and promotes safe practices through engagement, responsible safety culture, and prompt corrective action based on lessons learned.
- Human and Organizational Performance (C5): Intended to enable workers and management to proactively identify organizational and process deficiencies thereby averting safety risk drivers that lead to human error and safety lapses.
- High Hazard Safety Activities (new) (C6): Essentially a Safety Observations Program focusing on high-hazard operations workers.
- High Hazard Field Safety Training (C7): Includes in-depth training to prepare most at-risk field workers for career advancement into jobs that include groundman, lineman, and substation system operator.

The two mitigations SCE proposes as elements in its alternative plans are:

- Cognitive Behavioral Training (CBT) (M1), proposed as part of the first alternative plan: An element of Safety Culture Transformation (C1), this mitigation would expand the audience that would receive CBT.[813]
- Robotic Technologies (M2 or A2),[814] proposed as part of the second alternative plan: A pilot program wherein robotic technologies would conduct safety inspections in confined spaces.[815]

SPD discusses these further under Alternatives Analysis.

---

[811] SCE 2026 RAMP Ch. 7, Table IV-9 "Inventory of Employee Safety Controls," p. 15.

[812] SCE 2026 RAMP Ch. 7, Table V-10 "Inventory of Employee Safety Mitigations," p. 32.

[813] SCE 2026 RAMP Ch. 7, p. 32.

[814] The ID of the second mitigation is "M2" per SCE 2026 RAMP Ch. 7, Table V-10 "Inventory of Employee Safety Mitigations," p. 32; it is "A2" per SCE 2026 RAMP Ch. 7, Table VIII-18 "BCR Values for Alternative Plan #2 Controls," p. 48.

[815] SCE 2026 RAMP Ch. 7, p. 33.

SCE estimates a full cycle cost for its proposed plan for employee safety risk mitigation at about $332.4 million, which SPD calculates is about $83.1 million annually,[816] with the entire spend assigned to O&M; none assigned to capital improvements.[817] This level of spending is a large increase over the roughly $30 million annual spend described in the 2022 RAMP.[818] In response to a data request, SCE characterized the 2026 approach as "a broader set of employee safety controls and associated activities including training, compliance, and non-compliance related programs that support employee safety."[819] SCE added, "Some of these activities were reflected in SCE's TY 2025 GRC forecasts but were not fully captured within the Employee Safety mitigation portfolio presented in the 2022 RAMP," [820] meaning that the 2026 mitigation plan is more comprehensive in scope than the 2022 plan.

Observations and Findings

SPD observes that SCE's controls appear to be adequate and in line with industry standards. Having an emphasis on training and safety culture, these human-driven programs are fairly resource- and labor-intensive in that efforts and messaging typically require ongoing repeated sessions. SCE also describes systems that allow for data collection, trending, and assessment. SCE's controls describe a safety culture and workplace environment that encourages frank discussion of risk and hazardous conditions such that the subject can be openly addressed and conditions or incidents made teachable.

The utility's account of its control plan could be improved by clearer assurances that employees have some measure of immunity from discipline when coming forward to report a mistake, a violation of safety protocol, or an actual incident. That is to say, it would be reassuring to hear that SCE is actively championing practices that encourage parties involved in procedural lapses or safety incidents to make a no-fault report and have the experience added to the record of tracked safety data, in turn potentially enabling those involved as well as others to learn from the experience. These job characteristics—promoting a culture of open communication and capturing the value of teachable, if unflattering, moments—are valuable and align with contemporary industry standards.

---

[816] SPD calculation of the average proposed risk prevention spend per year based on SCE 2026 RAMP Ch. 7, Table VII-14 "BCR Values for Proposed Plan Controls," p. 42. SPD took the total estimated cost of the proposed plan for 2029-2032 ($332,421,000) and divided it by four, which is $83,105,250.

[817] SCE 2026 RAMP Ch. 7, Table VII-14 "BCR Values for Proposed Plan Controls," p. 42.

[818] SPD calculation based on SCE 2022 RAMP Ch. 9, Table VII-11 "Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)," p. 39. SCE did not provide a total estimated cost for its proposed plan in its 2022 RAMP. SPD calculates its total proposed plan by multiplying $30.05 million for O&M costs for one year (2025) by four for the full four-year cycle, and adding $1.20 million for capital costs for the full cycle, to get $121.4 million ($121,400,000). SPD divides that by four to get $30.35 million proposed annual spend.

[819] SCE response to Data Request SPD-SCE-2026RAMP-012, Question 6.

[820] SCE response to Data Request SPD-SCE-2026RAMP-012, Question 6.

The absence of mitigation measures in SCE's proposed plan means the utility's controls are doing the full job of reducing employee safety risk. SPD encourages SCE to consider and weigh new measures that may hold potential to make workers safer. At minimum, the utility should explain and justify the absence of new measures in future RAMP filings.

Additionally, SPD observes that SCE's proposed spending level could be considered somewhat in the mid-range of what is typical for a large California energy utility. Sempra's 2025 RAMP showed San Diego Gas & Electric Company (SDG&E) proposing to spend (per SPD calculation) $7.31 million per year on employee safety and Southern California Gas Company (SoCal Gas) proposing to spend $19.90 million per year on employee safety.[821] By contrast, PG&E put forward an Employee Safety risk reduction plan in its 2024 RAMP that proposed to spend $175.5 million annually (per SPD calculation).[822]

Alternatives Analysis

SCE presents two alternatives. Each introduces a mitigation, as noted above.

SCE proposes Cognitive Behavioral Training (CBT) (M1) as part of its first alternative plan. This training is an element of Safety Culture Transformation (C1). This mitigation would expand the audience receiving CBT from high-hazard field workers to the full workforce.[823]

SCE proposes Robotic Technologies (M2 or A2)[824] as part of its second alternative plan. In this pilot, robotic technologies would conduct safety inspections in confined spaces such as underground vaults.[825]

---

[821] Sempra 2025 RAMP Application: SDG&E 2025 Risk Assessment Mitigation Phase, Chapter SDG&E-Risk-6 "Employee Safety," Table 6 "Employee Safety Risk Control and Mitigation Plan – Recorded and Forecast Costs Summary," p. 25; Chapter SCG-Risk-5 "Employee Safety," Table 8 "Employee Safety Risk Cost Benefit Ratio Results Summary (2028-2031)," p. 27 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/2025-sempra-ramp-application.pdf, accessed Oct. 7, 2026).

[822] Pacific Gas and Electric Company 2024 Risk Assessment and Mitigation Phase Report, Chapter 3 Risk Assessment and Mitigation Strategy: Employee Safety Incident, Table 3-9 "Controls Cost Estimates, Risk Reduction, and CBR 2027-2030," p. 3-38 (PDF p. 852); Table 3-10 "Mitigation Cost Estimates, Risk Reduction, CBR, and Factors Affecting Selection," p. 3-40 (PDF p. 854) (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf, accessed Oct. 7, 2026).

[823] SCE 2026 RAMP Ch. 7, p. 32.

[824] The ID of the second mitigation is "M2" per SCE 2026 RAMP, Table V-10 "Inventory of Employee Safety Mitigations," p. 32; it is "A2" per SCE 2026 RAMP, Table VIII-18 "BCR Values for Alternative Plan #2 Controls," p. 48.

[825] SCE 2026 RAMP Ch. 7, p. 33.

SCE estimates a benefit-cost ratio (BCR) for the CBT mitigation at 0.10 (hybrid)[826] while it estimates a much higher BCR for the Robotic Technologies mitigation, at 15.60 (hybrid).[827]

SCE rejects both alternatives. SCE rejects the first alternative because, although opening CBT to the full workforce "may provide broader cultural benefits," SCE notes that "the incremental risk reduction associated with expanding training to lower-risk populations does not appear to justify the additional cost when compared to targeted investment in high-hazard employees."[828] SCE rejects the second alternative because of "safety assurance gaps associated with reliance on robotic inspections," such as robotic systems possibly failing to "detect certain hazards, potentially leading to false assumptions that an area is safe for entry." [829] The relatively high BCR of that program does not appear to offset its introduction of "unacceptable uncertainty." [830]

Observations and Findings

SPD observes that SCE's alternative plans fall short because they do not detail two comprehensive plan alternatives with multiple measures that the utility explains and justifies not undertaking. Rather, in crafting alternative plans, SCE offers single mitigation measures that make both alternatives slight variations of its proposed plan. Further, the Robotic Technologies mitigation has an unrealistic "Blue Sky" nature. SCE is compelled to reject the proposal because the available technology is not fully mature or tested.

A supplemental alternative that could help inform the value of the proposed plan would be a counter-factual scenario of a no-build plan. SPD has noted that it expects the proposed plan to maintain risk at a constant level in natural units through the rate case period, while monetized risk is expected to rise due to annual escalation of the dollar value. A no-build plan would make clear the level of risk that would increase in the absence of the proposed plan.

SCE's alternative plans need further development as they consist of just a single added measure tacked onto plans already underway.

BCR Calculations

SCE calculates BCR values for its six controls and two mitigations for employee safety risk. SCE presents all BCRs, as required, under three discount rate scenarios: a weighted-average cost of capital (WACC) rate, a societal rate, and a hybrid rate.

---

[826] SCE 2026 RAMP Ch. 7, Table VIII-16 "BCR Values for Alternative Plan #1 Controls," p. 46.

[827] SCE 2026 RAMP Ch. 7, Table VIII-18 "BCR Values for Alternative Plan #2 Controls," p. 48.

[828] SCE 2026 RAMP Ch. 7, p. 44.

[829] SCE 2026 RAMP Ch. 7, p. 47.

[830] SCE 2026 RAMP Ch. 7, p. 47.

Table 4-7 presents SCE's projected BCRs for the seven controls in SCE's proposed plan for mitigating employee safety risk.

Table 4-7. BCR Values for Proposed Plan Controls[831]

ID	Control	BCR (Societal)	BCR (WACC)	BCR (Hybrid)
C1	Safety Culture Transformation	1.33	1.33	1.41
C2	Office and Industrial Ergonomics	0.17	0.17	0.18
C3	Energy-Based Observations	0.64	0.64	0.68
C4	Safety Observations Program	3.06	3.06	3.25
C5	Human and Organizational Performance	3.82	3.81	4.04
C6	High Hazard Safety Activities	0.69	0.69	0.73
C7	High Hazard Field Safety Training	0.02	0.02	0.02
	Total	**0.32**	**0.32**	**0.34**

Observations and Findings

SPD observes that SCE's control BCRs fall within a range of 0.02 at the lowest to 3.82 at the highest. Given that SCE proposes to spend $83.1 million annually[832] and $332.4 million cumulatively for the four-year funding period 2029-2032[833] on employee safety risk reduction, SCE's spending approach will fall well below a BCR break-even point of 1.0. Looking at the risk reduction SCE estimates for the proposed plan, SPD observes that SCE expects post-mitigation risk to be higher than pre-mitigation risk (by about $5 million).[834]

SPD asked SCE in a data request "How does SCE justify the continuation of programs with such low BCRs and no apparent risk-reduction value?"[835] In justifying its approach, SCE responded that, "Employee Safety

[831] SCE 2026 RAMP Ch. 7, Table VII-14 "BCR Values for Proposed Plan Controls," p. 42.

[832] SPD calculation of the average proposed risk prevention spend per year based on SCE 2026 RAMP Ch. 7, Table VII-14 "BCR Values for Proposed Plan Controls," p. 42. SPD took the total estimated cost of the proposed plan for 2029-2032 ($332,421,000) and divided it by four, which is $83,105,250.

[833] SCE 2026 RAMP Ch. 7, Table VII-14 "BCR Values for Proposed Plan Controls," p. 42.

[834] SCE 2026 RAMP Ch. 7, Table I-1 "Summary of Pre- and Post- LORE and CORE Risk Scores," p. 2.

[835] Data Request SPD-SCE-2026RAMP-005, Question 53.

is an exemplar of a risk in which BCR are not an effective measure of the appropriateness of these types of programs. SCE has an obligation to ensure that it maintains a safe operating environment for its employees, and that these types of programs play a critical role in risk prevention."[836] SCE adds that, based on the benefits the controls provide maintaining the current risk levels which might increase in their absence, SCE "does not rely exclusively on BCR metrics when evaluating such programs and instead considers other factors, including but not limited to safety culture, regulatory expectations and requirements, and the critical role of these programs in preventing high-consequence outcomes. Discontinuing or scaling back such programs based solely on BCR results would not appear to be reasonable, as it may not be consistent with maintaining a safe operating environment and could increase exposure to unacceptable risk."[837]

Summary of Findings

SPD finds that:

1. SCE's effort is diminished somewhat by what appears to be a hasty effort marked by typos, stray language, and errors in various numeric tables, all of which introduced unnecessarily a measure of confusion to the process of reviewing SCE's submittal.
2. SCE's effort would have benefited from inclusion of a table serving a bridge function for this RAMP iteration's change of risk definition featuring like-for-like incident figures across its 2022 and 2026 RAMP efforts to facilitate the reviewer's understanding of whether 2022 trends hold constant.
3. SCE expects its proposed control measures will maintain risk at a constant level, but at increasing cost due to escalation of dollar value over time. Presentation of an alternative, no-build scenario could help illustrate the impact of SCE's proposed plan.

Recommendations to Address Findings

SPD recommends that SCE:

1. Take action to address Findings 1 through 3 in future RAMP filings and in further utility documents produced to support this RAMP and its companion GRC application.

[836] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 53.

[837] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 53.

5. Contractor Safety Risk

Risk Description

The Southern California Edison Company (SCE) defines contractor safety risk as incidents involving an SCE contractor or contractors leading to Serious Injury or Fatality (SIF) events or a Potential Serious Injury or Fatality (PSIF).[838, 839, 840]

SCE's 2026 Risk Assessment and Mitigation Phase (RAMP) application's risk definition for contractor safety risk represents a change from its 2022 approach, similar to revisions SCE made to its definition of employee safety risk. First, the utility preserves serious injury or death within the contractor risk definition to comply with guidance by its national trade association and explains that said trade group *narrowed* the scope of qualifying events to only those considered "life-altering."[841, 842] The second element of the risk definition revision is an *expanded* qualifying scope to also include those incidents that rise to a level considered a PSIF, or one that was averted, perhaps so close as to be a near miss.

SCE forecasts its risk value to increase moderately over the duration of the four-year General Rate Case (GRC) interval, from $84.23 million on January 1, 2029, to $92.2 million on December 31, 2032. Safety

[838] SCE 2026 RAMP, Chapter 8 "Contractor Safety," p. 4.

[839] SCE 2026 RAMP Ch. 8, Figure II-2 "Risk Bowtie for Contractor Safety," p. 7.

[840] SCE includes Days Away, Restricted, or Transferred (DART) in its definition for employee safety risk but not in its definition for contractor safety risk. This distinction results in SCE's not claiming financial consequences for this risk stemming from third-party workman's compensation claims costs, which are not borne by the utility.

[841] An example would be that whereas before a broken leg would have qualified as a SIF, under the new definition a qualifying leg injury would need to amount to loss of use of leg or worse.

[842] SCE explains its new definition of SIF thus: "In 2025, Southern California Edison adopted the revised SIF definition introduced by the [Edison Electric Institute]. This change marked a shift in how SIFs are classified and managed across the industry. The new definition more accurately defines the scope to focus exclusively on life-threatening injuries, life-altering injuries, and fatalities. This replaced the previous approach, which included a broader range of injuries—such as bone fractures that don't require surgery, tendon or ligament tears, and certain burns—that required medical treatment or restricted work," per SCE 2026 RAMP Ch. 8, p. 5.

Policy Division (SPD) asked for an explanation and received the responses noted in the footnotes.[843, 844] SPD found a straightforward answer within the utility's work papers: SCE expects the quantity of risk over the four-year interval to remain constant in the natural units of safety risk while SCE attributes the cost increase to an expected annual 2.3 percent escalation of the Value of Statistical Life monetization factor.[845] These risk figures are markedly higher than the values SCE estimates for employee safety risk, an issue SPD examines further in that chapter that in part is tied to fact that SCE, for the contractor safety risk, focuses solely on contractor workers assigned to work in the field on high-hazard assignments.

In response to a risk value approaching $100 million,[846] SCE proposes to spend about $5.6 million annually, and $22.25 million cumulatively for the four-year funding period 2029-2032.[847] Such spending ratios are the inverse of SCE's treatment for its employee safety risk. In that chapter, we see SCE spending on related risk-reduction efforts well in excess of the value of the risk. Additional key statistics that illuminate the utility's spending for this risk relative to the magnitude of the risk can be found within the Exposure section below. Note that for employee safety risk, SCE includes field-assigned workers of all stripes, including those who perform high-hazard tasks, as well as office-assigned staff, who account for the vast majority of the utility's employees.

Observations and Findings

SCE's annual spending of $5.6 million to address a risk having a mean annual value of $88.2 million[848] would appear to be an instance of underfunding risk reduction. However, in the context of other big

---

[843] SPD raised the question of why the risk value for contractor safety risk was expected to grow steadily despite SCE's expenditure of $22.5 million. Per SCE response to Data Request SPD-SCE-2026RAMP-005, Question 53, the utility's menu of risk controls within its proposed plan is "intended to maintain current risk levels and prevent increases in risk that could occur in their absence. Accordingly, a stable modeled likelihood should not be interpreted as an absence of program value, but rather as an indication that existing controls are sustaining risk at current levels."

[844] SPD raised the question a second time, rephrasing to ask why SCE expects the risk value for employee safety risk to grow steadily despite SCE's expenditure of $332.4 million. Per SCE response to Data Request SPD-SCE-2026RAMP-012, Question 1, the utility's risk model does not fully capture all factors that would demonstrate risk reduction and the BCR ratio is one of several metrics by which to gauge the effectiveness of a program's ability to control risk.

[845] SCE 2026 RAMP Ch. 8 work paper "Contractor Safety - Overall Residual Risk Calculations.xlsx" spreadsheet, tab "Contractor Table."

[846] SCE estimates a pre-mitigation risk score for contractor safety risk of about $84 million per SCE 2026 RAMP Ch. 8, Table I-1 "Summary of Proposed Plan Pre and Post LoRE and CoRE Risk Scores," p. 2.

[847] SPD calculation based on SCE 2026 RAMP Ch. 8, Table VI-15 "BCR Values for Proposed Controls," p. 35. According to that table, the full cycle spend for SCE's proposed plan is $22.25 million. SPD divides that by four for the annual spend, calculating $5.5625 million or about $5.6 million annual spend.

[848] SPD calculation of mean annual value of risk based on SCE 2026 RAMP Ch. 8, Table I-1 "Summary of Proposed Plan Pre and Post LoRE and CoRE Risk Scores," p. 2. SPD took the average of the proposed plan's pre-mitigation risk ($84,233,000) and post-mitigation risk ($92,254,000), which is $88,243,500 or about $88.2 million in risk.

California investor-owned utility (IOU) spending for this risk category, SCE's spending level is not so unusual. This subject is addressed further in the Benefit Cost Ratio (BCR) section below. As SPD discusses later in this assessment, SCE proposes no capital spending, with all costs incurred in the operations and maintenance (O&M) category, and SCE proposes no new mitigation measures as part of its proposed plan, with all risk reduction efforts tied to continuation of existing controls.

It's notable that the 2026 SCE RAMP marks the first time that SPD has evaluated this risk category within an SCE RAMP application. SCE introduced Contractor Safety as a standalone primary RAMP risk chapter within its 2022 Application, but SPD provided no assessment within its corresponding staff report. SCE had previously addressed the subject within its inaugural 2018 RAMP report, but the subject matter was just one within a broader risk chapter titled "Employee, Contractor & Public Safety." At the time, SPD noted the chapter risk within a corresponding 2019 staff report,[849] providing a limited one-page summary, noting the California Public Utilities Commission's (CPUC's or Commission's) jurisdiction over energy-utility safety. As such, the critical analysis offered here is the first for an SCE RAMP Contractor Safety risk chapter. This evaluation follows Sempra's 2025 RAMP and Pacific Gas and Electric Company's (PG&E's) 2024 RAMP, both of which received thorough written assessment and feedback on their respective Contractor Safety risk chapters. A review of other IOUs' RAMP reports can serve as early guidance for subsequent risk assessments. SPD's Risk Assessment unit, since 2024, has conducted thorough oversight of this risk topic.

Risk Bow Tie

SCE presents the following risk bow tie for contractor safety risk:

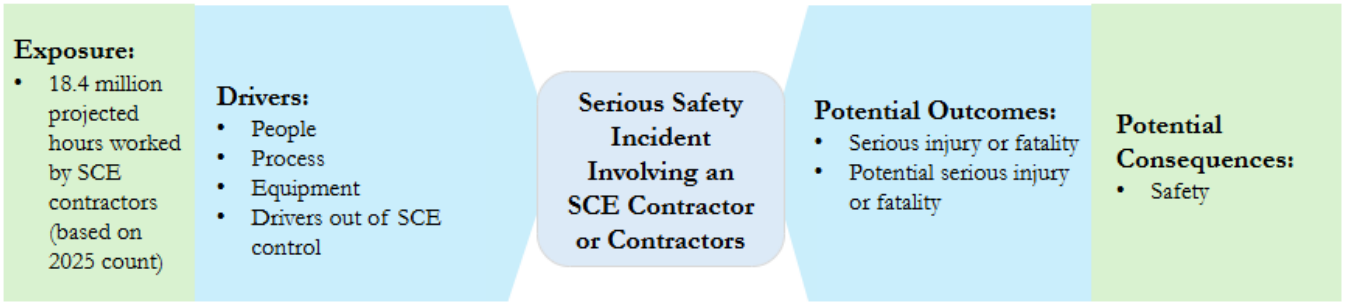


Figure 5-1. SPD Adaptation of SCE's Contractor Safety Risk Bow Tie[850]

Observations and Findings

SCE's risk bow tie diagram does not include many relevant and useful elements that one would like to see in a high-level risk dashboard profile. Key data points absent on the driver side include risk score, frequency,

[849] 2019 SPD Evaluation Report, p. 52, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=296255676, accessed July 21. 2026.

[850] SCE 2026 RAMP Ch. 8, Figure II-2 "Risk Bowtie for Contractor Safety," p. 7.

percent frequency, and percent of risk; while data points absent on the potential consequence side include consequence side include consequences of a risk event (CoRE), percent frequency, and percent of risk. Rather, the bow tie as submitted is too limited to satisfy the purpose of providing a useful all-in-one overview dashboard that encapsulates key characteristics that define the primary risks detailed in the chapter.

SPD expressed similar concerns last year in feedback provided on Sempra's 2025 RAMP application, which we expect the other utilities to have noted and acted on in following RAMPs. SPD cited earlier such criticism within SPD review of the Sempra 2021 RAMP, stating that the Sempra utilities "should clearly state or show which risk drivers or triggers (DTs) and potential consequences (PCs) are their priorities in the risk bow tie, using frequencies and/or rankings."[851]

Exposure

SCE ties exposure for contractor safety risk to the total number of hours worked by contractors. SCE estimates its contractors will annually work 18.4 million hours in the years covered by its 2026 RAMP.[852] By comparison, SCE annual contractor hours in 2025 amounted to 18.5 million hours, a decrease from 19.9 million hours in 2022.[853]

Observations and Findings

For analytic purposes, SPD estimates the number of SCE contractor workers[854] as the equivalent of 8,860 contract workers[855] based on 18.43 million hours worked annually[856] according to the number of full-time equivalent paid-hours, 2,080, in the typical U.S. work year.[857, 858] SPD acknowledges that this calculation is

---

[851] Safety Policy Division Staff Evaluation Report on SDG&E's and SoCalGas' Risk Assessment and Mitigation Phase (RAMP) Application Reports (A.) 21-05-011, (A.) 21-05-014 (Nov. 2021), p. 85 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/spd-evaluation-of-sdge-and-socalgas-2021-ramp-report_110521.pdf, accessed Oct. 6, 2026).

[852] SCE 2026 RAMP Ch. 8, Figure II-2 "Risk Bowtie for Contractor Safety," p. 7.

[853] SCE 2026 RAMP Ch. 8, p. 2.

[854] High-risk work only: SCE does not include other contract workers within the scope of its RAMP analysis.

[855] SPD calculation dividing 18.43 million work hours by 2,080 hours worked in a typical full-time job (at 40 hours a week) over a year.

[856] SCE 2026 RAMP Ch. 8, Figure II-2 "Risk Bowtie for Contractor Safety," p. 7.

[857] Given that many SCE contractor workers are assigned full time to SCE projects, the utility provides an annual hours count rather than a workforce count.

[858] My Hours, How Many Work Hours in a Year? Full Guide for 2026 (2026) (https://myhours.com/articles/how-many-work-hours-in-a-year, accessed Oct. 6, 2026).

based on an assumption of a boundary case that may not reflect the reality of the situation, since contractor workers may not actually work a typical full-time year for one utility.

In Table 5-1 below, SPD shows how for pre-mitigation risk its calculation of total likelihood of a risk event (LoRE), total consequence of a risk event (CoRE total),[859] and the risk total (LoRE times CoRE total), differ from SCE's calculations as presented in its Table VI-14 "Pre and Post LoRE, CoRE and Risk Scores for Proposed Plan." SPD observes that the appearance of miscalculations by SCE impeded its evaluation, given that the differences appeared to be larger than what SPD would expect from a rounding error. For example, SCE's Total Risk value (product of LoRE times CoRE) for Tranche 2 is about $7.85 million while SPD's calculation is about $6.39 million. SCE explained in data request responses that it calculated totals for LoRE and CoRE using source numbers that were calculated out many significant digits beyond what SCE presents in its table presenting LoRE and CoRE.[860] SCE should have clarified in its presentation of LoRE and CoRE in its RAMP that the numbers in the table were truncated versions of the numbers SCE used to calculate its totals.

[859] In the case of contractor safety risk, total CoRE is dictated entirely by the safety risk score: SCE does not attribute any reliability or financial risk to contractor safety risk.

[860] SCE response Data Request SPD-SCE-2026RAMP-005, Questions 52 and 54.

Table 5-1. SPD Breakdown of SCE Contractors by Tranche Category to Derive per-Contractor Risk ("Pre-Mitigation") ($000s)[861]

ID	Category of Contracted Work	LoRE per SCE	LoRE per SPD	CoRE Total per SCE	CoRE Total per SPD	Risk Total per SCE (LoRE x Total CoRE)	Risk Total per SPD (LoRE x Total CoRE)
T1	Transmission & Distribution	18	18	$3,004	$3,004	$54,887	$54,072*
T2	Vegetation Management	2	2	$3,193	$3,193	$7,853	$6,386*
T3	All other high-risk work	7	7	$2,908	$2,908	$21,493	$20,356*
	Total	**28**	**27***[862]			**$84,233**	**$80,814***[863]

*SPD number differs from SCE number.

In Table 5-2 below, SPD additionally compares the tranches by SCE's annual hours count per tranche and SPD's estimate of the number of contractors per tranche (based on the per-tranche hours), and the risk per equivalent worker.

[861] SCE 2026 RAMP Ch. 8, Table VI-14 "Pre and Post LoRE, CoRE and Risk Scores for Proposed Plan," p. 35.

[862] The calculation of 18 + 2 + 7 totaling to 28 is due to "a significant digit rounding issue," per SCE response to SCE response to Data Request SPD-SCE-2026RAMP-005, Question 54.

[863] In evaluating SCE's Employee Safety chapter, SPD also calculated different a total CoRE using the input numbers presented by SCE from the total CoRE presented by SCE. SPD's different outcome is also due to rounding issues, per SCE response Data Request SPD-SCE-2026RAMP-005, Question 52.

Table 5-2. SPD Breakdown of Risk per SCE Contractor by Tranche Category ("Pre-Mitigation") ($000s)[864]

ID	Category of Contracted Work	Risk Total per SPD (LoRE x Total CoRE)	SCE Contractor Hours Count (2025)	Percent of Total Hours	SPD Estimated Contractor Count[865]	SPD Estimated Risk per Contractor
T1	Transmission & Distribution	$54,072*	7,188,302	39%	3,456	$15.65
T2	Vegetation Management	$6,386*	7,152,481	39%	3,439	$1.86
T3	All other high-risk work	$20,356*	4,088,766	22%	1,966	$10.35
	Total	**$80,814***	**18,429,549**	**100%**	**8,860**	**$27.86**

*SPD number differs from SCE number (see above for SCE numbers).

The table above builds upon the base assumption that SCE has about 8,860 high-risk-work contractors based on SCE's estimate of 18.43 million annual contractor hours worked.

Analysis of Spending and Risk

SPD calculated the following based on the calculations in Table 5-2 and SCE's proposed annual spend of $5.6 million[866] and monetized mean annual risk value of $88.2 million:[867]

- Per-hour planned annual spending on contractor safety: $0.29
- Per-hour value of contractor safety risk: $4.79
- Per-worker planned annual spending: $604.97
- Per-worker annual value of contractor safety risk: $9,957.11

[864] SPD calculations based on SCE 2026 RAMP Ch. 8, Table II-8 "SCE's Contractor Safety, Annual Hours Worked, and Pre-and-Post Risk Score," p. 13.

[865] Based on the estimate of 2,080 hours worked per year, per My Hours, How Many Work Hours in a Year? Full Guide for 2026 (2026) (https://myhours.com/articles/how-many-work-hours-in-a-year, accessed Oct. 6, 2026).

[866] SPD calculation based on SCE 2026 RAMP Ch. 8, Table VI-15 "BCR Values for Proposed Controls," p. 35. According to that table, the full cycle spend for SCE's proposed plan is $22.25 million. SPD divides that by four for the annual spend, calculating $5.5625 million or about $5.6 million annual spend.

[867] SPD calculation of mean annual value of risk based on SCE 2026 RAMP Ch. 8, Table I-1 "Summary of Proposed Plan Pre and Post LoRE and CoRE Risk Scores," p. 2. SPD took the average of the proposed plan's pre-mitigation risk ($84,233,000) and post-mitigation risk ($92,254,000), which is $88,243,500 or about $88.2 million.

Additionally, for this risk, based on SCE's estimate of 31.4 qualifying incidents per year,[868] SPD calculated a resulting average annual risk value per incident of $2.81 million, and a corresponding spend per incident of $179,299.

SPD observes that, in comparison with the employee safety risk chapter, for contractor safety risk, risk values and costs are sharply higher while spending levels for risk reduction are dramatically lower. Such a condition, with possibly higher human welfare jeopardy among two classes of workers, and with possibly inequitable responses, would seem to raise ethical concerns. SPD observes that energy utilities may respond to such criticism by noting that their spending levels do not reflect efforts by the vendor to keep contract workers safe and that the utility is not privy to such arrangements by nature of third-party vendor corporate autonomy, and labor- and contract-law.[869] SPD observes that SCE and other utilities could provide greater transparency regarding their risk portfolios to substantiate their reassurances of safety adequacy given the sizable risk that contractor safety represents and the relatively small amount that SCE and other utilities spend to address it. The Commission has rejected past arguments put forward by SCE that the utility is not responsible for the failure of its contractors to properly perform work and has clarified that the utility and peer entities "cannot escape this responsibility by delegating it to independent contractors."[870]

SCE's treatment of exposure has implications for its risk tranches, the subject of our next discussion. Overall, as presented in the BCR Section, the BCR of the proposed plan indicates the benefits exceed the costs, at 1.69.

Tranches

SCE departs from the default quintile tranching methodology for this risk.

SCE defines three tranches for this risk based on categories of contractor work:[871]

- Transmission & Distribution (T1)
- Vegetation Management (VM) (T2)
- All other high-risk work (T3)

[868] SCE 2026 RAMP Ch. 8, Table II-3 "Annualized RAMP Driver Frequency, p. 8.

[869] SCE response to Data Request SPD-SCE-2026RAMP-012, Question 10.

[870] CPUC, Opinion Finding Violations and Imposing Sanctions (Decision 04-04-065 of April 22, 2004), p. 34 (https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/36914.PDF, accessed Oct. 8, 2026).

[871] SCE 2026 RAMP Ch. 8, p. 12.

Observations and Findings

SPD observes that Table 5-2 above shows a situation where the highest risk tranche, Transmission and Distribution (T1), accounts for nearly twice the total combined risk of the other two tranches, Vegetation Management (T2) and all other high-risk work (T3).

SPD further observes that the per worker risk for SCE's most high-hazard contractor tranche, approaching $16 million per worker risk, is lower than for high-risk in-house employees, having a per worker risk of nearly $22 million.[872] SPD observes that it appears that SCE does not rely on contractors to perform exclusively the most dangerous utility work, at least by one measure. [873, 874]

Risk Reporting Units (RRUs)

SCE did not define RRUs for this risk.

Observations and Findings

The RDF Phase 4 Decision requires that utilities define an RRU for each electric or gas operations mitigation, exempting the PSPS and protective equipment device settings mitigation categories.[875, 876, 877]

SPD observes that contractor risk mitigation is not specific to electric operations risk mitigation and as such is not subject to the RRU requirement.

---

[872] See also in this evaluation report Chapter 4 "Employee Safety Risk," Table 4-2. "SPD Breakdown of Risk Tranches to Derive Per-Employee Risk."

[873] That measure, standalone per-worker risk value, can be more fully illuminated in the context of annual hours worked, where contracted hours worked total a multiple of in-house SCE employee field transmission and distribution activities.

[874] This is not to downplay the significance of SCE's contractor field-assigned high-hazard workforce exposure with 18.43 million annual hours worked, compared with all SCE in-house employees who account for 28.2 million employee annual hours worked. Another metric: consider that SCE's contractor workforce is responsible for 100 percent of all SCE high-hazard tree trimming, tree removal, and other vegetation management activities, per SCE response to Data Request SPD-SCE-2026RAMP-012, Question 3(a).

[875] D.25-08-032, Appendix A, Definitions, p. A-7.

[876] D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[877] "The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following: 1. Public Safety Power Shutoffs; 2. Protective Equipment Device Settings; 3. Mitigation and Control Programs that do not meet the following thresholds: a. For PG&E and SCE, $10 million…" from D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

Risk Drivers

In its risk bow tie, SCE presents four potential leading indicators for this risk, or drivers:[878]

- People (D1)
- Process (D2)
- Equipment (D3)
- Drivers out of SCE control (D4)

Table 5-3. SCE Risk Driver Characteristics at a Glance[879]

ID	Driver	Total (2021-2025)	Annual Frequency	Percent of Driver Frequency
D1	People	78	15.6	49.7%
D2	Process	74	14.8	47.1%
D3	Equipment	3	0.6	1.9%
D4	Drivers out of SCE control	2	0.4	1.3%
	Total	**157**	**31.4**	**100%**

Observations and Findings

SPD notes that the "people" and "process" drivers (D1 and D2) combined account for more than 96 percent of total risk frequency,[880] as shown above in Table 5-3. SCE puts forward driver frequency data covering years 2021-2025 that, when compared with the prior five-year period of 2017-2021, do not demonstrate a clear definitive trend that can be explained as an increase or decrease.[881]

SCE reports that, for several reasons, its safety incident data integrity for this risk sector trails that for in-house employees, which itself, for the industry, generally trails for safety events involving assets only.

---

[878] SCE 2026 RAMP Ch. 8, Figure II-2 "Risk Bowtie for Contractor Safety," p. 7.

[879] SCE 2026 RAMP Ch. 8, Table II-3 "Annualized RAMP Driver Frequency," p. 8.

[880] SCE 2026 RAMP Ch. 8, Table II-3 "Annualized RAMP Driver Frequency," p. 8.

[881] Application of Southern California Edison Company (U 338-E) Regarding 2022 Risk Assessment Mitigation Phase (RAMP) (May 2022) (SCE 2022 RAMP) Chapter 10 "Contractor Safety," Table II-4 "Historical RAMP Driver Frequency," p. 8 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M476/K640/476640383.PDF, accessed Oct. 7, 2026).

Consequences

As shown earlier, SCE identified two potential consequences in its risk bow tie diagram:

- Serious Injury or Fatality (SIF)
- Potential Serious Injury or Fatality (PSIF)

As noted earlier, in its 2022 RAMP SCE included only activities leading to "a serious safety incident" in its contractor risk definition882 while in its 2026 RAMP SCE expands the scope to include activities leading to "a serious or potentially serious safety incident,"883 following trade association guidance.884

Observations and Findings

SPD has no observations or findings on consequences.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[885]

For this risk, SCE identified two controls,[886] both included in SCE's proposed plan and alternative plans, and two mitigations associated with its two alternative plans.[887]

SCE's two controls for contractor safety risk, both continued from the prior RAMP, are:[888]

---

[882] SCE 2022 RAMP Ch. 10, Table II-2 "Scope of Contractor Safety Risk," p. 5.

[883] SCE 2026 RAMP Ch. 8, Table II-2 "Contractor Safety Chapter Scope," p. 6.

[884] SCE explains its new definition of SIF thus: "In 2025, Southern California Edison adopted the revised SIF definition introduced by the [Edison Electric Institute]. This change marked a shift in how SIFs are classified and managed across the industry. The new definition more accurately defines the scope to focus exclusively on life-threatening injuries, life-altering injuries, and fatalities. This replaced the previous approach, which included a broader range of injuries—such as bone fractures that don't require surgery, tendon or ligament tears, and certain burns—that required medical treatment or restricted work," per SCE 2026 RAMP Ch. 8, p. 5.

[885] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[886] SCE 2026 RAMP Ch. 8, Table III-9 "Inventory of Contractor Safety Controls," p. 14.

[887] SCE 2026 RAMP Ch. 8, Table IV-11 "Inventory of Contractor Safety Mitigations," p. 24.

[888] SCE 2026 RAMP Ch. 8, pp. 15-23.

- Pre-Qualification and On-Boarding (C1): Pre-hire contractor screening and safety record vetting, new-hire orientation and training; monitoring of and probationary status for potentially unsafe vendors
- Oversight, Performance Management and Culture Development (C2): Field observation and feedback on worker conduct alignment with safety goals and expectations; targeted and prioritized coaching and quality control auditing for vendors whose high-hazard activities render them most vulnerable to a safety lapse.

The two mitigations SCE proposes as elements in its alternative plans are:

- Training of Contractors (M1 or A1),[889] proposed as part of the first alternative plan: A "joint leadership council and development between SCE and contractors focused on SIF prevention priorities."[890]
- Independent Third-Party Safety Prequalification (M2 or A2),[891] proposed as part of the second alternative plan: A jointly created and funded "independent third-party administrator (TPA) for safety pre-qualification of contractors performing high-risk work."[892]

SPD discusses these further under Alternatives Analysis.

SCE estimates a full cycle cost for its proposed plan for contractor safety risk mitigation at about $22.25 million, which SPD calculates is about $5.6 million annually,[893] with the entire spend assigned to O&M; none assigned to capital improvements.[894] This is an increase over the amount SCE proposed to spend on contractor safety in its 2022 RAMP, about $4.54 million per year, for a fairly similar approach to risk reduction across three controls.[895, 896]

---

[889] The ID of the first mitigation is "M1" per SCE 2026 RAMP Ch. 8, Table IV-11 "Inventory of Contractor Safety Mitigations," p. 24; it is "A1" per SCE 2026 RAMP Ch. 8, Table VII-17 "BCR Values for Alternative Plan #1 Controls," p. 38.

[890] SCE 2026 RAMP Ch. 8, p. 24.

[891] The ID of the second mitigation is "M2" per SCE 2026 RAMP, Table IV-11 "Inventory of Contractor Safety Mitigations," p. 24; it is "A2" per SCE 2026 RAMP Ch. 8, Table VII-19 "BCR Values for Alternative Plan #2 Controls," p. 40.

[892] SCE 2026 RAMP Ch. 8, pp. 25-27.

[893] SPD calculation based on SCE 2026 RAMP Ch. 8, Table VI-15 "BCR Values for Proposed Controls," p. 35. According to that table, the full cycle spend for SCE's proposed plan is $22.25 million. SPD divides that by four for the annual spend, calculating $5.5625 million or about $5.6 million annual spend.

[894] SCE 2026 RAMP Ch. 8, Table VI-15 "BCR Values for Proposed Controls," p. 35.

[895] SCE 2022 RAMP Ch. 10, Table VI-10 "Proposed Plan (Total Costs in Millions and 2025 Risk Spend Efficiencies)," p. 30.

[896] The third control SCE proposed for this risk in its 2022 RAMP was Incident Management and Learning, now included as a foundational activity in SCE's 2026 RAMP per SCE 2026 RAMP Ch. 8, pp. 29-32.

Observations and Findings

SPD observes that SCE's controls, as described, appear to be well considered and a case of attempting to optimize effectiveness in the face of constrained spending. Yet, the spending here (2026 RAMP, $5.6 million annually by SPD calculation) relative to employee safety (2026 RAMP, $83.1 million annually by SPD calculation) raises the question of whether SCE could do more to address contractor safety risk.

The risk reduction program that SCE describes emphasizes high standards for vendors and taking steps to verify that those standards are upheld. SCE's approach integrates human-driven programs such as field site observations paired with real-time coaching and feedback, with program optimization tools such as scorecards and screening and incident tracking to monitor safety performance.

SCE's controls appear to allow for safety incidents and observed poor form to become teachable moments. SCE's approach to risk reduction appears to be in line with contemporary industry standards. The utility's account of its control plan could be improved by way of clearer assurances that contract workers have some measure of immunity from discipline in the course of coming forward to declare a mistake, violation of safety protocol, or actual incident. That is to say, it would be reassuring to hear that SCE and its vendors are actively championing practices that encourage parties involved in procedural lapses or safety incidents to make a no-fault report, and have the experience added to the record of tracked safety data, and perhaps have those involved, as well as others, learn from the experience. These job characteristics—promoting a healthy culture of open communication while harnessing value within teachable, if unflattering, moments—hold value and are also in line with contemporary industry standards.

The absence of mitigation measures from SCE's proposed plan means that the utility's controls are doing the full job of risk reduction for contractor safety. SCE's roster of controls are one and the same as the utility's proposed plan for risk reduction. SCE's absence of mitigation measures is notable, and the utility is encouraged to consider and weigh new measures that may hold potential to make workers safer. At minimum, the utility should explain and justify the absence of new measures in future RAMP filings.

Additionally, SPD observes that SCE's proposed spending level could be considered somewhat in the mid-range of what is typical for a large California energy utility. Sempra's 2025 RAMP showed San Diego Gas & Electric Company (SDG&E) proposing to spend (per SPD calculation) about $6.23 million per year on contractor safety and Southern California Gas Company (SoCal Gas) proposing to spend $1.5 million per

year on contractor safety.[897] In another example, PG&E put forward a contractor safety risk reduction plan in its 2024 RAMP that proposed to spend $3 million annually (per SPD calculation).[898]

Alternatives Analysis

SCE presents two alternatives. Each introduces a mitigation, as noted above.

SCE proposes Training of Contractors (M1 or A1)[899] as part of its first alternative plan. This would entail a "joint leadership council and development between SCE and contractors focused on SIF prevention priorities."[900] This mitigation would help navigate existing barriers, including legal requirements, to introduce new safety trainings that, among other things, would bring to light how an organization or environment presents inherent safety hazards with inherent potential for safety incidents where the fault is not necessarily attributable to those involved. SCE forecasts the incremental cost of M1/A1 at $8.04 million in O&M over four years with a BCR of 0.32,[901] which, when combined with the initial two controls from the proposed plan, lowers plan BCR from 1.69 to 1.32.

SCE proposes Independent Third-Party Safety Prequalification (M2 or A2)[902] as part of its second alternative plan. This would entail a jointly created and funded "independent third-party administrator (TPA) for safety pre-qualification of contractors performing high-risk work."[903] SCE reports that it would work with other California IOUs (subject to CPUC oversight) to set up and fund the TPA, which would be a non-profit, taking the place of for-profit TPAs (ISNetworld, Avetta, etc.). SCE notes that this approach could reduce the costs of contracting and provide incentive for the IOUs to invest in better tools that

---

[897] Sempra 2025 RAMP Application: SDG&E 2025 Risk Assessment Mitigation Phase, Chapter SDG&E-Risk-7 "Contractor Safety," Table 6 "Contractor Safety Risk Control and Mitigation Plan Recorded and Forecast Costs Summary," p. 18; Chapter SCG-Risk-6 "Contractor Safety," Table 6 "Contractor Safety Risk Control and Mitigation Plan Recorded and Forecast Costs Summary)," p. 18 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/2025-sempra-ramp-application.pdf, accessed Oct. 7, 2026).

[898] Pacific Gas and Electric Company 2024 Risk Assessment and Mitigation Phase Report, Chapter 1 Risk Assessment and Mitigation Strategy: Contractor Safety Incident, Table 1-10 "Controls Cost Estimates, Risk Reduction, and CBR 2027-2030," p. 1-29 (PDF p. 773); Table 1-11 "Mitigation Cost Estimates, Risk Reduction, CBR, and Factors Affecting Selection 2027-2030," p. 1-31 (PDF p. 775) (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf, accessed Oct. 7, 2026).

[899] The ID of the first mitigation is "M1" per SCE 2026 RAMP Ch. 8, Table IV-11 "Inventory of Contractor Safety Mitigations," p. 24; it is "A1" per SCE 2026 RAMP Ch. 8, Table VII-17 "BCR Values for Alternative Plan #1 Controls," p. 38.

[900] SCE 2026 RAMP Ch. 8, p. 24.

[901] SCE 2026 RAMP Chapter 8, Table VII-17.

[902] The ID of the second mitigation is "M2" per SCE 2026 RAMP, Table IV-11 "Inventory of Contractor Safety Mitigations," p. 24; it is "A2" per SCE 2026 RAMP Ch. 8, Table VII-19 "BCR Values for Alternative Plan #2 Controls," p. 40.

[903] SCE 2026 RAMP Ch. 8, pp. 25-27.

reduce serious injury risks. [904, 905] SCE forecasts the incremental cost of M2/A2 at $3.81 million in O&M over the four years with a BCR of 1.00,[906] which, when combined with the initial two controls from the proposed plan, does not change the proposed plan BCR.

SCE rejects both alternatives. While SCE states that it is "actively exploring" the Training of Contractors mitigation approach, SCE rejects it because "it raises key unresolved questions including overall cost, logistical feasibility, and workforce classification/compliance considerations," making it "difficult to justify the level of investment required."[907] Regarding the Independent Third-Party Safety Prequalification mitigation, SCE points to the fact that the existing use of TPAs is subject to provisions specified by Section 2.2 of CPUC Decision 17-06-028, adding "CPUC guidance would be needed to determine if establishing an independent entity to address this requirement is permissible and prudent."[908]

Observations and Findings

SPD observes that, overall, SCE's alternative plans fall short in that neither is viable from the standpoint of being implementable near- to mid-term. Also, instead of delivering two comprehensive and thoughtful plan alternatives, each consisting of multiple measures, the utility merely offers two incremental mitigations along with continuation of existing controls and calls each an alternative plan.

Both mitigations associated with the alternative plans appear to hold promise that would address existing conditions that appear suboptimal. Both mitigations come at a relatively modest cost of roughly $1 million or $2 million per year. But SCE reports numerous arduous regulatory, legal, and organizational hurdles that it must navigate over the course of some years in order to bring either to fruition.

Both mitigations, floated by SCE as viable at some future unspecified date, appear to hold potential to partially address some of the deficiencies within the utility's approach to contractor safety risk. As such, the utility is encouraged to further develop its proposals and make progress on navigating associated barriers to implementation.

SPD also finds that an additional helpful alternative scenario in cases like this one, where the control and mitigation plan proposes to maintain risk at a constant level in natural units, would be to present a 'no-build' scenario: an analysis of the increase in risk in the absence of the proposed plan. Such an alternative presentation would help illustrate the value of the plan.

---

[904] SCE 2026 RAMP Ch. 8, pp. 25-27.

[905] SCE 2026 RAMP Ch. 8, pp. 40-41.

[906] SCE 2026 RAMP Chapter 8, Table VII-19.

[907] SCE 2026 RAMP Ch. 8, p. 39.

[908] SCE 2026 RAMP Ch. 8, p. 41.

BCR Calculations

SCE calculates BCR values for its two controls and two mitigations for contractor safety risk. SCE presents all BCRs, as required, under three discount rate scenarios: a weighted-average cost of capital (WACC) rate, a societal rate, and a hybrid rate.

Table 5-4 presents SCE's projected BCRs for the two controls in SCE's proposed plan for mitigating contractor safety risk.

Table 5-4. BCR Values for Proposed Plan Controls[909]

ID	Control	BCR (Societal)	BCR (WACC)	BCR (Hybrid)
C1	Pre-Qualification and Onboarding	2.00	2.00	2.16
C2	Oversight, Performance Management and Culture Development	1.56	1.56	1.68
	Total	**1.69**	**1.69**	**1.83**

Observations and Findings

SPD observes that SCE's BCRs for these controls are above 1.0, indicating that the forecasted benefits exceed the costs.

Summary of Findings

SPD finds that:

1. SCE does not include all contractors in its employ for RAMP purposes but speaks to a smaller, select subgroup.
2. SCE's spending for contractor safety risk is a fraction of that for employee safety risk despite the utility's numbers showing a much higher risk score for contractor safety risk.
3. Vendor spending for contractor safety risk, presumed to fill the gap in utility spending, is opaque and SCE could do more to improve and facilitate reasonable transparency.
4. The two alternative plans that SCE floats in this RAMP risk chapter are not of a level of development and maturity that can yet be considered viable, although they appear to hold potential to improve the safety of contractor workers at some future date some years out.

[909] SCE 2026 RAMP Ch. 8, Table VI-15 "BCR Values for Proposed Controls," p. 35.

5. SCE presents alternative plans that are not serious proposals from the standpoint that they are not viable or ones that SCE has any intention of seriously considering for implementation within the timeframe addressed by its RAMP proposal.
6. There is a presumption, advanced by SCE, that the bulk of the responsibility for keeping contractors safe is, and should be, borne by the vendors who are the direct employers of the contractors. Yet, SCE provides limited and unquantified information in this regard.
7. In response to questions of why risk levels continue to grow for contractor safety despite the investment proposed by SCE, SCE asserts a counterfactual hypothetical in which risk levels would accelerate still further and faster. Yet, the utility's argument could have been articulated more persuasively had SCE provided an additional, third, plan alternative describing and quantifying a no-build scenario; that is, a hypothetical alternative where none of the controls is applied (or "built") to show the change in risk should the controls not be in place.

Recommendations to Address Findings

SPD recommends that SCE:

1. Within forthcoming future RAMP efforts, disclose and quantify the full ranks of contractor workers in its employ and articulate how the subset chosen for RAMP analysis compares relative to size of the sector overall. In tandem, SCE should justify and explain its rationale for excluding some categories of contract workers from RAMP analysis.
2. Take actions internally and with its peer utilities to better articulate and explain how contractor workers in the field performing high hazard work are afforded reasonable parity with utility in-house employees in considering all practicable risk reduction options to ensure their safety.
3. In future RAMP iterations, make some declaration as to how utility dollars programmed in pursuit of contractor safety are or are not matched and supplemented by vendor commitments, and whether such vendor spending commitments are voluntary or obligatory by way of utility hiring rules, to reduce risk to utility contractor workers.
4. Further develop its proposals as outlined in the two for-discussion-purposes plan alternatives featured in this RAMP risk chapter and make progress on navigating associated barriers to implementation so as to enable program introduction by way of the 2030 RAMP.
5. For future RAMP reports, cease the practice of relying on and describing plan alternatives that are not serious proposals from the standpoint that they are not viable or ones that SCE has any intention of seriously considering for implementation within the timeframe addressed by its RAMP proposal.
6. Provide quantified information to support the utility's assertion that the bulk of the financial and contractual responsibility for keeping contractor workers safe is, and should be, borne by the vendors who are their direct employers.
7. Provide a third no-build plan that substantiates the optimization claims made within SCE's counterfactual hypothetical rationalization of steady to increased spending for this risk being met with yet a higher risk burden. Such a no-build alternative would, among other benefits, hold value

for its ability to serve as a baseline metric to better support and more clearly substantiate SCE assurances that acceptance of rising levels of risk in the face of steady or rising spending levels on risk-reduction is indeed an optimal condition.

8. In future RAMP filings, perform a final quality check on the numeric values presented.

6. Public Safety Risk Not Attributable to Asset Failure

Risk Description

In its 2026 Risk Assessment and Mitigation Phase (RAMP) application, the Southern California Edison Company (SCE) introduces a new RAMP risk: "public safety risk not attributable to asset failure" (public safety risk), which captures incidental public interactions with intact electrical equipment.[910] In SCE's ranking of enterprise risks by total risk value, including safety, reliability, and financial risk, this risk comes third after first-place wildfire and Public Safety Power Shutoff (PSPS) risk and second-place overhead equipment failure risk.[911] This chapter deals with the risks of third-party dig-ins,[912] members of the public interacting with overhead electrical lines, and vehicles including aircraft hitting infrastructure. All these risks involve the possibility of human contact with medium or high voltage electrical conductors that can result in serious injuries and fatalities.

SCE reports that there are on average about 2,600 annual instances of members of the public coming into contact with its intact overhead and underground electrical equipment.[913] By far the most frequent kind of public safety risk event among these instances is third-party vehicle contact (also called "vehicle hit").[914] A vehicle hit occurs when a motorized ground vehicle comes into contact with intact SCE electrical infrastructure.[915] SCE estimates about 2,300 annual such events, while the other kinds of public interaction with intact infrastructure are far less frequent, with estimated annual frequencies of 260 for dig-ins, 13 for elevated worker contact, and 0.5 for aircraft strikes.[916]

---

[910] SCE 2026 RAMP, Chapter 9 "Public Safety Risk Not Attributable to Asset Failure," p. 1; Chapter 1 "Overview," p. 2.

[911] SCE's Pre-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop Presentation, Dec. 18, 2025, slide 14 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-pre-filing-ramp-workshop-slides_dec-2025.pdf, accessed July 10, 2026).

[912] SCE defines a third-party dig-in as an event where excavation activities conducted by a member of the public coming into contact with underground electrical facilities, per SCE 2026 RAMP, Ch. 9, p. 10.

[913] SCE states "this count includes Public Safety Risk Not Attributable to Asset Failure events that are modeled quantitatively within this chapter. The count excludes third-party vandalism incidents and third-party vehicle hit incidents outside of the at-risk population identified for mitigation." Per SCE RAMP, Ch. 9, p. 1, footnote 3.

[914] SCE in this chapter calls this risk variously vehicle contact, vehicle hit, vehicle hit pole, and vehicle hit poles and structures. These all appear to refer to the same category of risk event.

[915] SCE 2026 RAMP, Ch. 9, p. 10.

[916] SPD calculates the estimated average annual frequency for third-party vehicle contact by totaling the pre-mitigation LoRE for the two tranches described by SCE as "3rd Party Vehicle Hit" in two tranches, A and B, respectively 56 and 2,282; these numbers and the other frequency estimates are per SCE 2026 RAMP Ch. 9, Table VI-8 "Proposed Plan Pre- and Post-Mitigation LoRE, CoRE and Risk Scores," p. 31.

Observations and Findings

Safety Policy Division (SPD) has no observations or findings on the risk description.

Risk Bow Tie

SCE presents the following risk bow tie for public safety risk:

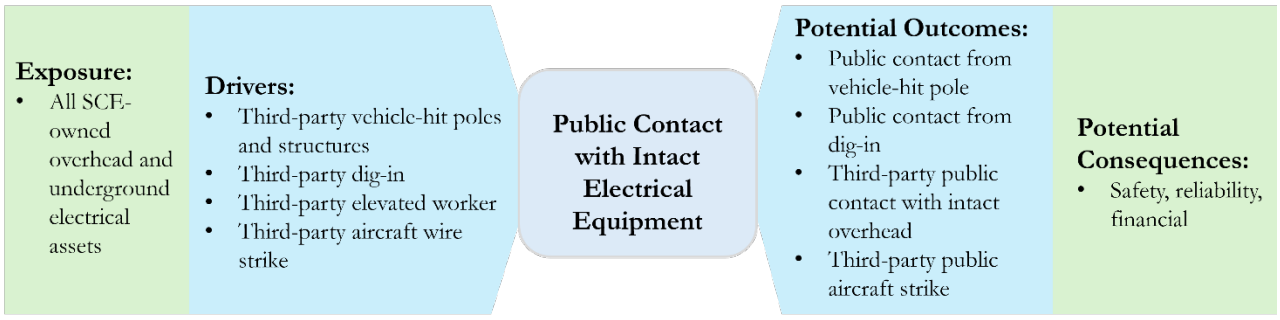


Figure 6-1. SPD Adaptation of SCE Public Safety Risk Bow Tie.[917]

Observations and Findings

SPD has no observations or findings on SCE's public safety risk bow tie.

Exposure

SCE defines its public safety risk exposure to include all SCE-owned overhead and underground electrical assets, including all distribution and transmission electrical infrastructure under SCE's control in the utility's service territory.[918] SCE suggests that it could alternatively be defined as "members of the public who come into proximity with SCE's electrical assets."[919] Excluded from the exposure definition for this risk is public contact with electrical equipment within the property lines of SCE facilities (e.g., substations). For the most prevalent risk driver, vehicle hit, SCE limits the exposure definition to a subset of poles, streetlights, and pad-mounted equipment that SCE has identified as having elevated vehicle-hit risk based on internal data and modeling.[920] The other risk drivers' exposure definitions are underground electrical assets for dig-in, overhead distribution conductors for elevated worker, and overhead lines and conductors for aircraft wire strike.

---

[917] SCE 2026 RAMP Ch. 9, Figure II-1 "Risk Bowtie for Public Safety Risk not Attributable to Asset Failure," p. 8.

[918] SCE 2026 RAMP Ch. 9, p. 8.

[919] SCE 2026 RAMP Ch. 9, p. 8.

[920] SCE 2026 RAMP Ch. 9, p. 9.

Observations and Findings

SPD has no observations or findings on SCE's statement of exposure to this risk.

Tranches

SCE departs from the default quintile tranching methodology for this risk.[921]

SCE uses two different tranching methods in this chapter.[922] For vehicle hit risk,[923] SCE divides the exposed assets into two tranches. One vehicle hit risk tranche includes structures hit by vehicles three or more times and the other tranche, including roughly 100,000 structures, includes structures at elevated risk of being hit.

SCE uses one system level tranche for each other risk (dig-in, elevated worker, aircraft wire strike).

Observations and Findings

SPD observes that, for the vehicle hit risk subcategory, SCE deviates from the Risk-Based Decision-Making Framework (RDF) Phase 4 Decision requirement that, if the utility wants to use a tranching method other than the quintile method, the utility must submit its proposed approach "no later than 45 days before their first pre-RAMP workshop," which in SCE's case took place on December 18, 2025.[924] Per that requirement, SCE submitted a 2026 RAMP Tranching White Paper on November 3, 2025, which indicated that SCE intended to use the quintile method of tranching for the vehicle hit risk subcategory.[925] In SCE's updated version of that paper submitted on May 27, 2026, SCE indicates that it changed its approach, instead applying "a two-tranche approach" to this risk.[926] SCE did not follow the RDF requirement to provide advance notice of its departure from the quintile risk tranching approach for this important subcategory of public safety risk. This prevented stakeholders from being able to comment on SCE's vehicle hit tranching method before SCE filed its RAMP application.

---

[921] SCE 2026 RAMP "Chapter 2 Risk Model and BRC [sic] Methodology Tranching Whitepaper," under "Public Contact with Intact Energized Equipment," p. WP-2 and original document pp. 14-18/pp. WP-18-WP-22.

[922] SCE RAMP-9 Public Safety Risk Not Attributable To Asset Failure, pp. 14, 15.

[923] As noted above, SCE in this chapter calls this risk variously vehicle contact, vehicle hit, vehicle hit pole, and vehicle hit poles and structures. These all appear to refer to the same category of risk event.

[924] D.25-08-032, Appendix A, Row 14, pp. A-15-A-16.

[925] Under the category "Public Contact with Intact Energized Equipment," SCE indicated in its November 3, 2025, submission its intent to use the quintile tranching method for the "Vehicle Hit Pole sub-risk," per "SCE 2026 RAMP Tranching White Paper," p. 14 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-ramp-tranching-white-paper_nov-2025.pdf, accessed Aug. 3, 2026).

[926] "Chapter 2 Risk Model and BRC [sic] Methodology Tranching Whitepaper," p. WP-2. SCE describes its two-tier tranche system for this risk in its 2026 RAMP in Ch. 9 on pp. 14-15.

Risk Reporting Units (RRUs)

SCE did not define RRUs for this risk.

Observations and Findings

The RDF Phase 4 Decision requires that utilities define an RRU for each electric or gas operations mitigation, with some exemptions.[927, 928] Risk mitigation categories that the Phase 4 Decision exempted from needing RRUs to be defined are PSPS and protective equipment device settings.[929] Other than these, the Phase 4 Decision required SCE to define RRUs for mitigation programs costing $10 million or more. For the purposes of this report, SPD is interpreting the $10 million threshold to pertain to the cost of the mitigation program over the course of the four-year RAMP cycle.[930]

In its proposed plan, SCE reports two programs that exceed the $10 million threshold and do not fall under the categories of PSPS or protective equipment device settings:[931]

- Public Outreach – Intact Contact (C1), with a full cycle cost of $14.482 million.
- Locate and Mark – Distribution (C2), with a full cycle cost of $147.768 million.

While the Public Outreach – Intact Contact control is not specific to electric operations, the Locate and Mark – Distribution control is.

However, SCE does not provide RRUs or an explanation of why it does not provide RRUs for the Locate and Mark – Distribution control.

Risk Drivers

In its risk bow tie, SCE presents four potential leading indicators for this risk, or drivers. These drivers are third-party vehicle hit,[932] third-party dig-ins, third-party elevated worker contact, and third-party aircraft wire

---

927 D.25-08-032, Appendix A, Definitions, p. A-7.

928 D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

929 "The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following: 1. Public Safety Power Shutoffs; 2. Protective Equipment Device Settings; 3. Mitigation and Control Programs that do not meet the following thresholds: a. For PG&E and SCE, $10 million…" from D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

930 D.25-08-032, p. 67 ("establishing a cost threshold for mitigation and control programs based on the same thresholds found in the Phase 1 Decision…"), which in turn points to the RDF Phase 1 Decision, D.21-11-009, p. 141, where the cost threshold is described as "the aggregate cost over the upcoming GRC funding period."

931 SCE 2026 RAMP Ch. 9, Table VI-7 "Proposed Plan (Total Costs and Benefit-Cost Ratios (BCRs))," p. 30.

932 SCE calls this driver "Third-Party Vehicle Hit Poles and Structures" in its risk bow tie. As noted above, SCE uses other terms elsewhere, including vehicle contact, vehicle hit, and vehicle hit pole.

strike. SCE notes that, while this is not a comprehensive list of potential risk drivers, these four drivers represent "the known public safety risks for which SCE has collected meaningful data and has available mitigations."[933]

Vehicle hit includes cars and trucks impacting poles, transmission structures, streetlights, and pad-mounted equipment. Third-party dig-in refers to when a person digging contacts underground electric infrastructure. Third-party elevated worker contact includes when a worker comes into contact with an overhead conductor. Finally, third-party aircraft wire strike occurs when a manned aircraft collides with overhead electrical infrastructure. SCE considers risk from unmanned aircraft elsewhere in its RAMP application.[934]

Observations and Findings

SPD has no observations or findings on SCE's description of the drivers for this risk.

Consequences

SCE identifies four potential outcomes of a public safety risk event: public contact from vehicle-hit pole (O1), public contact from dig-in (O2), third-party public contact with intact overhead (O3), and third-party public aircraft strike (O4).[935] These outcomes variously impact the utility's safety, reliability, and financial risk.

Observations and Findings

SPD has no observations or findings on SCE's public safety risk event outcomes or consequences.

---

[933] SCE 2026 RAMP Ch. 9, p. 9.

[934] Under its description of the risk driver "Third-Party Aircraft Wire Strike," SCE indicates "[i]ncidents involving unmanned aircraft systems (e.g., drones) are outside the scope of this risk, as such operations currently are less likely to result in direct electrical contact by a member of the public" (Ch.9, p. 12). In Ch. 9, Table II-2 "Public Safety Risk not Attributable to Asset Failure Chapter Scope" (p. 7), SCE states that "[c]ontact involving unmanned aircraft (e.g., drones)" is out-of-scope for this chapter, adding "[t]hose types of incidents are considered in the Overhead Equipment Failure chapter." In Ch. 5 "Overhead Equipment Failure," there is no mention of unmanned aircraft, however in the Ch. 12 "Physical Security" risk driver description for "D6 - UAS Penetration" (p. 14) SCE discusses its approach to assessing risk from unmanned aerial systems (e.g., drones).

[935] SCE 2026 RAMP Ch. 9, Figure II-1 "Risk Bowtie for Public Safety Risk not Attributable to Asset Failure," p. 8; p. 13.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[936]

For this risk, SCE has four controls, which it includes in all plans, and two mitigations, which it includes in its alternative plans along with the four controls.[937] The first control is a public outreach program (C1), which includes a mass media campaign and a targeted effort toward high-risk workers. The second control is a locate and mark program (C2), which allows excavators to know where SCE's underground infrastructure is. The third control is SCE's Vehicle Hit Pole Program (C3), which includes activities such as installing pole cushions and relocating or eliminating poles. The fourth control is a seminar series designed to educate third-party pilots operating near SCE's overhead infrastructure on how to reduce collisions (C4), which SCE proposes formalizing and expanding into an activity held every four years.[938]

One of SCE's potential mitigations is a program for burying plastic boards above underground infrastructure to warn future excavators of imminent contact with underground infrastructure (M1). The other potential mitigation is a program for installing more marking and lighting on overhead infrastructure than federal regulations require (M2).

Observations and Findings

SPD has no observations or findings on the controls and mitigations for this risk.

Alternatives Analysis

SCE analyzed two potential alternatives to its proposed plan.[939] SCE's first alternative would be aimed at reducing dig-in risk, warning excavators of imminent contact with infrastructure by burying plastic boards over underground conductors. SCE is not proposing this mitigation at present due to its untested nature, though it is evaluating it for feasibility. SCE's estimate of cost-effectiveness for this mitigation is low (with a benefit-cost ratio [BCR] of 0.23 using the hybrid discount rate).

The second alternative would be aimed at reducing aircraft wire strike risk by adding lighting and markings above the requirements of federal regulations for marking and lighting powerlines. SCE is not proposing

---

[936] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[937] SCE RAMP-9 Public Safety Risk Not Attributable To Asset Failure, pp. 18, 26.

[938] SCE RAMP-9 Public Safety Risk Not Attributable To Asset Failure, p. 26.

[939] SCE RAMP-9 Public Safety Risk Not Attributable To Asset Failure, pp. 32-35.

this mitigation at present because, although SCE indicates that the mitigation is feasible, SCE's estimate of its cost-effectiveness is very low (with a BCR of 0.003 using the hybrid discount rate).

Observations and Findings

SPD observes that the two alternative plans introduce mitigations with low BCRs, with the first alternative introducing a mitigation with unknown feasibility. Those are good reasons to reject these choices.

SPD notes that, although SPD could calculate plan BCRs using SCE's work papers, SCE's presentation of the proposed plan and alternatives does not include any overall plan BCRs,[940] and the Chapter 9 work paper with details on the second alternative does not include overall plan BCRs,[941] which impedes SPD's ability to compare overall BCRs across the three plans.

BCR Calculations

SCE calculates BCR values for four controls and two mitigations for public safety risk. Table 6-1 provides the BCRs of the four controls in SCE's proposed plan. As noted above, SCE includes its two potential mitigations for this risk in its alternative plans but not in its proposed plan.

[940] The three plan summary tables which in other risk chapters present total plan costs and overall plan BCRs, but which do not in this chapter alone, are titled here Table VI-7 "Proposed Plan (Total Costs and Benefit-Cost Ratios (BCRs)) (p. 30), Table VII-9 "Alternative Plan #1 (Total Costs & BCRs)" (p. 33), and Table VII-10 "Alternative Plan #2 (Total Costs & BCRs)" (p. 34). These tables only present total costs and BCRs for individual controls and mitigations, not the overall plans.

[941] SCE 2026 RAMP Ch. 9 work paper "SCE 2026 RAMP_Public Safety_Alternative 2" spreadsheet.

Table 6-1. SCE Proposed Plan Projects, Costs, and BCRs (2029-2032) ($000s)[942]

Mitigation ID	Control/Mitigation Name	O&M Costs	Capital Costs	Total Costs	BCR (Societal)	BCR (Weighted-Average Cost of Capital - WACC)	BCR (Hybrid)
C1	Public Outreach – Intact Contact	$14,482		$14,482	1.19	1.19	1.28
C2	Locate and Mark – Distribution	$147,768		$147,768	0.46	0.46	0.49
C3	Vehicle Hit Pole Program		$6,000	$6,000	8.43	2.01	2.66
C4	Aircraft Wire Strike Seminar	$33		$33	25.67	23.74	25.61
	Total*	**$162,283**	**$6,000**	**$168,283**	**0.80**[943]	**0.58**	**0.64**

* Total numbers for costs and total plan BCRs calculated by SPD.

Three proposed controls have a BCR greater than one. The one control with a BCR less than one, the Locate and Mark – Distribution program, is mandated by California law and therefore needs to be completed regardless of BCR.[944]

Table 6-2 presents the total costs and overall BCRs for the proposed plan compared to the two alternative plans.

[942] SCE 2026 RAMP Ch. 9, Table VI-7 "Proposed Plan (Total Costs and Benefit-Cost Ratios (BCRs))," p. 30.

[943] BCR calculations were derived by SPD staff using the following sources: SCE 2026 RAMP Chapter 9 work papers "SCE 2026 RAMP_Public Safety_Proposed" and "SCE 2026 RAMP_Public Safety_Proposed VHP."

[944] California Government Code 4216 (https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=GOV&division=5.&title=1.&part=&chapter=3.1.&article=2., accessed Aug. 5, 2026).

Table 6-2. BCR Calculations for Proposed and Alternative Plans (2029-2032) ($000s)[945]

Plan Name	O&M Costs*	Capital Costs*	Total Costs*	BCR (WACC)	BCR (Societal)	BCR (Hybrid)
Proposed Plan	$162,283	$6,000	$168,283	0.58	0.80	0.64
Alternative 1[946]	$162,283	$14,571	$176,854	0.56	0.78	0.62
Alternative 2[947]	$162,493	$9,905	$172,398	0.56**	0.77**	0.62**

* Total numbers for costs calculated by SPD.
** Alternative 2 overall plan BCRs calculated by SPD.

Observations and Findings

As noted above, SPD observes that SCE's two alternative plans introduce mitigations with low BCRs, with the first alternative introducing a mitigation with unknown feasibility.

Also noted above, SPD was impeded in comparing overall BCRs for the three plans by the lack of overall BCRs for the proposed plan and alternatives in the chapter's presentation of the plans and by the omission of overall plan BCRs from the Chapter 9 work paper on the second alternative (although SPD was able to calculate these BCRs using SCE's work papers).[948] Additionally, there is an error in the table presenting SCE's second alternative plan's BCRs, with SCE omitting the total cost for Marking & Lighting of Overhead Wires – Beyond FAA Compliance (M2).[949]

[945] SCE 2026 RAMP Ch. 5, Table VII-21 "Overhead Equipment Failure Proposed Plan and Alternative Plans Summary of Control Program Estimated Costs and Benefit-Cost Ratios for 2029-2032," p. 40.

[946] BCR calculations were calculated by SPD using the following SCE 2026 RAMP Ch. 9 work papers: "SCE 2026 RAMP_Public Safety_Proposed.xlsm," "SCE 2026 RAMP_Public Safety_Proposed VHP.xlsx," and "SCE 2026 RAMP_Public Safety_Alternative 1.xlsm" spreadsheets.

[947] BCR calculations were calculated by SPD using the following sources: SCE 2026 RAMP Chapter 9 work papers "SCE 2026 RAMP_Public Safety_Proposed.xlsm," "SCE 2026 RAMP_Public Safety_Proposed VHP.xlsx," and "SCE 2026 RAMP_Public Safety_Alternative 2.xlsx" spreadsheets.

[948] SCE 2026 RAMP Ch. 9 work paper "SCE 2026 RAMP_Public Safety_Alternative 2.xlsx" spreadsheet.

[949] SCE 2026 RAMP Ch. 9, Table VII-10 "Alternative Plan #2 (Total Costs & BCRs)," p. 34.

Summary of Findings

SPD finds that:

1. SCE did not provide information on its non-quintile tranching method for its most important subcategory of risk, vehicle hit, until after it filed its 2026 RAMP application. This prevented stakeholders from being able to comment on SCE's vehicle hit tranching method in advance of the RAMP filing.
2. SCE does not provide RRUs for its Locate and Mark – Distribution control, which is specific to electric operations and has a RAMP cycle cost of over $10 million; it also does not provide any explanation why it does not define RRUs for this program.
3. SCE does not provide total costs or overall plan BCRs in its three tables summarizing total costs and BCRs for its three plans, although SCE provides sufficient information to calculate the BCRs in its work papers.

Recommendations to Address Findings

1. In future RAMP proceedings, SCE should make every effort to include all departures from the default quintile tranching method in its white paper on tranching methods filed 45 days before its first pre-RAMP workshop to allow sufficient time for stakeholder input.
2. SPD recommends SCE include in its next General Rate Case (GRC) cycle RRUs for its Locate and Mark – Distribution control or include an explanation of why the utility believes the RRU requirement does not apply.
3. In future proceedings, SCE should carefully proofread all documents prior to submission to make sure important numbers are not omitted from its tables, such as plan BCRs.

7. Cyber Attack

Risk Description

The Southern California Edison Company (SCE) defines cyber attack risk as a compromise of cybersecurity system controls which may lead to disruption of utility operations through loss of data, loss of data integrity, loss of system control, adversary takeover of grid control or Supervisory Control and Data Acquisition (SCADA) systems, ransomware attacks, and other similar malicious activities.[950] SCE notes that a cyber attack could result in an interruption of the ability to deliver electricity to customers— including loss of the grid for an extended period, catastrophic outcomes at the individual or community level, loss of intellectual property, and confidential data being compromised.[951]

SCE specifies its scope for this Risk Assessment and Mitigation Phase (RAMP) chapter as including unauthorized access to the bulk electric system and distribution controls, SCADA, Industrial Control System (ICS), and administrative and customer data systems.[952] SCE indicates that secondary impacts associated with cyber-attacks out of scope for this chapter.[953]

Observations and Findings

SCE provides a clear definition and scope but explicitly excludes secondary impacts from its scope.[954]

SCE should consider including in its scope for cyber attack risk the secondary impacts of outages with safety and reliability ramifications.

[950] SCE 2026 RAMP, Chapter 10 "Cyber Attack," p. 1; p. 5; Figure II-1 "Risk Bowtie for Cyber Attack," p. 12; p. 16.

[951] SCE 2026 RAMP, Ch. 10, p. 16.

[952] SCE 2026 RAMP, Ch. 10, Table II-2 "Scope for SCE's 2026 Cyber Attack RAMP Analysis," p. 5.

[953] SCE 2026 RAMP, Ch. 10, Table II-2 "Scope for SCE's 2026 Cyber Attack RAMP Analysis," p. 5.

[954] SCE 2026 RAMP, Ch. 10, Table II-2 "Scope for SCE's 2026 Cyber Attack RAMP Analysis," p. 5.

Risk Bow Tie

SCE presents the following risk bow tie for cyber attack risk:

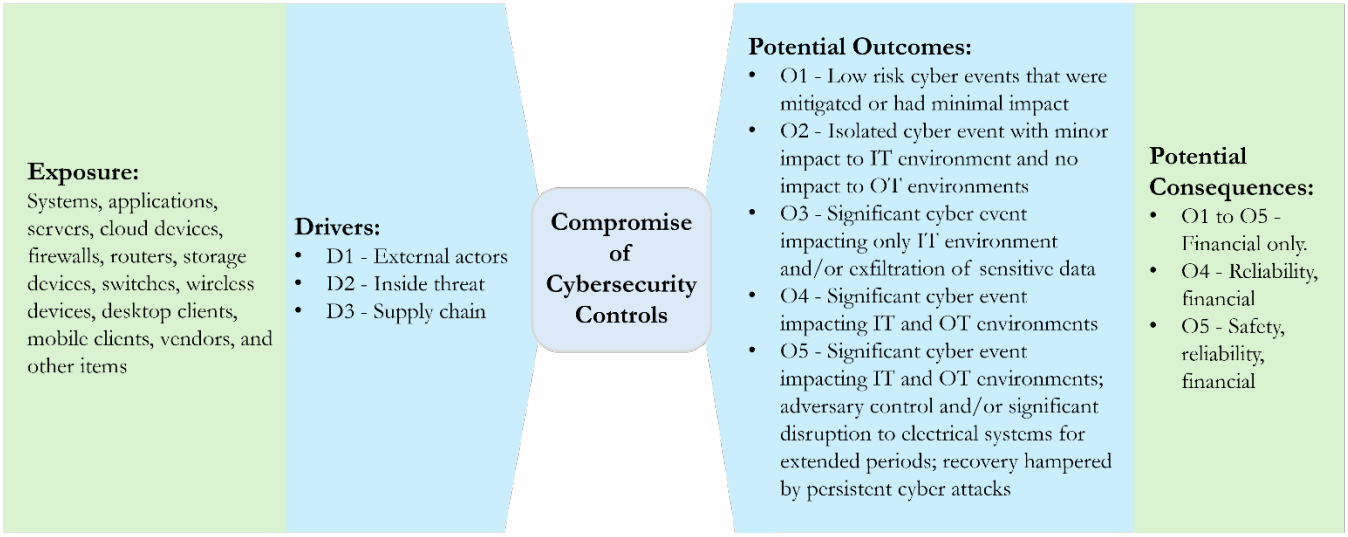


Figure 7-1. SPD Adaptation of SCE Cyber Attack Risk Bow Tie.[955]

In the bow tie and following discussion, the acronym "IT" refers to Information Technology while "OT" refers to Operating Technology. SCE notes that while it modeled how controls may affect "the risk reduction in driver frequencies" for this RAMP chapter, it "did not model how the controls may impact outcomes or consequences."[956]

Observations and Findings

Per RDF requirements,[957] SCE provides a bow tie illustration that gives an overview of how the risk was assessed.[958] SPD notes that while SCE states it did not model how controls may impact outcomes, controls will not always impact both the frequency of drivers and the magnitude of outcomes; reduction of driver

---

[955] SCE 2026 RAMP, Ch. 10, Figure II-1 "Risk Bowtie for Cyber Attack," p. 12.

[956] SCE 2026 RAMP, Ch. 10, p. 22.

[957] Phase 4 Decision with Appendices (D.25-08-032 of Aug. 29, 2025). (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=578198350, accessed May 27, 2026). This decision closed R.20-07-013.

[958] D.25-08-032, Appendix A, Row 15, p. A-16.

frequency is often effective at reducing risk incidents and thus fewer outcomes occur. appropriate for a bow tie graphic.

Exposure

SCE defines its cyber attack risk exposure as its 2026 essential/critical systems, information technology (IT) equipment, IT software, vendors, employees, and customer data.[959] In its cyber attack risk bow tie, SCE defines the exposure to include systems, applications, servers, cloud devices, firewalls, routers, storage devices, switches, wireless devices, desktop clients, mobile clients, vendors, and other items.[960]

Observations and Findings

SPD has no observations or findings on the exposure.

Tranches

SCE departs from the default quintile tranching methodology for this risk.

In its 2026 RAMP application, SCE increases the number of tranches to five from the three it presented in its 2022 RAMP application: Bulk Electric System (BES), Distribution Grid, and Admin.[961] In 2026, SCE aggregates BES and Distribution Grid into the Grid tranche and divides the Admin tranche into subcategories with distinct risk profiles: Admin, Third Parties, Employees, and Applications.[962]

SCE defines the five resulting tranches as follows:[963]

1. Admin: The network environment and infrastructure supporting SCE's internal business operations.
2. Third Parties: Personnel from external organizations that provide goods or services to SCE (often with access to sensitive information).
3. Employees: SCE employees, particularly those with access credentials and system-level permissions, representing a key vector for cybersecurity threats.
4. Applications: Software used to operate the business, including Commercial-Off-The-Shelf (COTS), custom-built, cloud-based, and on-premises systems.

---

[959] SCE 2026 RAMP, Ch. 10, p. 11.

[960] SCE 2026 RAMP, Ch. 10, Figure II-1 "Risk Bowtie for Cyber Attack," p. 12.

[961] SCE 2026 RAMP, Ch. 10, p. 20.

[962] SCE 2026 RAMP, Ch. 10, p. 20.

[963] SCE 2026 RAMP, Ch. 10, p. 21.

5. Grid: SCE's network environment and infrastructure used for all utility operations, including transmission, distribution, and generation, with special attention to SCE's Supervisory Control and Data Acquisition (SCADA) network and grid control systems.

In SCE's white paper proposing alternatives to the quintile tranching methodology for several RAMP risks including cyber attack risk,[964] it explains that its new approach to tranching for this risk was to "better reflect a more advanced understanding of how cybersecurity threats are managed, including the application of mitigations and controls across organizational units, technology stacks, and business processes."[965]

Observations and Findings

SPD has no observations or findings on the tranches.

Risk Reporting Units (RRUs)

SCE did not define RRUs for this risk.

Observations and Findings

The RDF Phase 4 Decision requires that utilities define an RRU for each mitigation, with some exemptions.[966] Risk mitigation categories that the Phase 4 Decision exempted from needing RRUs to be defined are PSPS and protective equipment device settings.[967] Other than these, the Phase 4 Decision required SCE to define RRUs for mitigation programs costing $10 million or more. For the purposes of this report, SPD is interpreting the $10 million threshold to pertain to the cost of the mitigation program over the course of the four-year RAMP cycle.[968]

---

[964] SCE submitted "SCE 2026 RAMP Tranching White Paper" November 3, 2025; SCE submitted the "Chapter 2 Risk Model and BRC [sic] Methodology Tranching Whitepaper," indicating updates to its approach to tranching for 2026, May 27, 2026.

[965] SCE 2026 RAMP Tranching White Paper, p. 7.

[966] D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[967] "The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following: 1. Public Safety Power Shutoffs; 2. Protective Equipment Device Settings; 3. Mitigation and Control Programs that do not meet the following thresholds: a. For PG&E and SCE, $10 million…" from D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[968] D.25-08-032, p. 67 ("establishing a cost threshold for mitigation and control programs based on the same thresholds found in the Phase 1 Decision…"), which in turn points to the RDF Phase 1 Decision, D.21-11-009, p. 141, where the cost threshold is described as "the aggregate cost over the upcoming GRC funding period."

In its proposed plan, SCE reports that all six of its cyber attack risk controls exceed the $10 million threshold.[969] SPD notes that none fall under the categories of PSPS or protective equipment device settings:[970]

- Perimeter Defense (C1), with a full cycle cost of $247,403,000.
- Interior Protection (C2), with a full cycle cost of $75,200,000.
- Data Protection (C3), with a full cycle cost of $108,867,000.
- SCADA Cybersecurity (C4), with a full cycle cost of $28,823,000.
- Grid Modernization Cybersecurity (C5), with a full cycle cost of $421,414,000.
- North American Electric Reliability Corporation (NERC) Cybersecurity (C6), with a full cycle cost of $14,269,000.

SCE does not provide RRUs, explaining that "the proposed controls and mitigation activities for this risk falls [sic] outside of the definition of electric operations."[971] SPD notes that the definition of RRUs from the RDF Phase 4 Decision specifies that RRUs are a "CPUC jurisdictional effort within Electric Operations or Gas Operations…."[972] SCE asserts that its cyber security controls do not impact electric operations and thus RRUs are not a requirement.

However, at least one of the proposed risk controls, the NERC Cybersecurity control (C6), may engage with electric operations and so trigger the RRU requirement. Researching NERC Critical Infrastructure Protection (CIP) standards, SPD found: "NERC CIP is a set of mandatory cybersecurity rules for companies that operate the North American power grid. It tells you how to protect the computer systems, networks, and physical assets that keep the grid running."[973] SPD finds that use of NERC CIP standards may constitute a control that does impact electric operations and recommends that SCE provide a justification for not defining RRUs for this and other cyber attack risk controls.

---

[969] SCE 2026 RAMP Ch. 10, Table VI-8 "Proposed Plan Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 35.

[970] SCE 2026 RAMP Ch. 10, Table VI-8 "Proposed Plan Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 35.

[971] SCE 2026 RAMP, Ch. 10, p. 21.

[972] D.25-08-032, Appendix A, p. A-7.

[973] SCADA Protocols web page NERC CIP Compliance: Complete Guide to All CIP Standards (June 21, 2026) (https://scadaprotocols.com/what-is-nerc-cip/, accessed Sept. 30, 2026). SCADA Protocols, per its About Us web page (2026), is "a technical platform dedicated to helping engineers understand, analyze, and troubleshoot industrial communication systems" (https://scadaprotocols.com/about-us/, accessed Sept. 30, 2026).

Risk Drivers

In its risk bow tie, SCE presents three potential leading indicators for this risk, or drivers.[974] They are external actors (D1), inside threat (D2), and supply chain (D3). SCE provides descriptions of these drivers, including motivations and examples for each, including references to industry threat reports.[975]

Regarding data limitations about the drivers, SCE notes, "We evaluated these drivers using industry data, which is limited in nature as expected," adding "most utilities and companies that employ SCADA/ICS technologies are reluctant to disclose information or vulnerabilities since sharing this information may put their systems at greater risk of future attack."[976] SCE also notes that it is hard to analyze a specific outcome due to the level of interconnectedness of systems and the variety of methods used by cyber attackers.[977] SCE based its analysis in part "on public data released by the federal government and industry experts" and the triggering event frequency estimate using the 2025 Verizon Data Breach Incident Reports. [978]

Regarding larger uncertainties around the drivers of cyber attack risk, SCE remarks on the "sophistication of cyber attack methods and shifting geopolitical tensions," adding that SCE's risk mitigation strategies may need to "evolve to remain effective as the global threat environment changes."[979] In addition to discussing the geopolitical landscape, SCE mentions factors that may not be cyber attack risk drivers, but could compound the impact of a cyber attack, including a major physical security breach, widespread outage, and the loss of control of transmission and substation assets.[980]

Observations and Findings

SPD observes that SCE clearly illustrates three appropriate drivers as potential actors and describes its data limitations about the drivers. While SPD understands the constraints on transparency around the drivers of this risk, SPD encourages SCE to share information on triggering event frequency where possible.

---

[974] SCE 2026 RAMP, Ch. 10, Figure II-1 "Risk Bowtie for Cyber Attack," p. 12.

[975] SCE 2026 RAMP, Ch. 10, pp. 12-15.

[976] SCE 2026 RAMP, Ch. 10, p. 15.

[977] SCE 2026 RAMP, Ch. 10, p. 15.

[978] SCE 2026 RAMP, Ch. 10, p. 16.

[979] SCE 2026 RAMP, Ch. 10, p. 37.

[980] SCE 2026 RAMP, Ch. 10, Table II-3 "Related Factors Impacting Cyber Attack," p. 22.

Risk Driver Frequencies

As noted above, SCE estimates the triggering event frequency based on 2025 Verizon Data Breach Incident Reports.[981]

SCE includes annualized frequency data in its risk bow tie for cyber attack.[982] Risk events associated with external actors (D1) are the most frequent, estimated at 38 risk events per year, with risk events associated with inside threat (D2) and supply chain (D3) trailing far behind, at 4.3 and 2.2 risk events per year respectively.[983] SCE categorizes within the external actor category of risk driver cyber crime actors, cyber terrorism and hacktivism actors, and nation-state-sponsored actors.[984]

Observations and Findings

SPD has no observations or findings on the risk driver frequencies.

Consequences

SCE identifies five potential outcomes of a cyber attack risk event:[985]

- Low risk cyber events that were mitigated or had minimal impact (O1).
- Isolated cyber event with minor impact to information technology (IT) environment and no impact to operating technology (OT) environments (O2).
- Significant cyber event impacting only IT environment and/or exfiltration of sensitive data (O3).
- Significant cyber event impacting IT and OT environments (O4).
- Significant cyber event impacting IT and OT environments; adversary control and/or significant disruption to electrical systems for extended periods; recovery hampered by persistent cyber attacks (O5).

SCE estimates that the potential consequences of O1 to O3 are only financial, while the O4 could have reliability and financial consequences, and O5 could have safety, reliability, and financial consequences.

---

[981] SCE 2026 RAMP, Ch. 10, p. 16.

[982] SCE 2026 RAMP, Ch. 10, Figure II-1 "Risk Bowtie for Cyber Attack," p. 12.

[983] SCE 2026 RAMP, Ch. 10, Figure II-1 "Risk Bowtie for Cyber Attack," p. 12.

[984] SCE 2026 RAMP, Ch. 10, pp. 12-14.

[985] SCE 2026 RAMP, Ch. 10, Figure II-1 "Risk Bowtie for Cyber Attack," p. 12.

For O5, the lowest probability but highest consequence outcome, SCE clarifies that not only would there be "denial of use" (as in O4), but operating technology (OT) systems would be "erratic, unpredictable, potentially destructive, and/or … under adversary control."[986]

In estimating safety consequences for this outcome, SCE assumes one injury and one fatality; for reliability consequences, SCE assumes a 3-day outage for one million customers; for reliability consequences for this outcome, SCE's estimate is "based on cybersecurity Subject Matter Expert estimates and publicly available data."[987]

Observations and Findings

SCE's exclusion of secondary impacts likely understates consequences for the more severe outcomes. As noted above, SCE should consider including scoping the secondary impacts from a cyber attack, including outages with safety and reliability ramifications.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[988]

SCE proposes six control programs to address the likelihood and consequences of cyber attack risk events. It includes these six control programs in its proposed plan and both alternative plans. SCE doesn't propose any mitigation programs for this risk in its 2026 RAMP.

SCE's six control programs for this risk are:[989]

- Perimeter Defense (C1)
- Interior Protection (C2)
- Data Protection (C3)
- SCADA Cybersecurity (C4)
- Grid Modernization Cybersecurity (C5)
- North American Electric Reliability Corporation (NERC) Cybersecurity (C6)

---

[986] SCE 2026 RAMP, Ch. 10, p. 19.

[987] SCE 2026 RAMP, Ch. 10, p. 20.

[988] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[989] SCE 2026 RAMP, Ch. 10, Table VI-8 "Proposed Plan Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 35.

SCE states that Perimeter Defense (C1) intercepts external attacks and, as such, reduces the frequency of all risk drivers (external actors, inside threat, and supply chain).[990] SCE states that Interior Protection (C2) addresses the insider threat driver, securing internal systems from unauthorized users, devices, and software.[991] SCE notes that Data Protection (C3) reduces the frequency of all risk drivers, as it "safeguards the computing environment housing SCE's core information."[992] SCE states that its SCADA Cybersecurity program (C4), Grid Modernization Cybersecurity (C5), and NERC Cybersecurity (C6) reduce the frequency of all risk drivers.[993] The SCADA Cybersecurity control, a kind of perimeter defense program, targets risk reduction measures at the SCADA systems that remotely control and monitor the grid.[994] SCE indicates its Grid Modernization Cybersecurity control aims to pursue upgrades in order to "detect, isolate, fix or remove, and restore electric distribution grid systems and devices as quickly and efficiently as possible."[995] SCE notes that the NERC Cybersecurity control is aimed at compliance with the NERC Critical Infrastructure Protection (CIP) standard.[996]

Observations and Findings

SPD has no observations or findings on the controls for this risk.

Alternatives Analysis

In addition to its proposed plan, SCE presents two alternatives. As noted above, both alternatives include all six cyber attack controls that SCE includes in its proposed plan. Alternative 1 is like the proposed plan but presents the "least cost option," with a reduced scope that reduces operating costs by 10 percent; it likewise reduces the effectiveness of its cyber attack risk controls.[997] Alternative 2 is like the proposed plan but increases operating costs by 10 percent, with an associated increased scope.[998] It presents "accelerated cybersecurity enhancement," which would reduce the most risk but also presents feasibility challenges

[990] SCE 2026 RAMP, Ch. 10, pp. 23-24.

[991] SCE 2026 RAMP, Ch. 10, p. 24.

[992] SCE 2026 RAMP, Ch. 10, p. 25.

[993] SCE 2026 RAMP, Ch. 10, pp. 26-31.

[994] SCE 2026 RAMP, Ch. 10, p. 26.

[995] SCE 2026 RAMP, Ch. 10, p. 28.

[996] SCE 2026 RAMP, Ch. 10, p. 30.

[997] SCE 2026 RAMP, Ch. 10, pp. 37-38.

[998] SCE 2026 RAMP, Ch. 10, p. 41.

related to "the current maturity status of the technologies required and … operational challenges."[999] SCE notes that it does not believe the expense of this plan is justified at this time.[1000]

The proposed plan benefit-cost ratios (BCRs) are 4.46, 4.02, and 4.44 (societal, weighted-average cost of capital [WACC], and hybrid discount rate scenarios respectively); the Alternative 1 plan BCRs are 3.44, 3.09, and 3.43 (societal, WACC, and hybrid respectively); the Alternative 2 plan BCRs are slightly higher than those of Alternative 1, but still slightly lower than those of the proposed plan at 4.41, 3.98, and 4.41 (societal, WACC, and hybrid respectively).[1001]

SCE believes its proposed plan includes "adequate cyber defense strategies for the known threats that exist today" and "capabilities, tools, and resources to address the growth of cyber attack risks" in the future, balancing cost and risk reduction.[1002]

Observations and Findings

SPD observes that the two alternatives have lower BCRs than SCE's proposed plan under all discounting methods, and the relatively aggressive plan with the highest risk reduction presents feasibility challenges, good reasons to reject the alternative plans.

BCR Calculations

SCE calculates BCR values for its six cyber attack risk controls under the three discount rate scenarios—societal, WACC, and hybrid—for its proposed plan.[1003] In Table 7-1 SPD presents the total costs and BCRs (hybrid scenario) for SCE's proposed plan.

[999] SCE 2026 RAMP, Ch. 10, pp. 41-43.

[1000] SCE 2026 RAMP, Ch. 10, p. 43.

[1001] SCE 2026 RAMP, Ch. 10, Table VI-6 "Cyber Attack Proposed Plan and Alternative Plans: Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 33.

[1002] SCE 2026 RAMP, Ch. 10, pp. 35-36.

[1003] SCE 2026 RAMP, Ch. 10, Table VI-8 "Proposed Plan Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 35.

Table 7-1. SCE's Proposed Plan BCR Calculation Summary (2029-2032)[1004]

Control ID	Control Name	Total Costs ($000s)	BCR (Hybrid)
C1	Perimeter Defense	$247,403	4.59
C2	Interior Protection	$75,200	5.99
C3	Data Protection	$108,867	3.73
C4	SCADA Cybersecurity	$28,823	15.62
C5	Grid Modernization Cybersecurity	$421,414	3.37
C6	NERC Cybersecurity	$14,269	8.24

Observations and Findings

SPD observes that SCE has relatively high BCRs for its six cyber attack risk controls compared to BCRs of several other risk mitigation programs in its 2026 RAMP, ranging from 3.37 to 15.62 (hybrid). For example, the Public Safety Power Shutoff (PSPS) mitigation BCRs range between 0.03 and 0.99 (hybrid) with an average BCR (hybrid) of about 0.21 (SPD calculation).[1005]

Summary of Findings

SPD finds that:

1. SCE explicitly excludes secondary impacts from its scope for cyber attack risk.
2. SCE does not provide RRUs for its cyber attack risk control programs with a RAMP cycle cost of over $10 million and it provides an insufficient explanation of why it does not define RRUs. For example, the NERC Cybersecurity control (C6) may involve electric operations and thus trigger the RRU requirement.

[1004] SCE 2026 RAMP, Ch. 10, Table VI-8 "Proposed Plan Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 35.

[1005] SCE 2026 RAMP Chapter 4 "Wildfire and PSPS," Table XIII-61 "Proposed Plan Programmatic PSPS Estimated Spend ($000s) and Benefit-Cost Ratios," p. 120.

3. SCE's exclusion of secondary impacts likely understates consequences for the more severe outcomes.

Recommendations to Address Findings

SPD recommends that SCE:

1. Consider including in its scope for cyber attack risk the secondary impacts of outages with safety and reliability ramifications, adding the estimated costs of these impacts to its calculation of the consequences of a risk event (CoRE), particularly in the case of the more severe outcomes.
2. SPD recommends SCE include in its next GRC cycle RRUs for its cyber attack risk control programs with a RAMP cycle cost of over $10 million or include a more thorough explanation of why the utility believes the RRU requirement does not apply.

8. Seismic Risk

Risk Description

The Southern California Edison Company (SCE) defines seismic risk as risk from "the occurrence of a significant earthquake that threatens the safety, reliability, and operational continuity of SCE's diverse asset portfolio, including "electric infrastructure, non-electric buildings, IT/Telecom facilities, generation assets, and emergency communication sites."[1006] SCE reports that its Seismic Resiliency Program addresses this risk by assessing, prioritizing, and mitigating seismic risks, with a goal of ensuring life safety, minimizing service disruptions, and enabling rapid system recovery following a catastrophic seismic event.[1007]

SCE cites the United States Geological Survey (USGS) and Federal Emergency Management Agency (FEMA) as stating that Southern California "encompasses half of the nation's earthquake risk," with Los Angeles County ranked highest for seismic risk nationally, and other counties in SCE's service territory "also ranked very highly."[1008] SCE points to the greatest risk stemming from the co-location of active earthquake faults with dense population centers, which are also sites of dense power grid infrastructure.[1009] Adding to the challenge of managing SCE's seismic risk is the fact that, as SCE notes, much of its critical infrastructure "is housed in older buildings, some designed and built before the existence of any seismic building code provisions."[1010]

SCE evaluates seismic risk in its 2026 Risk Assessment and Mitigation Phase (RAMP) application although, in ranking its enterprise risks by monetized safety risk value (using only the safety attribute) for selection for the 2026 RAMP risk evaluation process per the Risk-Based Decision-Making Framework requirements,[1011] seismic risk did not fall into SCE's top 40 percent of enterprise risks, thus falling outside the required level of risk for further evaluation (for more on this, see "SCE's RAMP Risk Selection Process" above).[1012, 1013] In

---

[1006] SCE 2026 RAMP, Chapter 11 "Seismic," p. 6.

[1007] SCE 2026 RAMP, Ch.11, p. 6.

[1008] SCE 2026 RAMP, Ch.11, p. 2.

[1009] SCE 2026 RAMP, Ch. 11, p. 2.

[1010] SCE 2026 RAMP, Ch. 11, p. 3.

[1011] Phase 4 Decision with Appendices (D.25-08-032 of Aug. 29, 2025).
(https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=578198350, accessed May 27, 2026).
This decision closed R.20-07-013.

[1012] D.25-08-032, Appendix A, Row 9, p. A-12.

[1013] SCE's Pre-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop Presentation, Dec. 18, 2025, slide 14 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-pre-filing-ramp-workshop-slides_dec-2025.pdf, accessed July 10, 2026).

this initial evaluation, it came eighth in the list of SCE's top 11 risks ranked by safety risk value, but when SCE evaluated those 11 risks by all three attributes—safety, reliability, and financial—seismic came in fifth, driven mainly by the high estimated value of reliability risk associated with seismic risk.[1014] SCE began treating seismic risk as a separate risk in the 2022 RAMP, having first treated it as a subpart of building safety risk in its 2018 RAMP.[1015]

Table 8-1 provides SCE's definition of the risks considered in- and out-of-scope for this RAMP chapter.[1016]

[1014] SCE's Post-Filing 2026 Risk Assessment and Mitigation Phase (RAMP) Workshop Presentation, June 25, 2026, slide 9 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-2026-post-filing-ramp-workshop-slides_062526.pdf, accessed Oct. 5, 2026).

[1015] SCE 2022 RAMP, Chapter 1 "Overview," p. 3.

[1016] SCE 2026 RAMP, Ch. 11, Table II-2 "Seismic Risk Chapter Scope," p. 11.

Table 8-1. Seismic Risk Scope[1017]

Item	Seismic Risk Element Description
In Scope	• Electric Infrastructure (substations, Mechanical Electrical Equipment Room(s), transmission structures) • Non-electric buildings (offices, critical facilities) • Information Technology (IT)/Telecom facilities (racks, equipment, bracing) • Generation assets (including blackstart capabilities) • Communications facilities (includes racks, structures, and backup power at hilltop and mountaintop sites) • Project prioritization based on occupancy, criticality, and reliability
Out of Scope	• Assets not owned or operated by SCE (3rd party) • Non-critical or low occupancy buildings • Buildings or trailers leased by SCE • Buildings in process of sale or demolition • Indirect economic impacts beyond SCE operational control • Risks unrelated to safety, reliability, or operational continuity
Data Sources	• Uniform California Earthquake Rupture Forecast • SCE's asset inventory and tranching data

Key Changes from SCE's 2022 RAMP to 2026 RAMP

SCE has continued to refine its seismic risk analysis with a more detailed modeling approach than in its 2022 RAMP. Previously, SCE categorized earthquakes by levels of severity (catastrophic, severe, and moderate) based on magnitude ranges; in its 2026 RAMP, SCE uses a single threshold level of ground shaking, specifically "a shaking level of 0.05 g peak ground acceleration," where "g" stands for gravity, "occurring at one or more [of] SCE's tranche 1, 2 or 3 facilities" (tranches being the way SCE classifies its facilities by level of criticality).[1018] SCE notes that it chose this threshold "as a result of design specifications employed and based on the past several decades of actual performance."[1019] SCE further notes that using a

[1017] SCE 2026 RAMP, Ch. 11, Table II-2 "Seismic Risk Chapter Scope," p. 11.

[1018] SCE 2026 RAMP, Ch. 11, p. 12 and p. 15.

[1019] SCE 2026 RAMP, Ch. 11, p. 15.

single threshold of ground shaking allows "more advanced resolution in modeling."[1020] SCE says that this new approach provides "a more accurate depiction of outcomes and consequences."[1021]

Since 2022, in addition to switching to a single threshold for an earthquake risk event, SCE reports that it is using updated software to calculate risk, such as the new version of Open-Source Seismic Hazard Analysis (OpenSHA) software[1022] and the new CHaT software, which can drive larger scale modeling.[1023, 1024]

For its 2026 RAMP assessment, SCE included data on more facilities. As of its 2022 RAMP, SCE had screened 319 facilities while as of the current RAMP it had screened 532 facilities, ranking all facilities by collapse risk using the same screening methodology.[1025] SCE reports that it has about 700 facilities left to screen, which it expects to assess within the next two years.[1026]

Observations and Findings

Observations About Key Changes from SCE's 2022 RAMP to 2026 RAMP

In keeping with an asset-based risk analysis, Safety Policy Division (SPD) observes that the single threshold approach to defining seismic risk events focuses on the vulnerability of buildings and infrastructure, categorized by how critical the asset is to operations. SPD discusses this more fully below, under Tranches.

[1020] SCE 2026 RAMP, Ch. 11, p. 12.

[1021] SCE 2026 RAMP, Ch. 11, p. 18.

[1022] Open-Source Seismic Hazard Analysis (OpenSHA) website (2026) by University of Southern California (https://opensha.org/, accessed Oct. 5, 2026).

[1023] SCE 2026 RAMP, Ch. 11, p. 17.

[1024] Comprehensive Hazards Assessment Tool (CHaT) (https://database.epicpartnership.org/project/32505, accessed Oct. 9, 2026).

[1025] SCE 2026 RAMP, Ch. 11, p. 12.

[1026] SCE 2026 RAMP, Ch. 11, p. 47.

Risk Bow Tie

SCE presents the following risk bow tie for seismic risk:

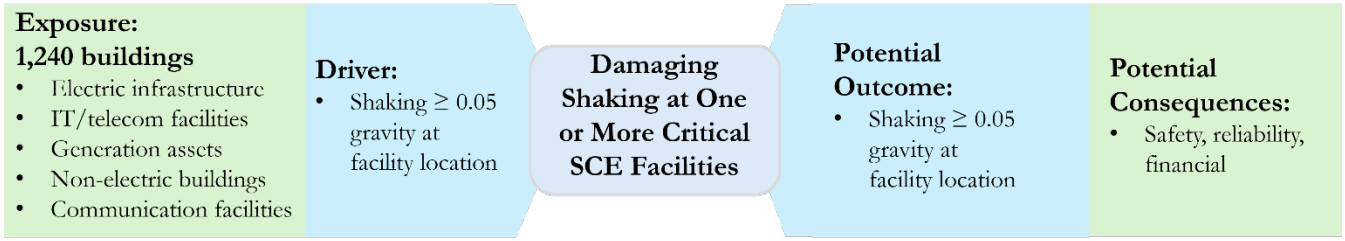


Figure 8-1. SPD Adaptation of SCE Seismic Risk Bow Tie.[1027]

Observations and Findings

SPD finds that SCE's seismic bow tie diagram does not clearly distinguish between the risk driver, triggering event, and outcome because it defines each in the same way, as shaking greater than or equal to 0.05 g at one or more SCE facilities or critical facilities.

In response to a data request from SPD about this seeming redundancy, SCE clarified its seismic bow tie diagram as follows:[1028]

- The risk driver is the occurrence of an earthquake that causes at least 0.05 g in peak horizontal ground acceleration at one or more assets.
- The triggering event is physical damage to an SCE asset because of the driver occurring.
- Regarding the outcome, SCE points to Section E of its seismic risk chapter, where the outcome is defined as "shaking greater than or equal to 0.05 g at one or more of SCE's tranche 1, 2 or 3 facilities."[1029]

SCE further clarified in its data request response, "In many ways, SCE uses the 0.05g peak ground acceleration (PGA) threshold as a modeling criterion within its seismic risk assessment framework; it is not intended to independently define all elements of the bowtie."[1030] SCE adds that its repeated appearance in the bow tie diagram "reflects its use as a consistent reference point within the modeling framework."[1031]

SCE further added that "the bowtie is an imperfect representation of earthquake risk due to the continuous range of possible magnitudes, locations, and resulting ground motion. Many earthquakes can cause

---

[1027] SCE 2026 RAMP Ch. 11, Figure II-3 "Risk Bowtie for Seismic Risk," p. 15.

[1028] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 61(a).

[1029] SCE 2026 RAMP Ch. 11, p. 17.

[1030] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 62.

[1031] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 62.

horizontal peak ground acceleration of 0.05g or greater. These events can span a wide range of magnitudes, frequencies', and consequence levels, from relatively minor shaking to large high-impact earthquakes."[1032] And, for "consistency, SCE defines the driver occurrence as the rate at which an earthquake causes peak ground acceleration of 0.05g or greater at one or more SCE sites. The associated consequences are defined as the conditional loss given an earthquake rupture that causes [peak ground acceleration or] PGA > 0.05g. This approach ensures that the model captures both the frequency of lower-intensity shaking and the disproportionately higher consequences associated with rare, large-magnitude events, rather than relying on a single representative scenario."[1033]

Exposure

SCE defines its seismic risk exposure as 1,240 buildings, including electric infrastructure, IT/telecom facilities, generation assets, non-electric buildings, and communication facilities.[1034] SCE notes that its RAMP analysis covers 1,266 facilities in all, some retrofitted, some not, but it only includes 1,240 facilities in its benefit-cost ratio (BCR) calculations "because 26 out of the 1,266 buildings have been retrofitted from 2016-2025" (i.e., SCE is only including in its exposure and calculating BCRs for buildings it might yet retrofit).[1035] SCE also notes that its 2026 RAMP analysis excludes facilities in tranche 4, consisting of its transmission and distribution structures, "due to various limitations and the complexity and extent of the computational task posed."[1036]

Observations and Findings

SPD has no observations or findings on the exposure.

Tranches

SCE departs from the default quintile tranching methodology for this risk. Instead, it tranches risk to facilitate prioritization of retrofit projects, classifying facilities into tranches by criticality.[1037] SCE states that it created this classification system prior to 2020 and used it in its 2022 RAMP.[1038] In both its 2022 RAMP and the present RAMP analysis, SCE only considers the top three tranches, leaving aside tranche 4, which

[1032] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 63.

[1033] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 63.

[1034] SCE 2026 RAMP Ch. 11, Figure II-3 "Risk Bowtie for Seismic Risk," p. 15.

[1035] SCE 2026 RAMP Ch. 11, p. 14.

[1036] SCE 2026 RAMP Ch. 11, p. 14, footnote 29.

[1037] SCE 2026 RAMP Ch. 11, pp. 13-14.

[1038] SCE 2026 RAMP Ch. 11, p. 14.

includes "transmission corridors, lattice towers, the distribution system, poles, and meters."[1039] Figure 8-2 shows SCE's approach to classifying facilities into tranches by criticality, separating facilities into tranche 1, "most critical assets" (e.g., highly occupied buildings and emergency operations centers), tranche 2, "next most critical assets" (e.g., switching centers and service centers), tranche 3, "highly important assets" (e.g., redundant communications facilities and distribution substations), and tranche 4, "remaining critical infrastructure" (described above). [1040] SCE notes it has adjusted the scope for inclusion in different tranches "on the basis of new knowledge gained by screening and assessing more assets as part of RAMP scope."[1041]

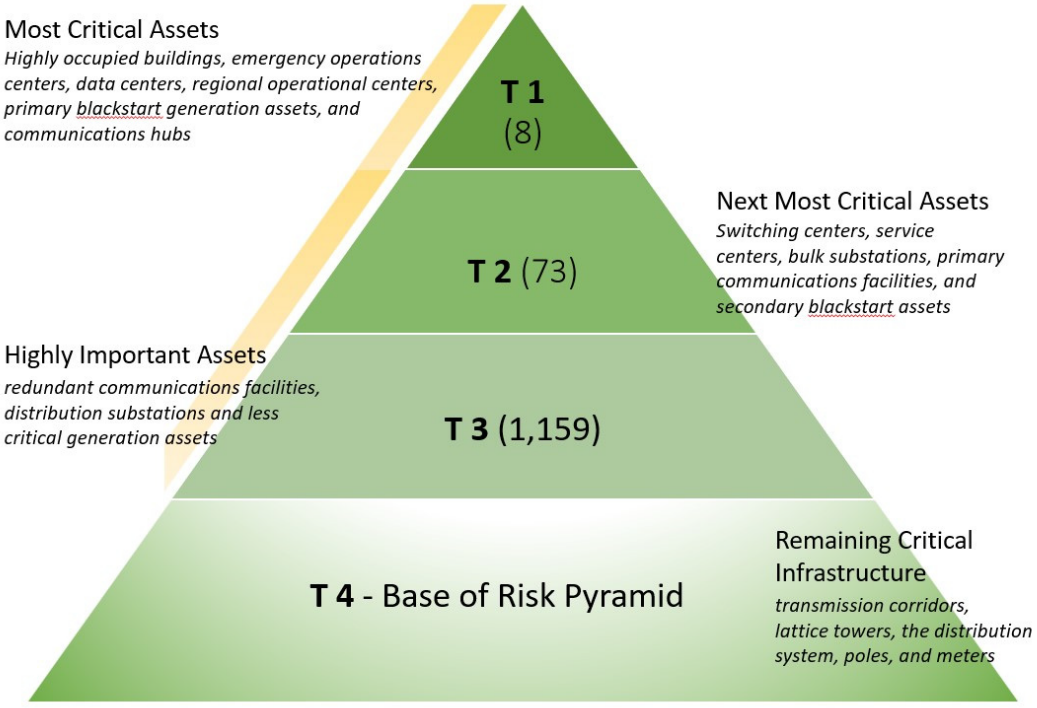


Figure 8-2. SCE Seismic Resiliency Pyramid: Tranches 1 through 4.[1042]

SCE notes that its tranching approach combines safety and reliability risk values.[1043] Table 8-2 describes the top three tranches SCE includes in its RAMP scope for seismic risk in terms of the number of assets, pre-

[1039] SCE 2026 RAMP Ch. 11, Figure II-2 "SCE Seismic Resiliency Pyramid (Tranches; T 1-4)," p. 14.

[1040] SCE 2026 RAMP Ch. 11, Figure II-2 "SCE Seismic Resiliency Pyramid (Tranches; T 1-4)," p. 14.

[1041] SCE 2026 RAMP Ch. 11, p. 13.

[1042] SCE 2026 RAMP Ch. 11, Figure II-2 "SCE Seismic Resiliency Pyramid (Tranches; T 1-4)," p. 14.

[1043] SCE 2026 RAMP Ch. 11, p. 18.

mitigation risk score, and post-mitigation risk score per tranche. The pre- and post-mitigation risk scores encompass safety, reliability, and financial risk values.

Table 8-2. SCE's Seismic Tranches, Number of Assets and Pre- and Post-Mitigation Risk Scores ($000s)[1044]

Tranche	Number of Assets	Pre-Mitigation Risk Score	Post-Mitigation Risk Score
T1	8	$475,509	$267,682
T2	73	$27,630	$12,955
T3	1,159	$416,703	$441,706
Total	1,240	$919,842	$722,343

SCE explains the rationale behind its tranching approach: SCE's approach to tranching, placing its most critical assets at the top, makes sense "because earthquake risk is non-linear. That is, damage in tranches 1 and 2 dominates system performance. Hardening them first delivers the largest reduction in expected consequence, even if seismic event probability is inherently uncertain."[1045] SCE also notes that its approach to tranching seismic risk "is a practical utility implementation of NIST Special Publication 1310 (2024) as well as long-standing earthquake engineering and seismic resiliency principles, as originally stated in Technical Council on Lifeline Earthquake Engineering (TCLEE) guidance and other documents.[1046, 1047]

Observations and Findings

SPD observes that SCE's approach to tranching seismic risk is more appropriate than the quintile approach, preferred under the Risk-Based Decision-Making Framework (RDF) approach to tranching, which is based on likelihood of a risk event (LoRE) and consequence of a risk event, both of which are highly uncertain for seismic risk events.

[1044] SCE 2026 RAMP, Ch. 11, Table II-3 "SCE's Seismic Tranches, Number of Assets, and Pre-and-Post Risk Scores," p. 19. Here, SPD understands "pre-and-post" to mean pre-mitigation and post-mitigation (i.e., 2029 and 2032).

[1045] SCE 2026 RAMP, Ch. 11, p. 19.

[1046] National Institute of Standards and Technology (NIST) Special Publication 1310: Initial Framework to Design Lifeline Infrastructure for Post-earthquake Functional Recovery, Volume 1 (2024) (https://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.1310.pdf, accessed Oct. 5, 2026).

[1047] SCE 2026 RAMP, Ch. 11, p. 19.

However, SPD also notes that tranche 3 is substantially larger than the first two tranches and may lack the granularity needed to prioritize retrofitting and other mitigations. SCE notes that many tranche 3 assets have not yet been field-screened, saying, "More work is still needed to continue using FEMA P-154 and E-74,"[1048] and adding, "Until the screening process [for all SCE facilities] can be completed, it seems too early in the process to confidently add complexity to the tranche system developed for the 2022 RAMP. In the next RAMP, perhaps it would make sense to break apart tranche 3 and add more tranches, but we are not at that juncture now."[1049]

SPD observes that tranche 3, in addition to being far larger than the first two tranches, is also far more diverse. Further, SPD observes that SCE estimates that post-mitigation risk will be greater than pre-mitigation risk going from $416.7 million at the beginning of 2029 to $441.7 million by the end of 2032, while SCE estimates post-mitigation risk to go down for the first two tranches.[1050] Based on these observations, SPD finds that SCE has not demonstrated that tranche 3 is sufficiently granular or homogeneous for the purpose of seismic risk mitigation prioritization.

SPD also observes that SCE has not adequately justified excluding tranche 4 from its quantitative seismic risk analysis. Per a 2011 article about the Christchurch earthquakes in New Zealand, assets like those found in SCE's tranche 4 can contribute to extended service interruption after an earthquake, given that the earthquake of February 22, 2011, damaged 50 percent of 66 kilovolt (kV) cables (30 kilometers [km] out of a total of 60 km) and 15 percent of 11 kV cables damaged (330 km out of a total of 2,200 km). In the ten days it took to restore power, ratepayers experienced 629 million customer minutes interrupted.[1051] SPD believes 66 and 11 kV cables might be considered part of SCE's tranche 4 as part of "transmission corridors" and "the distribution system."[1052] This 2011 article suggests that SCE should include tranche 4 assets in its seismic risk evaluation.

SPD further observes that, although SCE cites modeling limitations and computational complexity as a barrier to evaluating tranche 4 assets, a 2018 SCE-associated technical paper states that SCE's System Earthquake Risk Assessment (SERA) model at that time included "a database of about 40,000 substation

---

[1048] "Structural and Non-Structural Assessment Standards (American Society of Civil Engineers [ASCE] 41, FEMA P-154, FEMA P-58, FEMA E-74): Engineering guidelines and screening tools for evaluating building and equipment vulnerability. Performance-based engineering standards are applied in support of prioritizing projects, using a system that takes into account safety and reliability factors" per SCE 2026 RAMP, Ch. 11, p. 9.

[1049] SCE 2026 RAMP, Ch. 11, p. 49.

[1050] SCE 2026 RAMP, Ch. 11, Table II-3 "SCE's Seismic Tranches, Number of Assets, and Pre-and-Post Risk Scores," p. 19.

[1051] Andrew Massie (Christchurch Polytechnic Institute of Technology) and Neville R. Watson (University of Canterbury, Christchurch), Impact of the Christchurch Earthquakes on the Electrical Power System Infrastructure (December 2011), Bulletin of the New Zealand Society for Earthquake Engineering 44(4), p. 425 (https://www.researchgate.net/publication/265888525_Impact_of_the_Christchurch_earthquakes_on_the_electrical_power_system_infrastructure, accessed Oct. 5, 2026).

[1052] SCE 2026 RAMP Ch. 11, Figure II-2 "SCE Seismic Resiliency Pyramid (Tranches; T 1-4)," p. 14.

components, including essentially every piece of equipment at every 500 kV and 220 kV substation, and most of the equipment at 115 kV and 66 kV substations; every transmission tower; every distribution feeder," and included an evaluation of every component's "likely performance in any of 50 possible future scenario earthquakes, including forecasts of system-wide damage, repair efforts and outage times." [1053] This 2018 article suggests there should be a way to conduct a quantitative seismic risk analysis of SCE's tranche 4 assets.

Based on these observations, SPD finds that SCE's lack of any evaluation of seismic risk to tranche 4 assets leaves a substantial amount of risk out of its assessment; SPD also questions how infeasible it would be to assess the risk to these assets.

Risk Reporting Units (RRUs)

SCE did not define RRUs for this risk.

Observations and Findings

The definition of RRUs from the RDF Phase 4 Decision specifies that RRUs are a "CPUC jurisdictional effort within Electric Operations or Gas Operations…."[1054] The RDF requirements specify that utilities define an RRU for each mitigation, with some exemptions.[1055] Risk mitigation categories that the Phase 4 Decision exempted from needing RRUs to be defined are PSPS and protective equipment device settings.[1056] Other than these, the Phase 4 Decision required SCE to define RRUs for mitigation programs costing $10 million or more. For the purposes of this report, SPD is interpreting the $10 million threshold to pertain to the cost of the mitigation program over the course of the four-year RAMP cycle.[1057]

In its proposed plan, SCE reports that four of its six seismic risk controls exceed the $10 million threshold, and two of these may be considered part of electric operations:[1058]

[1053] John Eidinger (G&E Engineering Systems, Inc.) and John Dai (Southern California Edison) et al., Evolution of Electrical Grid Seismic Resiliency (2018), p. 9 (https://www.geengineeringsystems.com/ewExternalFiles/Eidinger%20Dai%20Grid%20Resiliency.pdf, accessed Oct. 5, 2026).

[1054] D.25-08-032, Appendix A, p. A-7.

[1055] D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[1056] "The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following: 1. Public Safety Power Shutoffs; 2. Protective Equipment Device Settings; 3. Mitigation and Control Programs that do not meet the following thresholds: a. For PG&E and SCE, $10 million…" from D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[1057] D.25-08-032, p. 67 ("establishing a cost threshold for mitigation and control programs based on the same thresholds found in the Phase 1 Decision…"), which in turn points to the RDF Phase 1 Decision, D.21-11-009, p. 141, where the cost threshold is described as "the aggregate cost over the upcoming GRC funding period."

[1058] SCE 2026 RAMP Ch. 11, Table VI-9 "BCR Values for Proposed Controls," p. 35.

- Seismic Building Safety Program - Electric (C1), with a full cycle cost of $61,409,000.
- Seismic Building Safety Program - Generation (C3), with a full cycle cost of $17,101,000.

SPD notes that neither program falls under the categories of PSPS or protective equipment device settings.

In response to an SPD data request about its decision not to define RRUs for any seismic risk controls, SCE clarified that it considered its seismic risk controls to be outside the RRU requirement because seismic risk "is characterized as an exogenous hazard driven by geologic conditions rather than utility operational drivers," and as such cannot "be meaningfully disaggregated into discrete, repeatable, asset- or location-based units," thus creating RRUs for this risk "would not meaningfully enhance transparency or comparability" of risk mitigation programs.[1059]

SPD observes that SCE's rationale focuses on the exogenous nature of seismic hazard rather than whether a control could be disaggregated into meaningful reporting units. SPD finds, for example, that the Seismic Building Safety Program - Electric (C1) could be disaggregated into meaningful reporting units. C1 is an electric-system control that appears to fall within electric operations, exceeds the $10 million threshold, and consists of discrete asset- and location-based retrofit work, indicating that SCE may be able to further disaggregate the assets that fall within this control to improve traceability of scope, costs, work units, timing, and risk reduction.

Risk Drivers

In its risk bow tie, SCE presents one potential leading indicator for this risk, or driver: peak ground acceleration of 0.05 g or greater. SPD discusses SCE's selection of this threshold value under Risk Description.

Observations and Findings

SPD observes that additional drivers that SCE might consider including in its risk bow tie for seismic risk are construction and design standards used for critical infrastructure that are outdated or lack sufficient safety margins (perhaps negligent of critical safety factors) and/or are otherwise unsafe in earthquake-prone regions.

Risk Driver Frequencies

The Chapter 11 seismic risk work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness" discusses how SCE calculated the frequency of the seismic risk driver, peak ground acceleration of 0.05 g or greater. SCE states that it calculated the average frequency at which a building in a given tranche will experience "strong motion" (i.e., peak ground acceleration of 0.05 g or

[1059] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 65.

greater) "in the next 5 years or so" for each of 532 buildings that SCE screened "with EROVER (an electronic field data-collection instrument—an app—that encodes the level-2 FEMA P-154 rapid visual screening protocol)."[1060] SCE clarifies in its work paper that "strong motion" does not mean "damaging motion," but rather a level "above which damage commonly occurs," such as loose items falling.[1061] SCE incorporated into its model the most recent California USGS soil data in addition to its "most recent and authoritative model of earthquake fault locations, possible magnitudes, and activity rates."[1062] Additionally, SCE states that it included "the engineering seismology community's" current understanding of the relationships between "earthquake magnitude, distance, site conditions, and shaking," referring to a community convened by the Statewide California Earthquake Center.[1063]

Based on the above, SCE estimates that, on average, "an SCE building" experiences this level of shaking about 0.12 times per year, or roughly once every eight years, while stating that consequences and risk estimates will rise as additional buildings are screened.[1064] SCE's model estimates slight variations in expected frequency of the triggering event depending on tranche (ranging from 0.11 to 0.15), shown below with estimated consequences in Table 8-3.[1065]

[1060] SCE 2026 RAMP Ch. 11 work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness," p. WP-1.

[1061] SCE 2026 RAMP Ch. 11 work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness," p. WP-1.

[1062] SCE 2026 RAMP Ch. 11 work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness," p. WP-1.

[1063] SCE 2026 RAMP Ch. 11 work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness," p. WP-1.

[1064] SCE 2026 RAMP Ch. 11 work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness," p. WP-1.

[1065] SCE 2026 RAMP Ch. 11 work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness," p. WP-1.

Table 8-3. Seismic Driver Frequency and Consequences Per Event (PGA ≥ 0.05 g) for Screened SCE Buildings[1066]

Tranche	Building Count	Frequency per year	Financial (million)	Injuries	Fatalities	Reliability (CMI)
Unknown	70	0.11	$10.8	2.6	0.07	0
T1	14	0.15	$12.9	1.8	0.08	0
T2	71	0.14	$6.0	1.3	0.11	1.13×10^9
T3	377	0.12	$53.4	8.2	0.60	0.47×10^9
Total	532	0.12	$84.8	16.0	0.89	$1.60. \times 10^9$

Observations and Findings

SPD observes that the tranche-level values SCE reports in its work paper's Table 1 "Earthquake driver frequency, consequences, and mitigation effectiveness for screened SCE buildings" do not sum to the totals SCE reports in the same table. By SPD's calculation, the financial values sum to $83.1 million, rather than $84.8 million, while the injury and fatality values sum to 13.9 and 0.86, rather than 16.0 and 0.89, respectively.

Consequences

As noted above, SCE states that it has refined its seismic consequence modeling by using updated tools, including OpenSHA and CHaT, to support more detailed and larger-scale earthquake modeling. Also noted above, SCE has simplified its estimated seismic event outcomes by grouping different magnitudes of shaking into shaking greater than or equal to 0.05 g at one or more SCE facilities or critical facilities (specifying facilities in tranches 1, 2, or 3).

SCE explains that this revised approach better reflects variability in earthquake sources.[1067] For example, SCE notes that there is a "high concentration of seismic risk" in the Los Angeles Basin, and small, local seismic events can have "significant impacts," while larger, more distant seismic events may have "only minor impacts." [1068]

[1066] SCE 2026 RAMP Ch. 11 work paper "WP Ch 11 Earthquake Driver Frequency, Consequences, and Mitigation Effectiveness," Table 1 "Earthquake driver frequency, consequences, and mitigation effectiveness for screened SCE buildings," p. WP-1.

[1067] SCE 2026 RAMP Ch. 11, p. 18.

[1068] SCE 2026 RAMP Ch. 11, p. 18.

Observations and Findings

SPD observes that SCE has not demonstrated that it has benchmarked the safety, reliability, and financial consequences estimated by its probabilistic seismic risk model against observed earthquake performance. In response to a data request, SCE stated that it does not produce a Northridge-specific[1069] estimate of the consequence of a risk event (CoRE) and that historical data are not maintained in a form that permits comprehensive calibration or validation of the current model.[1070] However, as noted above, an SCE-associated technical paper provides event-specific information on damaged facilities and equipment, customer interruptions and restoration milestones, and asset-level repair work following the Northridge earthquake.[1071] Although these data may not support comprehensive calibration of the current model, SPD observes that they appear sufficient for a high-level hindcast or reasonableness check comparing modeled consequences with historical data. As such, SPD finds that SCE has not demonstrated that it has benchmarked its model's estimated consequences against observed earthquake performance to the extent possible.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[1072]

In its 2026 RAMP, SCE identifies six seismic risk controls[1073] and no mitigations.[1074] The six risk controls include:

- Seismic Building Safety Program – Electric (C1): seismic retrofits and hardening for substations, MEER buildings, substation equipment, and critical transmission tower foundations.

[1069] "Northridge-specific" refers to the magnitude 6.7 that took place in Northridge, California, in the Los Angeles area, on January 17, 1994. For more information see the USGS web page Historic Earthquakes: Northridge, California (https://web.archive.org/web/20161201081744/https://earthquake.usgs.gov/earthquakes/states/events/1994_01_17.php, accessed Oct. 6, 2026).

[1070] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 68(a-b).

[1071] John Eidinger (G&E Engineering Systems, Inc.) and John Dai (Southern California Edison) et al., Evolution of Electrical Grid Seismic Resiliency (2018), pp. 5-7 (https://www.geengineeringsystems.com/ewExternalFiles/Eidinger%20Dai%20Grid%20Resiliency.pdf, accessed Oct. 5, 2026).

[1072] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[1073] SCE 2026 RAMP Ch. 11, Table III-4 "Inventory of Seismic Risk Controls," p. 22.

[1074] SCE 2026 RAMP Ch. 11, p. 31.

- Seismic Building Safety Program – Information Technology (IT)/ Telecommunications (C2): bracing, anchoring, and rack replacement for IT and communications equipment to support operational continuity.
- Seismic Building Safety Program – Generation (C3): seismic improvements for utility-owned generation assets that may be needed for system restoration.
- Facility Emergency Management Program (C4): emergency preparedness, training, exercises, supplies, situational awareness, and response coordination.
- Seismic Building Safety Program – Non-Electric (C5): structural and non-structural retrofits for occupied and administrative buildings to reduce injury, fatality, and operational disruption risk.
- Seismic Building Safety Program – Emergency Communications (C6): seismic hardening of radio, antenna, equipment rack, and remote communications infrastructure to support post-earthquake restoration.

SCE included C1 through C4 in its 2022 RAMP; SCE is introducing C5 and C6 as new controls in its 2026 RAMP. All but one control falls under the Seismic Building Safety Program, which SCE describes as its broader Seismic Resiliency Program. SCE describes this program as being "designed to systematically assess, control, and mitigate [seismic] risks, aiming to reduce the likelihood and impact of earthquake-induced failures across all critical assets."[1075] SCE's controls are intended to reduce asset vulnerabilities, lower the likelihood or severity of earthquake-related equipment or facility damage, support life safety and operational continuity, and minimize the duration and extent of electrical disruptions following an earthquake.

As noted above, SCE is not proposing new mitigations; rather, it notes that any "new approaches tend to be unique solutions, or modifications or enhancements to the [listed] controls."[1076]

Observations and Findings

SPD observes that SCE's seismic controls generally align with the seismic risk, given that they focus on structural retrofits, equipment anchoring and bracing, emergency communications hardening, and emergency management activities intended to reduce asset vulnerability, equipment or facility damage, outage impacts, and restoration time following an earthquake.[1077]

[1075] SCE 2026 RAMP Ch. 11, p. 6.

[1076] SCE 2026 RAMP Ch. 11, p. 31.

[1077] SCE 2026 RAMP Ch. 11, pp. 21-31.

Alternatives Analysis

SCE provided two alternatives to its proposed plan. Both propose reducing activity and expenditures, resulting in less seismic risk mitigation, so SCE rejected both alternatives. The change from the proposed plan in the first alternative is removing from the scope of work for risk assessments and retrofits "areas of B-substations and Non-Electric, non-critical buildings."[1078] The second alternative would double the percent of these buildings removed from the scope of work, from a 25 percent reduction in the first alternative to a 50 percent reduction in the second.

Table 8-4 provides a comparison of SCE's estimated costs and benefit-cost ratios (BCRs) for its proposed plan and two alternatives.

Table 8-4. Seismic Control Program and Alternatives ($000s)[1079]

Plan	O&M	Capital	Total	BCR Societal	BCR WACC	BCR Hybrid
Proposed	$11,058	$248,333	$259,391	56.25	21.01	27.73
Alternative 1	$10,014	$217,789	$227,803	63.86	23.80	31.49
Alternative 2	$8,970	$187,246	$196,215	73.69	27.56	36.36

Observations and Findings

SPD observes that SCE's decision to select the proposed plan is reasonable, given the trade-offs in delays to risk assessments and retrofits.

SPD additionally observes that SCE's Tables VI-6[1080] and VI-8[1081] present duplicative information, both presenting risk scores by tranche whereas one is supposed to show risk scores by plan.

[1078] SCE 2026 RAMP Ch. 11, p. 42.

[1079] SCE 2026 RAMP Ch. 11, Table VI-7 "Seismic Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 34.

[1080] SCE 2026 RAMP Ch. 11, Table VI-6 "Seismic Proposed Plan and Alternative Plans Summary of Pre and Post LoRE and CoRE Risk Scores," p. 33.

[1081] SCE 2026 RAMP Ch. 11, Table VI-8 "Proposed Plan Pre- and Post-LoRE, CoRE Risk Scores ($000s) by Tranche," p. 34.

SPD also observes that, in response to SPD's 2022 RAMP recommendation that SCE evaluate programmatic alternatives rather than merely lower-spending versions of the same mitigation plan,[1082] SCE states that it found no international, federal, state, local, or other organizational guidance supporting materially different seismic mitigation programs.[1083] SCE maintains that structural and nonstructural retrofits including hardening switchyards, relay racks, and computer equipment racks remain the principal means of improving seismic resiliency.[1084] SCE nevertheless identifies earthquake early-warning technology integrated with SCADA systems as a potential future alternative and reported that it has conducted one pilot and considered another.[1085] However, SCE concludes that the technology is not yet sufficiently robust and that available vendor solutions are not mature enough for broad deployment.[1086] SPD recognizes the limitations SCE identified but notes that SCE should continue evaluating emerging seismic technologies and report the results of its pilot efforts in future RAMP filings.

BCR Calculations

SCE calculates BCR values for its six controls for seismic risk. SCE presents all BCRs, as required, under three discount rate scenarios: a weighted-average cost of capital (WACC) rate, a societal rate, and a hybrid rate.

Table 8-5 presents SCE's projected BCRs for the six controls in SCE's proposed plan for mitigating seismic risk. Figure 8-3 compares the BCRs for the six controls on a bar graph, highlighting the much higher BCRs SCE estimates for the Seismic Building Safety Program – Generation (C3).

[1082] From SPD's recommendations on Seismic Risk (Chapter 8), "Staff recommends proposing programmatic alternatives in future RAMP filings such as different mitigation programs," per 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 (Nov. 2022), p. 51 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/sce-2022-ramp-evaluation-report-final_111022.pdf, accessed Oct. 6, 2026).

[1083] SCE 2026 RAMP Ch. 11, p. 48.

[1084] SCE 2026 RAMP Ch. 11, p. 48.

[1085] SCE 2026 RAMP Ch. 11, p. 48.

[1086] SCE 2026 RAMP Ch. 11, p. 48.

Table 8-5. SCE's BCR Calculation for Seismic Risk (2029-2032) ($000s)[1087]

ID	Control	Operations and Maintenance (O&M)	Capital	Total	BCR Societal	BCR WACC	BCR Hybrid
C1	Seismic Building Safety Program – Electric		$61,409	$61,409	15.54	5.41	7.29
C2	Seismic Building Safety Program – IT/Telecom		$7,999	$7,999	21.06	7.44	9.77
C3	Seismic Building Safety Program – Generation		$17,101	$17,101	326.30	120.07	159.64
C4	Facility Emergency Management Program	$6,185		$6,185	72.97	66.84	73.75
C5	Seismic Building Safety Program – Non-Electric	$4,873	$138,783	$143,655	43.41	15.21	20.44
C6	Seismic Building Safety Program – Emergency Communications		$23,041	$23,041	35.79	12.49	16.23
	Total	$11,058	$248,333	$259,391	56.25	21.01	27.73

[1087] SCE 2026 RAMP Ch. 11, Table VI-9 "BCR Values for Proposed Controls," p. 35.

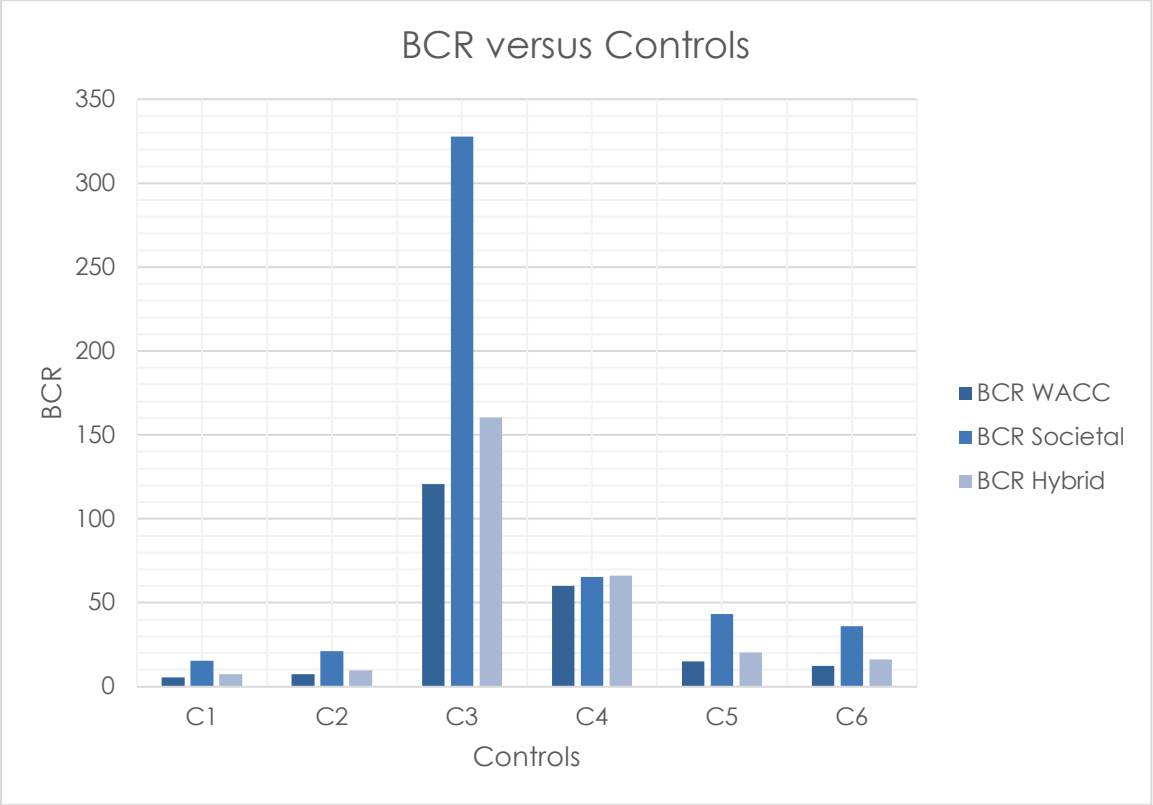


Figure 8-3. Seismic BCR versus Controls.[1088]

Observations and Findings

SPD observes that the BCRs for SCE's proposed seismic controls range widely from 5.41 to 326.30 across the controls, with Seismic Building Safety Program – Generation (C3) having a much higher set of BCRs than the other controls.

SPD further observes that the SCE's calculation of the total cycle cost for Seismic Building Safety Program – Non-Electric (C5) in its summary table do not reconcile with SPD's calculation of the total cycle cost for that program. SPD sums the O&M and capital costs to $143.656 million, rather than $143.655 million.[1089]

Summary of Findings

SPD finds that:

[1088] SCE 2026 RAMP Ch. 11, Table VI-9 "BCR Values for Proposed Controls," p. 35.

[1089] SCE 2026 RAMP Ch. 11, Table VI-9 "BCR Values for Proposed Controls," p. 35.

1. SCE's seismic bow tie diagram does not clearly distinguish between the risk driver, triggering event, and outcome, defining each identically.
2. SCE has not demonstrated that tranche 3 is sufficiently granular or homogeneous for purposes of seismic risk prioritization.
3. SCE has not adequately justified excluding tranche 4 assets from its quantitative seismic risk analysis: SCE's lack of any evaluation of seismic risk to tranche 4 assets leaves a substantial amount of risk out of its assessment. SPD also finds that there is evidence that earthquake damage to these asset classes can contribute significantly to service interruptions and that SCE may have the capability to evaluate transmission and distribution assets for seismic risk exposure.
4. SCE did not develop RRUs for C1, even though the control appears to fall within electric operations, exceeds the $10 million threshold, and consists of discrete asset- and location-based retrofit work that may be suitable for disaggregation into meaningful reporting units.
5. SCE has not demonstrated that it has benchmarked the safety, reliability, and financial consequences estimated by its probabilistic seismic risk model against observed earthquake performance. Available historical information appears sufficient to support a high-level hindcast or reasonableness check, for example in the case of the 1994 Northridge Earthquake.

Recommendations to Address Findings

SPD recommends that SCE:

1. Revise its seismic risk bow tie to identify physical damage to or loss of function of an SCE asset as the triggering event and to differentiate outcomes by the severity and extent of asset damage or service disruption.
2. Complete field screenings for tranche 3 assets and use the results to evaluate whether tranche 3 can be further refined into additional seismic risk tranches in its next RAMP application.
3. Incorporate tranche 4 into the next RAMP application's seismic risk analysis. If full modeling is not yet feasible, SCE should explain the specific technical and data limitations, assess whether its prior seismic modeling capabilities and underlying information could support the analysis, and provide an interim or partial quantitative assessment of tranche 4 risk exposure.
4. Evaluate C1 for the applicability of RRUs that disaggregate the control by asset group or location and, where RRUs can be defined, identify for those RRUs, the associated scope, work units, costs, timing, BCRs, and risk reduction.
5. Develop high-level CoRE estimates based on consequence data from the Northridge Earthquake and, where sufficient historical data are available, other suitable earthquake events or the closest modeled equivalents. SCE should compare the modeled safety, reliability, and financial consequences with observed asset damage, customer interruptions, repair costs, and restoration performance; explain material differences; and use the results to validate and, where appropriate, refine its seismic consequence model.

9. Physical Security

Risk Description

The Southern California Edison Company (SCE) defines physical security as "the systems, measures, and strategies used to safeguard people, facilities, and assets from physical threats."[1090] SCE defines the main risk event for this risk as compromise of physical security or an attack on personnel. SCE does not include within this risk acts occurring beyond the security property line of SCE facilities involving SCE assets, including incidents resulting from criminal activity. SCE further describes the acts considered in-scope and out-of-scope for the physical security Risk Assessment and Mitigation Phase (RAMP) chapter in Table II-2.[1091]

Observations and Findings

Safety Policy Division (SPD) has no observations or findings on SCE's description of physical security risk.

Risk Bow Tie

SCE presents the following risk bow tie for physical security risk:[1092]

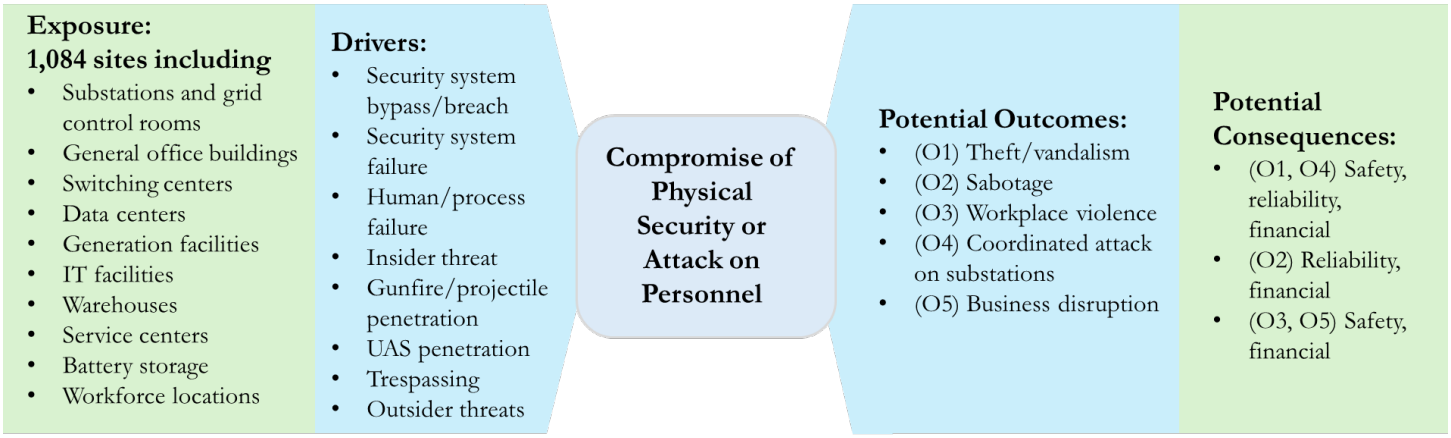


Figure 9-1. SPD Adaptation of SCE Physical Security Risk Bow Tie.[1093]

[1090] SCE 2026 RAMP Chapter 12 "Physical Security," p. 1.

[1091] SCE 2026 RAMP Ch. 12, Table II-2, "Physical Security RAMP Chapter Scope," p. 6.

[1092] SCE 2026 RAMP Ch. 12, p. 9.

[1093] SCE 2026 RAMP Ch. 12, Figure II-1 "Risk Bowtie for Physical Security Risk," p. 10.

Observations and Findings

SPD has no observations or findings on SCE's risk bow tie for physical security risk.

Exposure

SCE considers 1,048 sites in its physical security risk exposure.[1094] These sites include, but are not limited to: office buildings, substations, switching centers, grid control centers, data centers, laydown yards, generation facilities, IT facilities, warehouses, battery storage, and service centers.[1095]

Observations and Findings

SPD has no observations or findings on SCE's description of its exposure to physical security risk.

Tranches

SCE departs from the default quintile tranching methodology for this risk.[1096] First, SCE splits its facilities into tiers based on their criticality and specific building types, and for the 2026 RAMP SCE introduces a further layer of granularity, splitting these tiers into subdivisions of the transmission and generation tranches SCE used in its 2022 RAMP.[1097] SCE reports that this approach to risk tranching better captures the distinct risk profiles of its facilities and better aligns with the utility's existing risk mitigation framework and prioritization strategy.[1098]

Using this approach, SCE splits the scope of its physical security risk across five tranches: (1) Grid Operations (Tier 1-3); (2) Grid Operations (Tier 4-5); (3) Major Business Functions; (4) Generation Hydro; and (5) Generation General.[1099]

SCE describes its physical security tier classification system that underpins its approach to tranching in Figure II-2.[1100] Tiers 1-4 consist of transmission facilities and Tier 5 consists of distribution facilities.[1101] Tier

---

[1094] SCE 2026 RAMP Ch. 12, Figure II-1, p. 10; Table II-5 "Tranche Level Risk Exposure," p. 21.

[1095] SCE 2026 RAMP Ch. 12, p. 9.

[1096] SCE 2026 RAMP "Chapter 2 Risk Model and BRC [sic] Methodology Tranching Whitepaper," under "Major Physical Security," pp. 12-13.

[1097] SCE 2026 RAMP Ch. 2, work paper "Tranching Whitepaper," p. 13.

[1098] SCE 2026 RAMP Ch. 2, work paper "Tranching Whitepaper," p. 13.

[1099] SCE 2026 RAMP Ch. 12, p. 19.

[1100] SCE 2026 RAMP Ch. 12, Figure II-2 "Physical Security Tier System," p. 20.

[1101] SCE 2026 RAMP Ch. 12, p. 19.

1 critical facilities are transmission-level substations SCE identifies based on the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standard CIP-014 and Tier 2-5 facilities are assigned to a tier based on SCE's System Planning and Engineering annual report.[1102] SCE reevaluates the tier assignments of its facilities annually and may change a facility's tier based on a change in substation characteristics, such as forecasted load or number of transmission lines.[1103]

Observations and Findings

SPD has no observations or findings on SCE's approach to physical security risk tranching.

Risk Reporting Units (RRUs)

SCE does not define RRUs for its physical security mitigations or controls.

Observations and Findings

The Risk-Based Decision-Making Framework (RDF) Phase 4 Decision requires that utilities define an RRU for each mitigation, with some exemptions.[1104] Risk mitigation categories that the Phase 4 Decision exempted from needing RRUs defined are Public Safety Power Shutoff (PSPS) and protective equipment device settings.[1105] Other than these, the Phase 4 Decision required SCE to define RRUs for mitigation programs costing $10 million or more. For the purposes of this report, SPD is interpreting the $10 million threshold to pertain to the cost of the mitigation program over the course of the four-year RAMP cycle.[1106]

In its proposed plan, SCE reports several programs that exceed the $10 million threshold and do not fall under the categories of PSPS or protective equipment device settings:[1107]

- Protection of Grid Operations (Tier 1-3) (C1A), with a full cycle cost of $158.279 million.
- Protection of Grid Operations (Tier 4-5) (C1B), with a full cycle cost of $68.918 million.

[1102] SCE 2026 RAMP Ch. 12, p. 19.

[1103] SCE 2026 RAMP Ch. 12, p. 20.

[1104] D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[1105] "The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following: 1. Public Safety Power Shutoffs; 2. Protective Equipment Device Settings; 3. Mitigation and Control Programs that do not meet the following thresholds: a. For PG&E and SCE, $10 million…" from D.25-08-032, Appendix A, Row 15.1, pp. A-16-A-17.

[1106] D.25-08-032, p. 67 ("establishing a cost threshold for mitigation and control programs based on the same thresholds found in the Phase 1 Decision…"), which in turn points to the RDF Phase 1 Decision, D.21-11-009, p. 141, where the cost threshold is described as "the aggregate cost over the upcoming GRC funding period."

[1107] SCE 2026 RAMP Ch. 12, Table VII-11 "BCR Values for Proposed Plan Controls," p. 46.

- Protection of Generation – General (C2B), with a full cycle cost of $13.307 million.
- Protection of Major Business Functions (C3), with a full cycle cost of $111.324 million.
- Asset Protection (C4), with a full cycle cost of $139.127 million.

The definition of RRUs from the RDF Phase 4 Decision, specifies that RRUs are a "CPUC jurisdictional effort within Electric Operations and Gas Operations…."[1108] These five controls appear to be connected to electric operations.

However, SCE does not provide RRUs or an explanation of why it does not provide RRUs for those programs.

Risk Drivers

In its risk bow tie, SCE presents eight potential leading indicators for this risk, or drivers. They are: security system bypass/breach (D1), security system failure (D2), human/process failure (D3), insider threat (D4), gunfire/projectile penetration (D5), unmanned aerial system (UAS) penetration (D6), trespassing (D7), and outsider threats (D8).[1109]

Observations and Findings

SPD has no observations or findings on SCE's physical security risk drivers.

Consequences

SCE identified five potential outcomes of an adverse physical security event: theft/vandalism (O1), sabotage (O2), workplace violence (O3), coordinated substations attack (O4), and business disruption (O5).[1110] These outcomes variously impact the utility's safety, reliability, and financial risk.

Observations and Findings

SPD has no observations or findings on SCE's physical security risk event outcomes or consequences.

[1108] D.25-08-032, Appendix A, p. A-7.

[1109] SCE 2026 RAMP Ch. 12, p. 10.

[1110] SCE 2026 RAMP Ch. 12, p. 16.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[1111]

SCE identifies its physical security risk controls in Table IV-6.[1112] Table IV-6 also indicates if the control was included in SCE's 2022 RAMP and whether SCE includes it in its 2026 proposed or alternative plans.[1113] The nine controls in the Table IV-6 inventory are all included in SCE's proposed plan and alternative plans, and the one mitigation in the table, advanced technology (AI & robotics), is included in one of SCE's alternative plans.

Observations and Findings

SPD has no observations or findings on SCE's controls and mitigations for physical security risk.

Alternatives Analysis

SCE developed two alternative plans. Alterative Plan 1 contains the same controls as SCE's proposed plan, but would rely less on uniformed security officers and more on modern and advanced autonomous and remote-controlled security technology (e.g., drones and robotic platforms) to monitor SCE's facilities.[1114] Alternative Plan 2 would likewise use the same controls as the proposed plan, but expand the scope and level of deployment to include a larger number of facilities and deploying the full set of controls across SCE's service territory instead of a tailed suite of controls based on risk exposure for each facility.[1115]

SCE did not select Alternative Plan 1 due to the current uncertainty of deploying newer security technology that is unproven and potentially unreliable, potential exposure to new vulnerabilities (e.g., remote disabling or hacking autonomous devices), and the additional operations and maintenance burden, requiring SCE to hire and train staff to operate and maintain the newer technology.[1116]

[1111] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[1112] SCE 2026 RAMP Ch. 12, Table IV-6 "Inventory of Physical Security Risk Controls," p. 24.

[1113] SCE 2026 RAMP Ch. 12, p. 23.

[1114] SCE 2026 RAMP Ch. 12, p. 50.

[1115] SCE 2026 RAMP Ch. 12, pp. 53-54.

[1116] SCE 2026 RAMP Ch. 12, pp. 51-52.

SCE did not select Alternative Plan 2 due to the additional coordination and continued support it would require from multiple SCE departments and because it is the costliest of the plans.[1117]

Observations and Findings

Using the hybrid rate, the benefit-cost ratio (BCR) for both alternative plans is 0.16, while the proposed plan's BCR is slightly lower, at 0.15, and under all discount rates the BCRs for the three plans are nearly identical, so it appears feasibility and logistics are more important in the selection of the proposed plan than cost-effectiveness.[1118] The uncertainties of the two alternative plans are good reasons to reject them in favor of the more field-tested proposed plan.

BCR Calculations

SCE identifies its BCR values for its proposed plan in Table VII-11.[1119] The only proposed plan control programs with BCRs greater than 1.0 are Smart Key Program: Phase 1 – Electrical (C5) and Smart Key Program: Phase 2 - Non-Electrical (C6) (using the hybrid rate, respectively these BCRs are 2.29 and 1.7); the other control programs have BCRs between 0.0 and 0.33.[1120]

Observations and Findings

Based on the low or nonexistent BCRs for the proposed plan control programs, it is evident SCE does not select or prioritize physical security controls solely on cost-effectiveness.

Summary of Findings

1. SPD finds that SCE does not provide RRUs for its physical security control programs with a RAMP cycle cost of over $10 million and apparently related to electric operations, nor does it provide any explanation why it does not define RRUs.

[1117] SCE 2026 RAMP Ch. 12, pp. 54-55.

[1118] SCE 2026 RAMP Ch. 12, Table VII-9 "Physical Security Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032," p. 44.

[1119] SCE 2026 RAMP Ch. 12, Table VII-11 "BCR Values for Proposed Plan Controls," p. 46.

[1120] SCE 2026 RAMP Ch. 12, Table VII-11, p. 46.

Recommendations to Address Findings

1. SPD recommends SCE include in its next GRC cycle RRUs for its physical security control programs with a RAMP cycle cost of over $10 million or include an explanation of why the utility believes the RRU requirement does not apply.

10. Hydro Asset Failure Risk

Risk Description

The Southern California Edison Company (SCE) operates a portfolio of 81 hydro dams, which support 33 hydroelectric plants that provide a combined 1,153 megawatts (MW) of generating capacity. These dams are typically located in remote mountainous areas situated to capture high elevation rain and snowmelt. SCE generates electricity from the energy released as water flows downstream. Most of SCE's dams were constructed in the early 20th century, with the oldest dating to 1893 and the most recent constructed in 1986. SCE's dams account for around 4.5 percent of all electricity delivered to ratepayers. SCE defines the risk event for hydro assert failure as Uncontrolled Rapid Release of Water (URRW).[1121] SCE indicates that three risk drivers can lead to URRW:

- Seismic events/earthquake.
- Flood.
- Failure under normal operations.

SCE indicates that these events lead to the following outcomes:

- Inundation of unpopulated areas.
- Inundation of populated areas.
- Cascading inundation event.

SCE estimates the likelihood of a risk event leading to one of the failure outcomes at one event every 226 years for an annual probability of 0.00442.

SCE follows operational and risk management rules and regulations from the Federal Energy Commission (FERC) and California Department of Water Resources Division of Safety of Dams (DSOD). It uses the risk evaluation framework from the U.S. Bureau of Reclamation.

Observations and Findings

SCE plans to spend around $125 million on risk mitigations over 2029-2032. This is nearly a fivefold increase from the estimate SCE presented in its 2022 Risk Assessment and Mitigation Phase (RAMP) application. This difference in spending stems from a greater number of spillway improvements and an aggressive program of instrumentation upgrades.

Overall, SCE provides a good description and account of its hydropower risks. SCE indicates that it models its risk assessment and other safety practices on federal risk guidelines and guidance from the California

[1121] SCE 2026 RAMP, Chapter 13 "Hydro Asset Failure," p. 2.

DSOD.[1122] However, SCE's RAMP application contains numerous errors and missing tables. SCE has provided corrections and data that it omitted from its RAMP application through responses to data requests from Safety Policy Division (SPD).

Risk Bow Tie

SCE presents the following risk bow tie for hydro asset failure risk:

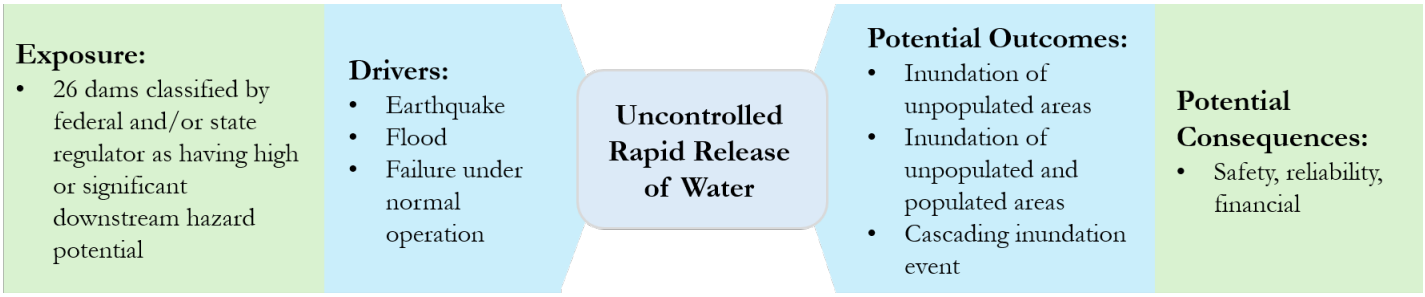


Figure 10-4. SPD Adaptation of SCE Hydro Asset Failure Risk Bow Tie.[1123]

Observations and Findings

SCE's risk bow tie shows all required elements. However, both the risk bow tie and the probability SCE assigns to the triggering event (URRW) are at odds with SCE's Table I-1 "Hydro Asset Failure Proposed Plan Summary of Pre and Post LoRE and CoRE Risk Scores" ("LoRE" being the likelihood of a risk event and "CoRE" being the consequence of a risk event), which lists the pre-mitigation likelihood as 3.67E-03 (0.00367), which SPD calculates is a likelihood of 1 failure event in 272 years.[1124] Elsewhere in Chapter 13 (p. 4), SCE states "[t]he likelihood any of these associated outcomes occurring at one of SCE's 26 high-hazard dams is estimated to be one failure every 226 years" and in SCE's risk bow tie (p. 15), SCE gives the likelihood of URRW as "0.00442 / yr (1 in 226)." In response to a data request, SCE explained that this discrepancy arises because the likelihood reported in Table I-1 represents the pre-mitigation risk in the year 2029; the likelihood in SCE's risk bow tie describes current conditions.[1125] By 2029, SCE expects to reduce the likelihood to a pre-mitigation risk of 3.67E-03 (0.00367).[1126]

[1122] SCE 2026 RAMP Ch. 13, p. 8 and p. 12.

[1123] SCE 2026 RAMP Ch. 13, Figure II-3 "Hydro Asset Failure Risk Bowtie," p. 15.

[1124] SCE 2026 RAMP Ch. 13, Table I-1 "Hydro Asset Failure Proposed Plan Summary of Pre and Post LoRE and CoRE Risk Scores," p. 7.

[1125] SCE response to Data Request SPD-SCE-2026RAMP-007, Question 1.

[1126] SCE 2026 RAMP Ch. 13, Table I-1 "Hydro Asset Failure Proposed Plan Summary of Pre and Post LoRE and CoRE Risk Scores," p. 7.

Exposure

SCE defines its hydro asset failure exposure as "26 dams classified by federal and/or state regulator as having High or Significant Downstream Hazard Potential."[1127] This refers to the 26 dams classified as "significant hazard" or higher by FERC and the DSOD that SCE operates. SCE designated these dams as "high hazard." In 2026, the average age of SCE's dams is 96 years. SCE's high-hazard dams are all located in the Sierra Nevada Mountains except for a reservoir situated on Catalina Island. In SCE's 2022 RAMP, SCE operated one additional high hazard dam, the Kern River Diversion 1 hydroelectric project, that SCE has since reclassified as low hazard.[1128] See Figure 13-2 for a map of dams operated by SCE and their risk levels.

[1127] SCE 2026 RAMP Ch. 13, Figure II-3 "Hydro Asset Failure Risk Bowtie," p. 15.

[1128] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 77.

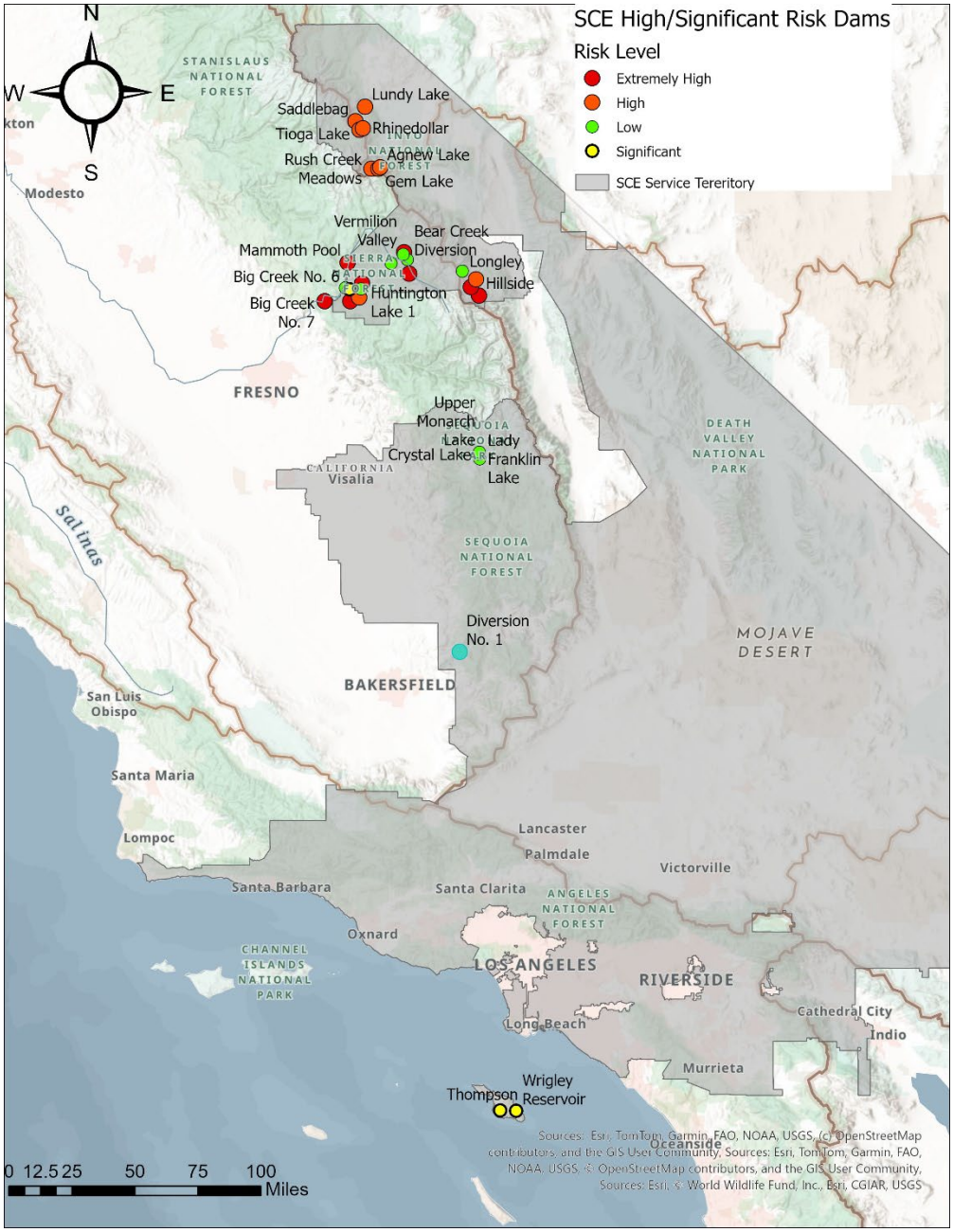


Figure 10-5. Dams Operated by SCE.[1129]

[1129] Dataset i17 California Jurisdictional Dams, California Open Data Portal (https://data.ca.gov/dataset/i17-california-jurisdictional-dams, accessed June 11, 2026).

Observations and Findings

SPD has no observations or findings on the exposure.

Tranches

SCE departs from the default quintile tranching methodology for this risk.[1130]

SCE changed its tranching methods from its 2022 RAMP in response to changes to the California Public Utilities Commission's (CPUC's or Commission's) Risk-Based Decision-Making Framework (RDF). Previously, SCE grouped its dams into four groups based on location, height, size, and construction type. The RDF Phase 2 Decision (Dec. 2022)[1131] required the creation of risk tranches and also required the asset or system in each tranche to have homogeneous risk profiles which can be treated with similar mitigations. The RDF Phase 3 Decision (June 2024) added the recommendation of grouping assets into quintiles based on risk.[1132] In SCE's Tranching White Paper, SCE made the case that its dams have distinct risk profiles given their unique combinations of construction methods, materials, and geographic location, arguing that each dam comprised its own risk tranche.[1133]

Observations and Findings

The small number of dams belonging to SCE do not cluster into any easily discernable grouping for the purposes of risk mitigation. The Phase 3 RDF Decision gives utilities permission to use alternative tranching methods.[1134] Because each dam has differing risk characteristics, placing each dam into its own tranche appears reasonable.

[1130] See SCE 2026 RAMP "Chapter 2 Risk Model and BRC [sic] Methodology Tranching Whitepaper," for more information. SCE initially submitted this white paper November 3, 2025; SCE updated the white paper and submitted it as a work paper for its RAMP Chapter 2 on May 27, 2026.

[1131] D.22-12-027, Appendix A, Row 14, p. A-13.

[1132] D.24-05-064, Appendix A, Row 14, pp. A-13-A-14.

[1133] SCE 2026 RAMP Ch. 2 Risk Model and Benefit-Cost Ratio Methodology work paper "Tranching Whitepaper," p. WP-13-WP-14.

[1134] D.24-05-064, Appendix A, Row 14, pp. A-13-A-14.

Risk Reporting Units (RRUs)

As with their tranches, SCE notes that each dam is a unique asset with few characteristics in common. Thus, each mitigation and control is specific to the dam on which it is performed. For that reason, SCE classifies each mitigation as its own RRU.[1135]

Observations and Findings

Consistent with its tranching methodology, SCE assigns RRUs to individual dams and then to specific controls and mitigations. SCE's RRUs reflect the complex nature of dams. SCE has created appropriate RRUs for its hydropower facilities.

Risk Drivers

In its risk bow tie, SCE presents three potential leading indicators for this risk, or drivers:

- **Earthquake**: Many of SCE's dams in the Sierra Nevadas lie close to faults. Earthquakes may cause dams to settle and sink below the level of their reservoirs. They may also lead to cracking and loss of strength in concrete dams. Either situation can cause URRW and may compromise dam operations.
- **Flood**: Heavy precipitation and rapid snowmelt may cause reservoir levels to rise quickly. Although dams have spillways and other measures to deal with these events, extreme conditions may cause erosion or otherwise damage spillways. Flooding may also erode dam foundations.
- **Failure under normal operations**: Dams may fail under normal conditions. This usually occurs due to a design flaw and tends to happen in the first few years of a dam's life. However, dams may also fail due to age and degradation over time.

Observations and Findings

Overall, SCE describes its risk drivers well in accordance with the Commission's RDF requirements. However, Safety Policy Division (SPD) had questions regarding the impact of drought on dam operations. At first glance, SCE does not appear to have considered drought impacts. Drought leads to lower reservoir levels. Lower reservoir levels could expose a dam's surface to cold air during winter months. This can create more severe freeze-thaw cycles leading to concrete degradation and cracking. SCE responded to SPD's questions with additional information on how it manages this concern.[1136] SCE reports that it carefully monitors its dam surfaces for damage and proactively maintains its dams in accordance with FERC and DSOD rules and practice. Moreover, SCE states that it regularly operates many of its dams at reduced reservoir levels. It has not found any extra risk due to lower water levels. Additionally, SCE submitted a

[1135] SCE 2026 RAMP Ch. 13, p. 24.

[1136] SCE response to Data Request SPD-SCE-2026RAMP-005, Questions 73 and 74.

Climate Pilot White Paper concurrently with its 2026 RAMP pursuant to the RDF Phase 3 Decision requirements.[1137] This white paper included a pilot study on climate change impacts, including drought, for the Vermillion Valley Dam.[1138] SCE found that drought poses little to no safety risk.[1139] In summary, SCE appears to have adequately considered the risk drivers potentially leading to failures in its hydroelectric facilities.

Risk Driver Frequencies[1140]

- **Earthquake**: SCE estimates the annual probability of an earthquake failure at 0.00147 or one in 700. This amounts to about a third of overall likelihood of failure.
- **Flood**: The estimated likelihood of flood failures stands at 0.00189 or about one in 500. Flooding accounts for about 43 percent of the total probability of failure.
- **Failure under normal operations**: SCE calculates the annual probability of failure for this driver at 0.00106 or about one in 900 years. This accounts for around 24 percent of the total probability of failure.

Observations and Findings

- **Earthquake:** SPD has no observations or findings on the risk driver frequencies for this risk.
- **Flood:** SCE draws from the International Commission on Large Dams (ICOLD) database[1141] to estimate the historical frequency of failures. SCE adjusts these values to account for the age and composition of their dams. SCE also holds workshops with regulatory agencies to examine its dams. However, a changing climate presents new risks as precipitation swings from drought to extreme precipitation events. The Vermillion Valley Dam case study in SCE's Climate Pilot White Paper analyzes the impact of increasing variability of precipitation on SCE's hydroelectric operations. The findings of this study appear to be applicable to many of SCE's other dams. In addition, SCE identified dams for further pilot studies. SPD expects these studies to help SCE develop a comprehensive approach to assessing risks to hydro assets from a changing climate.
- **Failure under normal operations:** SPD has no observations or findings on the risk driver frequencies for this risk.

[1137] D. 24-05-064, pp. 88-92.

[1138] SCE 2026 RAMP Ch. 2, Appendix A, Climate Pilot White Paper, pp. 10-11 and pp. 45-55.

[1139] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 74.

[1140] SCE 2026 RAMP Ch. 13, p. 15.

[1141] ICOLD World Register of Dams (https://www.icold-cigb.org/GB/world_register/world_register_of_dams.asp, accessed July 21, 2026).

Cross-Cutting Factors

Although not mentioned in SCE's RAMP application, sediment runoff from wildfires presents risks to dams. This risk comes in the form of sediment loading and from sediment filling in reservoirs.

Observations and Findings

As part of its Climate Pilot White Paper, SCE considered sediment runoff from wildfires.[1142] In this study SCE worked with state and federal agencies to assess debris risk and wildfire risk more generally.[1143] SCE notes that it did not consider wildfire risk on its own because fires and runoff on their own cannot directly cause a dam failure, rather runoff from wildfires contributes to other risks and estimating these effects is difficult due to lack of data. SCE actively monitors research in this area and revises its models as data become available.[1144] SCE also notes that the rocky, high-altitude terrain in which its dams sit presents only a minimal sedimentation risk.[1145]

SCE has considered wildfire impacts on its dam operations and keeps abreast of developments in understanding them as well as keeping track of changing conditions.

Consequences

As noted above, SCE defines the risk event for hydro assert failure as Uncontrolled Rapid Release of Water (URRW). SCE indicates that URRW consequences stem from three outcomes:

- **Inundation of unpopulated areas**: URRW will often lead to inundation of areas not continuously inhabited. This may include areas people frequent or in which people stay overnight such as campgrounds.
- **Inundation of unpopulated and populated areas**: A URRW may inundate a populated area as well as an unpopulated one depending on location and severity.
- **Cascading inundation event**: A large URRW may cause failures of downstream dams leading to cascading inundation events.

SCE reports that safety consequences consist of serious injuries and fatalities for all three outcomes. In terms of reliability, these outcomes all create the potential for local areas to become isolated from SCE's

[1142] SCE 2026 RAMP Ch. 2, Appendix A, Climate Pilot White Paper, p. 28, footnote 65; SCE response to Data Request SPD-SCE-2026RAMP-005, Question 71.

[1143] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 71.

[1144] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 71.

[1145] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 74.

power grid for long periods. SCE expects the financial consequences to comprise loss of generating capability, the cost of replacing power, and damage caused by inundation.

Observations and Findings

SCE lists a narrow set of consequences focusing on injury and fatalities while largely ignoring economic consequences of inundation. The Federal Emergency Management Agency (FEMA) guidance on dam failures advises operators to create a broad inventory of assets at risk from dam failure, including homes, schools, parks, infrastructure, and locations of cultural and recreational importance.[1146] FEMA then advises planners to identify economic, social, and environment impacts of dam failure. Economic impacts include direct and indirect impacts. Direct impacts occur immediately following failure of dams and generally consist of repair and rebuilding of damaged and destroyed structures. Indirect impacts consist of longer-term consequences such as unemployment and business closures.[1147]

By omitting economic impacts, SCE may be underestimating the consequences of dam failure. This may consequently lead SCE to underestimate mitigation benefits.

Controls and Mitigations

In its 2026 RAMP, SCE refers to a "control" as an activity that is or will be in place prior to the 2029 Test Year and is proposed for continuation; SCE refers to a "mitigation" as an activity that will begin in 2029 or later.[1148]

SCE presents six controls and four mitigations designed to reduce the likelihood and consequences of risk events. SCE includes two mitigations in its plans: SCE includes Dam Removal (M1) in its proposed plan and both alternative plans, and includes Dam Divestiture (M4) in its second alternative plan. Additionally, SCE discusses two mitigations that are not included in its proposed plan or either alternative plan: Relocation of Campgrounds (M2) and Purchase/Relocation of Inhabitable Structures (M3).

SCE also established two foundational activities, its Dam Safety Program (DSP) (F1) and external inspections by regulatory agencies (e.g., DSOD and USBR) (F2).[1149] Additionally, to comply with federal and state regulations, SCE performs two compliance activities, Hydro Operations (CM1) and Hydro Maintenance (CM2).

[1146] Federal Emergency Management Agency (FEMA), Assessing the Consequences of Dam Failure: A How-To Guide (2012) (FEMA Dam Failure), p. 2-1 (https://damsafety-prod.s3.amazonaws.com/s3fs-public/files/FEMA%20TM%20AssessingtheConsequencesofDamFailure%20March2012.pdf, accessed July 21, 2026).

[1147] FEMA Dam Failure, p. 2-2.

[1148] SCE 2026 RAMP, Section II "Executive Summary," p.4, footnote 4.

[1149] SCE 2026 RAMP Ch. 13, p. 25.

Dam Safety Program (F1)

SCE runs a comprehensive Dam Safety Program (DSP) which coordinates inspections by regulators and consultants, monitoring with instruments, proactive risk assessments, and the development of emergency action plans. While this activity does not directly impact risk drives, consequences, or outcomes, it does provide the foundation for all other controls and mitigations. SCE spends around $1.1 million annually on its DSP.

External Inspections (F2)

External entities regularly inspect SCE's dams to ensure they meet safety requirements mandated by law and regulation. FERC and DSOD inspect dams and may make recommendations for SCE to make repairs or undertake other actions. FERC also requires SCE's dams to undergo inspections from independent consultants. As with its DSP, SCE considers these external inspections to be foundational. These inspections do not directly affect risk drivers, consequences, or outcomes but provide the information and data that make all other controls and mitigations possible. SCE spends about $1.23 million annually on external inspections.

Hydro Operations (CM1)

Regulators require SCE to operate its hydroelectric facilities safely and reliably. This includes operating hydroelectric generating units, regulating water flows and reservoir levels plus maintaining situational awareness of the system through inspections and instrumentation. This control addresses Failure Under Normal Operations (D3). It does not directly impact outcomes or consequences.

Hydro Maintenance (CM2)

Regulators require SCE to keep its hydroelectric facilities in working order. These facilities include dams, canals, flumes, and other hydraulic infrastructures. Hydro maintenance consists of a set of inspections, repair, and remediation measures that keep all assets in safe working conditions. Emergency response also falls under this category. Hydro Maintenance addresses Failure Under Normal Conditions (D3). This control does not affect consequences and impacts; it only affects the likelihood of risk events.

In addition to the foundational activities and compliance activities described above, SCE implements the following controls and mitigations:

Seismic Retrofit (C1)

SCE retrofits its dams to better withstand seismic loads. SCE undertakes these retrofits when it detects structural deterioration in facilities or uncover design flaws which make dams susceptible to earthquake damage. Currently, three of SCE's dams operate under restricted reservoir levels due to seismic vulnerabilities. Seismic retrofits address the earthquake risk driver. This control does not reduce the likelihood of earthquakes, rather it reduces the likelihood that dams will suffer a failure event. SCE has scheduled one seismic retrofit project for completion in the 2029-2032 timeframe. This control does not directly affect outcomes or consequences.

Dam Surface Protection (C2)

Water seepage can degrade concrete dams by leaching away material and through repeated freeze-thaw cycles which create cracks. SCE mitigates these risks by installing waterproof barriers such as geomembranes, application of sealants, and the repair of concrete facings. This control mitigates the failure under normal operations risk driver. Dam surface protection reduces the likelihood of failure under normal operations but does not affect outcomes or consequences. SCE expects to complete one surface protection project in the 2029-2032 timeframe.

Spillway Remediation and Improvement (C3)

Spillways channel excess water from a dam reservoir safely away from the dam and its infrastructure. To ensure the continued safe operation of spillways, SCE undertakes repairs and upgrades. These may include the repair and replacement of damaged concrete and the installation or upgrade of protective features such as water-stops, drainage systems, and spillway gates. This control increases a dam's capability to safely channel excess water away from the dam and its infrastructure, reducing its susceptibility to flooding.

Low Level Outlet Improvements (C4)

Low level outlets allow for a controlled drawdown of reservoir levels during normal operations and can be used to lower the reservoir in an emergency to reduce the potential for dam failure. Improvement work may consist of repairing or replacing valves, gates, gate operators, or complete replacement of low-level outlets. This control primarily reduces safety and financial consequences of outcomes from inoperable facilities and the inundation of both unpopulated and populated areas.

Seepage Mitigation (C5)

Seepage mitigation reduces the likelihood that internal erosion will lead to the failure of embankment dams. These mitigations may include building new drains, rehabilitation existing drains, installing filters to prevent soil migration and filling in sinkholes. Reducing seepage may negatively impact downstream wetlands. For that reason, SCE may be required under the Clean Water Act to restore and preserve these wetlands. This control reduces the likelihood of failure under normal operations. It does not impact outcomes or consequences. SCE expects to complete one seepage mitigations project in the 2029-2032 period.

Instrumentation and Communication Improvements (C6)

Since many of SCE's dams are in remote areas, SCE uses instrumentation to monitor and operate dams from a centralized control center. SCE maintains and upgrades its monitoring, communications, and control systems to ensure reliability. Early detection of adverse conditions reduces risk across most or all risk drivers. However, a lack of data makes it difficult to quantify impacts. This control affects the safety consequences of inundation of unpopulated and populated areas by facilitating quick emergency response and notification to affected areas. SCE currently plans to complete 23 instrumentation and communication projects between 2029 and 2032.

Dam Removal (M1)

SCE includes Dam Removal in its proposed plan and both alternative plans.

While removing dams completely mitigates risk of dam failure, both the regulatory process and the implementation are lengthy and complicated. Dam removal addresses all risk drivers, consequences, and outcomes. SCE has begun to decommission one dam (Agnew Lake). SCE's proposed plan includes the decommissioning of two additional high-risk dams in the Rush Creek Hydroelectric project.

Relocation of Campgrounds (M2)

SCE discusses this mitigation but does not propose it as part of its proposed plan or either alternative plan due to a lack of "cost-effective opportunities to implement this mitigation in the 2029-2032 timeframe." [1150]

Since their construction, some previously inhabited areas downstream of SCE dams have become developed for recreation as campgrounds. While not inhabited permanently, these areas will host seasonable populations which would be exposed to risk of dam failure. Removing these campgrounds would reduce the populated area at risk of inundation. SCE did not identify any cost-effective opportunities to implement this mitigation in the 2029-2032 timeframe.

Purchase/Relocation of Inhabitable Structures (M3)

SCE discusses this mitigation but does not propose it as part of its proposed plan or either alternative plan due to the lack of "realistic opportunities to implement this mitigation in the 2029-2032 timeframe."[1151]

In the case of permanently inhabited areas, purchasing and removing structures will mitigate the potential for fatality and injury resulting from dam failures. This mitigation would impact risk drivers. Leading up to the current RAMP, SCE engaged in negotiations to purchase one inhabitable structure, but no agreement has been reached.

Dam Divestiture (M4)

SCE includes this mitigation in its second alternative plan.

Divestiture transfers dams and their risks to new owners. This mitigation affects neither risk drivers nor consequences and outcomes, rather new owners assume the risk. Divestiture would require the approval of FERC. Moreover, new owners would likely require compensation for assuming the risk of the transferred dams. While SCE has identified dams for divestiture, it does not include this mitigation in its proposed plan or first alternative plan because it believes that FERC would not allow transferring a dam's operating license without significant remediation. In its second alternative plan, SCE notes that, despite this barrier, if "a

[1150] SCE 2026 RAMP Ch.13, p. 37.

[1151] SCE 2026 RAMP Ch. 13, p. 38.

qualified party" expressed strong interest in acquiring a high-hazard dam, "SCE would re-evaluate the opportunity and could pursue divesture if cost-effective and aligned with customers' interests."[1152]

Observations and Findings

Dam Safety Program and External Inspections: In SCE's description of these foundational activities, SCE confusingly points to Table IV-3, a table that doesn't exist in its RAMP application, stating that "SCE allocates the costs [for these activities] across all Controls identified in Table IV-3..."[1153] SCE explained in a data request response that this was an error and the reference should have been to Table III-3 "List of Hydro Dam Controls." [1154, 1155]

Seismic Retrofit (C1): SPD notes that seismic retrofit may affect other drivers and outcomes by coincidentally addressing consequences. For example, rehabilitating concrete for seismic risk may also address issues like seepage and improve surface protection.

Instrumentation and Communication Improvements (C6): SPD notes that instrumentation mitigations are highly cost effective in comparison with other mitigations and controls.

SPD has no observations or findings on the other mitigations and controls described in SCE's Hydro Asset Failure chapter.

Alternatives Analysis

SCE presents two alternatives to its proposed plan. The proposed plan contains the following mitigations and controls:

[1152] SCE 2026 RAMP Ch. 13, p. 55.

[1153] SCE 2026 RAMP Ch. 13, p. 41 and p. 42.

[1154] SCE response to Data Request SPD-SCE-2026RAMP-009, Question 4.

[1155] SCE 2026 RAMP Ch. 13, p. 27.

Table 10-1. SCE Proposed Plan Projects, Costs, and Benefit-Cost Ratios (BCRs) (2029-2032)($000s)[1156]

Mitigation ID	Control/Mitigation Name	Operations & Maintenance (O&M) Costs	Capital Costs	Total Costs	BCR (Societal)	BCR (Weighted-Average Cost of Capital - WACC)	BCR (Hybrid)
CM1/CM2	Hydro Operations / Hydro Maintenance	$9,359		$9,359	0.0002	0.0002	0.0002
C1	Seismic Retrofit	$511	$8,000	$8,511	0.0104	0.0053	0.0059
C2	Dam Surface Protection	$336	$5,250	$5,586	0.0005	0.0002	0.0003
C3	Spillway Rehabilitation / Improvement	$4,005	$62,646	$66,651	0.1856	0.0918	0.1070
C4	Low Level Outlet Improvement	$638	$9,978	$10,616	0.0572	0.0303	0.0343
C5	Seepage Mitigation	$64	$1,000	$1,064	0.0020	0.0010	0.0011
C6	Instrumentation / Communication Enhancement	$205	$3,200	$3,405	0.3739	0.3077	0.3539
M1	Dam Removal	$1,761	$27,550	$29,311	0.0253	0.0048	0.0066
	All	**$16,878**	**$117,624**	**$134,502**	**0.1120**	**0.0568**	**0.0661**

SCE's first alternative plan includes all the controls and mitigations of the proposed plan. However, it anticipates a warmer and wetter climate due to climate change. This would mean less snowfall and more heavy precipitation events. This alternative adds three more dams to its Dam Surface Protection program (C2). It adds 40 percent in capital costs over the proposed plan while only providing an additional 30 percent risk mitigation. SCE deems the alternative to be less cost-effective than its proposed plan and rejects it.[1157] See Table 10-2 for information on SCE's first alternative plan.

[1156] SCE 2026 RAMP Ch. 13, Table VI-10 "Proposed Plan, Control Program Estimated Costs and Benefit Cost Ratios for 2029-2032," p. 47.

[1157] SCE 2026 RAMP Ch. 13, p. 52.

Table10-2. SCE's First Alternative Plan Projects, Costs, and BCRs ($000s)[1158]

Mitigation ID	Control/ Mitigation	Operations and Maintenance (O&M) Costs	Capital Costs	Total Costs	BCR (Societal)	BCR (WACC)	BCR (Hybrid)
C1	Seismic Retrofit	$366	$8,000	$8,366	0.0106	0.0054	0.0060
C3	Spillway Rehabilitation / Improvement	$4,473	$97,646	$102,120	0.1644	0.0820	0.0955
C4	Low Level Outlet Improvement	$457	$9,978	$10,435	0.0582	0.0308	0.0349
C5	Seepage Mitigation	$46	$1,000	$1,046	0.0021	0.0010	0.0011
C6	Instrumentation / Communication Enhancement	$147	$3,200	$3,347	0.3804	0.3130	0.3600
M1	Dam Removal	$1,262	$27,550	$28,812	0.0257	0.0049	0.0067
	All	**$7,519**	**$164,124**	**$171,643**	**0.1088**	**0.0553**	**0.0644**

SCE's second alternative plan also includes all the controls and mitigations of the proposed plan but removes one additional dam for a total of three dams removed. However, removing the additional dam would cost an additional $57 million in capital costs while only providing $326,000 in risk reduction benefit. SCE finds the second alternative plan nonviable.[1159] See Table 10-3 for information on SCE's second alternative plan.

[1158] SCE 2026 RAMP Ch. 13, Table VII-12 "Alt Plan #1, Control Program Estimated Costs and Benefit Cost Ratios for 2029-2032," p. 51.

[1159] SCE 2026 RAMP Ch. 13, p. 55.

Table 10-3. SCE's Second Alternative Plan Projects, Costs, and BCRs ($000s)[1160]

Mitigation ID	Control/ Mitigation	O&M Costs	Capital Costs	Total Costs	BCR (Societal)	BCR (WACC)	BCR (Hybrid)
C1	Seismic Retrofit	$345	$8,000	$8,345	0.0106	0.0054	0.0060
C2	Dam Surface Protection	$226	$5,250	$5,476	0.0005	0.0002	0.0003
C3	Spillway Rehabilitation / Improvement	$2,703	$62,646	$65,349	0.1893	0.0937	0.1091
C4	Low Level Outlet Improvement	$430	$9,978	$10,408	0.0584	0.0309	0.0350
C5	Seepage Mitigation	$43	$1,000	$1,043	0.0021	0.0010	0.0012
C6	Instrumentation / Communication Enhancement	$132	$3,064	$3,196	0.3878	0.3195	0.3675
M1	Dam Removal	$2,483	$57,550	$60,033	0.1122	0.0529	0.0619
M4	Dam Divestiture	$1,156	$26,800	$27,956.	0.4987	0.0941	0.1181
	All	**$7,519**	**$174,288**	**$181,807**	**0.1824**	**0.0691**	**0.0816**

Observations and Findings

Based on SCE's narrative description of its proposed plan and two alternatives, SCE's proposed plan offers the most cost-effective option to reduce risk. However, the numbers in SCE's RAMP application tables do not support these conclusions, apparently due to an error. Two Chapter 13 tables present conflicting proposed plan cost numbers due to SCE omitting the O&M costs associated with its compliance activities, Hydro Operations and Hydro Maintenance (CM1 and CM2) from one table's numbers.[1161] SCE corrected its error in a data request response.[1162] While SPD appreciates the efforts that SCE made in its responses to SPD's data requests, the errors and missing data in its application make it difficult to accept SCE's proposed plan with complete confidence.

[1160] SCE 2026 RAMP Ch. 13, Table VII-14 "Alt Plan #2 Control Program Estimated Costs and Benefit Cost Ratios for 2029-2032," p. 54.

[1161] The mismatched tables are Table VI-7 "Hydro Asset Failure Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032" (p. 44) and Table VI-10 "Proposed Plan, Control Program Estimated Costs and Benefit Cost Ratios for 2029-2032" (p. 47). SCE omitted O&M costs for compliance activities (estimated at $9,359,000) from the total cost for the proposed plan in Table VI-7.

[1162] SCE response to Data Request SPD-SCE-2026RAMP-007, Question 2.

BCR Calculations

SCE calculates BCR values for a total of 10 controls and mitigations for hydro asset failure risk. SCE follows RDF requirements for calculating its BCRs. See Tables 10-4 through 10-7 for information on the BCRs for SCE's proposed and alternative plans using different discount rates.

Table 10-4. Societal Discount Rate BCR Comparison Between Proposed and Alternative Plans (2029-2032)[1163]

Plan Name	Total Costs	Mitigation Benefits	BCRs
Proposed Plan	$118,367,898	$13,258,297	0.1120
Alternative 1	$158,858,759	$17,281,441	0.1088
Alternative 2	$206,055,217	$30,580,980	0.1484*

* This BCR value is 0.1824 in Chapter 13, Table VI-7 "Hydro Asset Failure Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032, p. 44. SCE corrected this number in its response to Data Request SPD-SCE-2026RAMP-009, Question 3.

Table 10-5. WACC Discount Rate BCR Comparison Between Proposed and Alternative Plans (2029-2032)[1164]

Plan Name	Total Costs	Mitigation Benefits	BCRs
Proposed Plan	$84,045,560	$4,773,087	0.0568
Alternative 1	$111,934,048	$6,194,015	0.0553
Alternative 2	$144,356,544	$8,150,284	0.0565*

[1163] The numbers in this table were calculated by SPD staff using SCE 2026 RAMP Ch. 13 work papers including the following spreadsheets (plan BCR tab): SCE 2026 RAMP_Hydro_T1A-1F; SCE 2026 RAMP_Hydro_T1A-1F_alt1; SCE 2026 RAMP_Hydro_T1A-1F_alt2; SCE 2026 RAMP_Hydro_T2A-2F; SCE 2026 RAMP_Hydro_T2A-2F_alt1; SCE 2026 RAMP_Hydro_T2A-2F_alt2; SCE 2026 RAMP_Hydro_T2G-3C; SCE 2026 RAMP_Hydro_T2G-3C_alt1; SCE 2026 RAMP_Hydro_T2G-3C_alt2; SCE 2026 RAMP_Hydro_T3D-3G; SCE 2026 RAMP_Hydro_T3D-3G_alt1; SCE 2026 RAMP_Hydro_T3D-3G_alt2; SCE 2026 RAMP_Hydro_T4A-4D; SCE 2026 RAMP_Hydro_T4A-4D_alt1; SCE 2026 RAMP_Hydro_T4A-4D_alt2.

[1164] The numbers in this table were calculated by SPD staff using SCE 2026 RAMP Chapter 13 work papers including the spreadsheets (plan BCR tab) cited for Table 10-4.

* This BCR value is 0.0691 in Chapter 13, Table VI-7 "Hydro Asset Failure Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032, p. 44. SCE corrected this number in its response to Data Request SPD-SCE-2026RAMP-009, Question 3.

Table 10-6. Hybrid Discount Rate BCR Comparison Between Proposed and Alternative Plans (2029-2032)[1165]

Plan Name	Total Costs	Mitigation Benefits	BCRs
Proposed Plan	$136,424,159	$9,017,637	0.0661
Alternative 1	$111,948,871	$7,209,507	0.0644
Alternative 2	$117,985,486	$9,627,616	0.0816

Observations and Findings

Missing Economic Impacts

SCE may have chosen an overly narrow set of attributes for assessing the benefits of risk mitigations. The benefits of risk mitigation consist of consequences avoided. SCE correctly considers fatalities, serious injury, and potential for serious injury. However, this ignores damage to the local economy. FEMA recommends estimating economic impacts such as loss of jobs, damage to property and infrastructure, and loss of services from business and other institutions.[1166]

BCRs Alone Do Not Show the Best Plan

Depending on the discount rate considered (societal, WACC, or hybrid), SCE's proposed plan may only represent the second-best option: the Alternative 2 BCR is better than the proposed plan under the societal and hybrid discount rates. In its response to an SPD data request, SCE cited regulatory and circumstantial factors for declining the alternative plans.[1167] Both alternative plans may face regulatory obstacles not captured in the BCRs. Meanwhile, divestiture of assets requires finding a willing buyer for SCE's high-risk assets. No such buyer has been identified. Given these obstacles, SCE's rejection of Alternative Plan 2 is appropriate. SCE's proposed plan of mitigations and controls appears to offer the most cost-effective risk mitigation plan that is both feasible and compliant with regulations across SCE's hydropower facilities.

[1165] The numbers in this table were calculated by SPD staff using SCE 2026 RAMP Chapter 13 work papers including the spreadsheets (plan BCR tab) cited for Table 10-4.

[1166] FEMA Dam Failure, p. 7-1.

[1167] SCE response to Data Request SPD-SCE-2026RAMP-007, Question 4.

Table 10-7. SCE's Proposed Risk Mitigation Plan (Hybrid Discount Rate)[1168]

Mitigation ID	Control/Mitigation Name	Scope	Present Value Total Costs	Present Value Mitigation Benefit	BCR
CM1/CM2	Hydro Operations / Hydro Maintenance	System wide	$6,279,551	$1,451	0.0002
C1	Seismic Retrofit	One project on Big Creek 3	$5,100,315	$30,054	0.0059
C2	Dam Surface Protection	One project on Big Creek 5	$3,601,125	$902	0.0003
C3	Spillway Rehabilitation / Improvement	Four projects in the Big Creek hydroelectric system	$41,279,772	$4,414,943	0.1070
C4	Low Level Outlet Improvement	Four projects in the Big Creek hydroelectric system	$7,446,145	$255,602	0.0343
C5	Seepage Mitigation	One project on Big Creek 7	$685,929	$775	0.0011
C6	Instrumentation	23 projects in the Big Creek and Bishop hydroelectric systems	$2,088,515	$739,095	0.3539
M1	Dam Removal	Removal of Rush Meadows Dam and partial removal of Agnew Lake Dam	$17,564,208	$115,230	0.0066
M2	Dam Divestiture	None planned			
All			**$84,045,560**	**$5,558,052**	**0.0661**

Problems with Tables

Although SPD considers that SCE's proposed plan is appropriate, it found numerous problems with SCE's RAMP Hydro Asset Failure chapter as submitted. The chapter referenced a table that didn't appear in the chapter and the numbers were not consistent across tables. In Table VI-7 "Hydro Asset Failure Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-

[1168] SCE 2026 RAMP Ch. 13 work paper "Data Tables – Hydro.xlsx" spreadsheet.

2032" (p. 44), SCE provides BCRs calculated under the three discount rates but only reports undiscounted costs. The table also neglects to provide mitigation benefits. Moreover, SPD's calculations to generate the Alternative 2 BCR calculations using values from SCE's work papers generated different BCRs than SCE reported in this table.

SCE later corrected its errors with an updated set of risk model tables in response to a data request from SPD,[1169] but the lack of substantiating data and the discrepancy in the BCRs for one of the alternative plans place SCE's conclusions in doubt.

Additional Problems with Tables

In addition to the errors mentioned above, SPD discovered problems with several tables in SCE's Hydro Asset Failure chapter. First, Table VI-8 "Proposed Plan's Pre-Mitigation LoRE and CoRE Risk Scores by Tranche" (p. 45), and Table VI-9 "Proposed Plan's Post-Mitigation LoRE and CoRE Risk Scores by Tranche" (p. 46) contain the same values. SCE clarified in a response to an SPD data request that it inserted the wrong table in the space of Table VI-9.[1170]

Second, the total costs for proposed mitigations and controls in Table VI-10 "Proposed Plan, Control Program Estimated Costs and Benefit Cost Ratios" (p. 47), do not match the respective total costs in the summary in Table VI-7 "Hydro Asset Failure Proposed Plan and Alternative Plans Summary of Control Program Forecast Costs and Benefit Cost Ratios for 2029-2032" (p. 44). The table where the total costs for the control and mitigation program match those recorded in the summary is Table VII-14 "Alt Plan #2 Control Program Estimated Costs and Benefit Cost Ratios for 2029-2032" (p. 54).

SPD observes that this lack of consistency within the application tables leads to a lack of confidence in the figures in SCE's RAMP application.

Issues with Work Papers

The inconsistencies in SCE's RAMP do not end with the RAMP application. SPD encountered further problems with the Chapter 13 work papers submitted by SCE. There were errors in several spreadsheets, including "Data Tables – Hydro," "Hydro Asset Failure Financials," and in the risk model spreadsheets. SPD was unable to reproduce the reported BCR values in the RAMP application from the "Data Tables – Hydro" spreadsheet. SCE provided a corrected version of this spreadsheet in response to a data request.[1171] However, even this corrected version only provided data for the proposed plan and did not include either alternative plan. Meanwhile, SCE mislabeled tabs for its plans in the "Hydro Asset Failure Financials" spreadsheet. SCE again provided a corrected version of this spreadsheet in response to a data request.[1172]

[1169] SCE response to Data Request SPD-SCE-2026RAMP-011, Question 7.

[1170] SCE response to Data Request SPD-SCE-2026RAMP-007, Question 3.

[1171] SCE response to Data Request SPD-SCE-2026RAMP-009, Question 3.

[1172] SCE response to Data Request SPD-SCE-2026RAMP-009, Question 6.

SPD found a more serious omission in SCE's Hydro Risk model: in the work paper providing discounted values for benefits and costs, SCE provides benefits discounted at all three discount rates (societal, WACC, and hybrid) but only provides costs discounted at two rates, societal and WACC (omitting hybrid). This makes it difficult to reproduce the numbers reported in SCE's RAMP application.

Errors in SCE's work papers made it difficult to evaluate the proposed risk mitigations and undermine the credibility of SCE's proposed risk mitigation plan.

Summary of Findings

SPD finds that:

1. While SCE presented a good summary of risks, its RAMP contained many errors and omissions which undermine its work. The slipshod quality of SCE's RAMP Hydro Asset Failure chapter undermines confidence in SCE's risk mitigations.
2. As SCE's small number of high-risk dams do not cluster into any easily discernable grouping, making each dam its own risk tranche is appropriate.
3. SCE created appropriate RRUs.
4. SCE has accounted for all relevant risk drivers for hydro asset failure risk.
5. Regarding climate impacts on dams, the case study of SCE's Vermillion Dam in SCE's Climate Pilot White Paper includes impacts from increased precipitation, as well as other climate impacts including wildfire and associated sedimentation, and the findings from this study seem applicable to its other dams. SCE determined that runoff from wildfires does not contribute directly to dam failure and presents minimal risk. However, SCE monitors research in this area, as many unknowns remain.
6. By omitting economic impacts from the benefits of risk mitigations for dam failure, SCE may have underestimated the consequences of the risk event and consequently the benefits from mitigations.
7. When describing cost allocation for its foundational activities, SCE referred to a non-existent table (Table IV-3). Although SCE corrected the reference in response to a data request, this omission made it difficult to evaluate the cost allocations for foundational activities.
8. The Alternative Plan 2 BCRs SCE presents in the RAMP application do not match the Alternative Plan 2 BCRs SPD calculated from the values in SCE's Chapter 13 work papers. While SCE did correct this in response to a data request, the discrepancies made it difficult to verify SCE's work.
9. SCE's description of its proposed plan contains serious errors which made it impossible to evaluate the plan as presented in SCE's application. SCE's Table VI-9 presenting post-mitigation risk scores erroneously contains the pre-mitigation risk scores from Table VI-8. SCE's Table VI-10 presenting detailed costs was likewise inaccurate, with the individual costs not adding up to the totals reported. SCE likewise corrected this error in a data request response. However, these errors weaken the credibility of SCE's risk mitigation plans for hydro asset risk.
10. The spreadsheets submitted by SCE in its work papers likewise contain several errors ranging from mislabeled tabs to missing data. Again, although SCE did correct these issues through data request responses, these errors made it difficult to reproduce SCE's work. This further undermines the credibility of SCE's risk mitigation plans for hydro asset risk.

Recommendations to Address Findings

1. SCE's Hydro Asset Failure chapter as initially filed contained many errors, inconsistencies, omissions, and duplications. After SPD received SCE's corrections, SCE's proposed plan for mitigating hydro asset failure risk appears to have no significant insufficiencies. While most of the problems with the initial version of the chapter were minor, they could have misled readers as to the effectiveness of SCE's proposed mitigation plan. In future proceedings, SCE should carefully proofread all documents prior to submission.
2. SCE's work papers had similar problems with completeness and consistency. Again, while SPD does not find significant insufficiencies with SCE's risk analysis, the poor quality of SCE's RAMP work papers raise doubts. These issues compelled SPD to clarify information through many data requests, which wastes time and slows down the evaluation process. SPD cannot be sure whether SCE corrected its work or simply altered its data to fit a desired result. SCE should take steps to ensure that all data submitted in the future are complete and consistent.
3. SCE should incorporate direct and indirect economic impacts when calculating the benefits of risk mitigations for dam failure. A fuller accounting of avoided consequences may result in BCRs for mitigations which can more effectively guide SCE in prioritizing future risk mitigation efforts.
4. SCE should examine the feasibility of using FEMA's HAZUS-MH tool for evaluating the consequences of dam failure.[1173] HAZUS-MH is an integrated system of software, data, and models used nationwide by emergency managers and researchers to estimate impacts from a variety of natural disasters including floods.[1174]
5. Although SPD is not evaluating SCE's Climate Pilot White Paper as part of its 2026 RAMP, SPD found the analysis presented there to be a good first step to evaluating the risks that a changing climate poses to SCE's hydropower facilities. SCE should carry out similar analyses on all its dams, carefully considering climate scenarios which lead to extreme precipitation, increased wildfires, and droughts.

[1173] FEMA Dam Failure, p. 7-1.

[1174] FEMA, Hazus (https://www.fema.gov/flood-maps/products-tools/hazus, accessed July 8, 2026).

11. Safety Culture, Organizational Structure, Executive and Utility Board Engagement, and Compensation Policies Related to Safety

Overview

A utility's safety culture is about the shared values, beliefs, and habits of all personnel at an organization, including executives, employees, and contractors, and how those values, beliefs, and habits show up in how people plan, act, and make decisions every day. A utility cannot truly be safe without integrating safety culture at all levels of employees—from entry-level to executive—and owning the company's path to improving its safety culture.

The following chapter presents Safety Policy Division's (SPD's) evaluation of Southern California Edison Company's (SCE's) Risk Assessment and Mitigation Phase (RAMP) Chapter 3, "Safety Culture, Organizational Structure, Executive and Utility Board Engagement, and Compensation Policies Related to Safety."

The RAMP evaluation process is not where the California Public Utilities Commission (CPUC or Commission) performs detailed evaluation of compliance with safety culture regulatory requirements, but, in accordance with CPUC Decisions 16-08-018[1175] and 18-12-014,[1176] SPD offers some observations on the information SCE provided regarding its safety culture program, executive and utility board engagement, and compensation policies as part of its 2026 RAMP application.

SCE's Safety Culture Program

SCE uses a five-tier safety culture maturity model, going from lowest to highest: counterproductivity, public compliance, private compliance, stewardship, and citizenship.[1177, 1178] In 2014, SCE began conducting triennial safety culture assessments to gauge its progress on the safety culture maturity scale.[1179] SCE stated in its 2022 RAMP application that it was "currently focused on evolving from Public Compliance … to

---

[1175] Interim Decision Adopting the Multi-Attribute Approach (or Utility Equivalent Features) and Directing Utilities to Take Steps Toward a More Uniform Risk Management Framework (D.16-08-018 of Aug. 2016), pp. 140-142 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M165/K862/165862364.PDF, accessed Oct. 12, 2026).

[1176] Phase Two Decision Adopting Safety Model Assessment Proceeding (S-MAP) Settlement Agreement With Modifications (D.18-12-014 of Dec. 2018), p. 35 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M250/K266/250266979.PDF, accessed Oct. 12, 2026).

[1177] SCE 2026 RAMP, Chapter 3 "Safety Culture, Organizational Structure, Executive and Utility Board Engagement, And Compensation Policies Related to Safety," Figure II-2 "Safety Culture Maturity Model," p. 6.

[1178] SCE response to Data Request SPD-SCE-2026RAMP-013, Questions 2 and 8.

[1179] SCE 2026 RAMP, Ch. 3, p. 6.

Private Compliance."[1180] In the present RAMP, SCE states that it has "advanced … to Private Compliance," and is "progressing toward Stewardship."[1181] In addition to these safety culture assessments, SCE documents and drives its safety culture progress using an annual "safety culture pulse" process involving "surveys and focus groups,"[1182] and an enterprise-wide Safety Work Plan, which is SCE's "primary annual planning and coordination mechanism for safety initiatives."[1183, 1184]

Safety culture is an element of a safety management system (SMS), a tool which an energy utility may use to foresee energy asset risks and plan for risk prevention and mitigation for employees, contractors, and the public. SCE describes its SMS as the mechanism by which it "organizes and enhances the way that SCE manages safety, helping ensure that programs and efforts are working together as required by the American National Standards Institute (ANSI) Z10.0-2019 standard."[1185, 1186] SCE notes that its "[s]afety risk management process is the driving force behind the SMS."[1187, 1188] This is a process SCE launched in 2024, with the combined effort of Edison Safety, an "organization [that] is responsible for the health and safety oversight and services at the corporate level,"[1189] and Enterprise Risk Management (ERM), a "Company-wide program that systematically identifies, evaluates, mitigates, and monitors risks."[1190] SPD describes these bodies further below. SCE plans to continue to improve its safety risk management process, noting that it

---

[1180] SCE 2022 RAMP, Chapter 9 "Employee Safety," p. 15 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M476/K640/476640383.PDF, accessed Sept. 14, 2026).

[1181] SCE 2026 RAMP, Ch. 3, p. 6.

[1182] SCE 2026 RAMP, Ch. 3, p. 10.

[1183] SCE 2026 RAMP, Ch. 3, p. 10.

[1184] SCE 2026 RAMP, Chapter 7 "Employee Safety," p. 27.

[1185] SCE 2026 RAMP, Ch. 3, p. 1, footnote 3.

[1186] The ANSI/ASSP Z10.0-2019 standard is an American National Standard providing a comprehensive framework for building and maintaining an Occupational Health and Safety Management System (OHSMS) that is sponsored and published by the American Society of Safety Professionals (ASSP) and approved by the American National Standards Institute (ANSI) (https://blog.ansi.org/ansi/ansi-assp-z10-2019-occupational-health-safety/, accessed Sept. 14, 2026).

[1187] SCE 2026 RAMP, Ch. 3, p. 13.

[1188] SCE refers to its "Safety risk management process," "Safety Risk Management Procedure," and "Safety Risk Management process," and "SMS risk management process" in the same section titled "ERM and Edison Safety Integration" (SCE 2026 RAMP, Ch. 3, pp. 13-14. SPD presumes these all refer to the same process or procedure.

[1189] SCE 2026 RAMP, Ch. 3, p. 1, footnote 1.

[1190] SCE 2026 RAMP, Ch. 3, p. 16.

plans on "expanding risk input scope and transitioning ownership of risk registers[1191] to operating units by 2027."[1192]

SCE notes that its triennial safety culture assessments led SCE to "create a formal safety governance structure, including executive- and senior-level safety councils,"[1193] referring to SCE's Executive Safety Council and Senior Safety Council. The Executive Safety Council "includes senior officers, and … serves as the SMS decision-making body."[1194] The Senior Safety Council acts as the implementation arm of the Executive Safety Council, "translat[ing] [its] direction into action by operationalizing safety policy, removing barriers to success, and ensuring consistent communication and alignment across [operational units]."[1195]

Observations and Findings

SPD observes that SCE describes its safety culture broadly but neglects to include anything specific from its safety culture assessment results to support its conclusion that it is "progressing toward Stewardship" on its safety culture maturity model.[1196] SPD additionally observes that SCE does not provide a ranked list of safety culture risks. Overall, SPD finds SCE's description of its safety culture program lacking in granularity and contextual information.

SCE's Governance, Accountability, and Organizational Structure

SCE reports that its parent company, Edison International (EIX), established the EIX Managing Committee that oversees SCE's enterprise risks and risk management program.[1197] This committee includes the "EIX President and [Chief Executive Officer], EIX General Counsel, EIX Chief Financial Officer, SCE [Chief Executive Officer], and certain other executive officers."[1198] It reviews and approves SCE's annual Enterprise Risk Management plans and updates to the EIX Board of Directors and Audit and Finance Committee.[1199]

[1191] SCE does not clarify the relationship between these risk registers and SCE's Enterprise Risk Register, from which SCE selects RAMP risks. SPD presumes they are related.

[1192] SCE 2026 RAMP, Ch. 3, p. 14.

[1193] SCE 2026 RAMP, Ch. 3, pp. 6-7.

[1194] SCE 2026 RAMP, Ch. 3, p. 14.

[1195] SCE 2026 RAMP, Ch. 3, p. 18.

[1196] SCE 2026 RAMP, Ch. 3, p. 6.

[1197] SCE 2026 RAMP, Ch. 3, p. 20.

[1198] SCE 2026 RAMP, Ch. 3, p. 20.

[1199] SCE 2026 RAMP, Ch. 3, p. 20.

SCE's Board of Directors (Board), consisting of independent individuals and the Chief Executive Officers of EIX and SCE, is responsible for overseeing SCE's employee, contractor, and public safety, among other things.[1200] The Board, through engagement with SCE management and its committees, "actively reviews [SCE's] ERM process and monitors significant risks."[1201] The Board Audit and Finance Committee oversees ERM's annual risk assessment report and "financial reporting risk."[1202] The ERM organization reports its findings "concerning key and emerging risks" to SCE's senior management and Board.[1203]

The Board Safety and Operations Committee plays an especially important role in the Board's engagement with SCE's safety culture and safety risk management process. This committee oversees "emergent operational risks and operational mitigation of risks," including "significant safety-related incidents involving employees, contractors, or members of the public."[1204,1205] This committee submits quarterly notifications to the California Office of Energy Infrastructure Safety (Energy Safety) as a requirement for renewal of the company's Safety Certification per California Public Utilities Code section 8389(e)(7), summarizing progress of the company's Wildfire Mitigation Plan, recommendations from the most recent Safety Culture Assessment performed by Energy Safety, and recommendations from the committee to improve safety at SCE.[1206] SCE leadership reports to this committee "at least four times a year" and the chair of the committee reports out to the full Board "on key operational updates."[1207]

As noted above, Edison Safety and SCE's ERM organization are responsible for SCE's safety risk management process. One of Edison Safety's primary responsibilities is to work with organizational units to ensure their safety programs comply with federal and state Occupational Safety and Health Administration (OSHA) requirements.[1208] The ERM organization has a broader mandate: it "systematically identifies, evaluates, mitigates, and monitors risks" at SCE.[1209] It established a standardized risk intake process approximately five years ago.[1210] ERM meets with senior leadership to review risks and mitigation plans on

[1200] SCE 2026 RAMP, Ch. 3, p. 20.

[1201] SCE 2026 RAMP, Ch. 3, p. 17.

[1202] SCE 2026 RAMP, Ch. 3, p. 17.

[1203] SCE 2026 RAMP, Ch. 3, p. 16.

[1204] SCE 2026 RAMP, Ch. 3, p. 17.

[1205] SCE 2026 RAMP, Ch. 3, p. 21.

[1206] SCE 2026 RAMP, Ch. 3, p. 21.

[1207] SCE 2026 RAMP, Ch. 3, p. 23.

[1208] SCE 2026 RAMP, Ch. 3, pp. 14-15.

[1209] SCE 2026 RAMP, Ch. 3, p. 16.

[1210] SCE response to Data Request SPD-SCE-2026RAMP-005, Question 6.

an ongoing basis.[1211] SCE reports that ERM took over the management of public safety concerns from Edison Safety in 2022.[1212] SCE moved the "Public Safety organization" under ERM "in recognition of the differences between managing employee and contractor safety on the one hand, versus public safety on the other."[1213]

As previously noted, SCE's Executive Safety Council includes senior officers. It acts as SCE's SMS decision-making body, while SCE's Senior Safety Council acts as the implementation arm of the Executive Safety Council. SCE reports that its Executive Safety Council is its "highest safety governance body," consisting of the SCE executive leadership team, Senior Vice Presidents and Vice Presidents reporting to the Chief Executive Officer and Chief Operating Officer, and senior representatives from EIX.[1214] The Executive Safety Council Safety Work Plan initiatives, which "function as key SMS risk management actions."[1215] As its implementation arm, the Senior Safety Council consists of operational unit directors and "a representative from one of the primary unions for SCE employees, the International Brotherhood of Electrical Workers (IBEW)," putting the organization in closer contact with front-line workers, enabling "practical solutions."[1216]

Observations and Findings

SPD observes that SCE's description of its governance, accountability, and organizational structure, like its safety culture program description, lacks granularity and contextual information. The relationship between the Public Safety organization and the ERM organization is unclear, and how both organizations influence organizational units is likewise unclear.

SCE's Compensation Policies Related to Safety

SCE describes its executive compensation structure as one that "promotes safety as a core value, helps ensure public safety, excellence in serving customers, and utility financial stability, and otherwise meets the requirements set forth in Public Utilities Code Sections 8389(e)(4) and 8389(e)(6)."[1217]

[1211] SCE 2026 RAMP, Ch. 3, p. 17.

[1212] SCE 2026 RAMP, Ch. 3, p. 16.

[1213] SCE 2026 RAMP, Ch. 3, p. 7.

[1214] SCE 2026 RAMP, Ch. 3, p. 18.

[1215] SCE 2026 RAMP, Ch. 3, p. 19.

[1216] SCE 2026 RAMP, Ch. 3, pp. 18-19.

[1217] SCE 2026 RAMP, Ch. 3, p. 23.

Energy Safety's Executive Compensation Review

SCE notes that its executive compensation structure is compliant with Public Utilities Code sections 8389(e)(4) and 8389(e)(6), which pertain to Energy Safety's review of its executive compensation structure as part of its review of a utility's compliance with requirements for a Safety Certification. Recent legislative changes from SB 254 (2025), signed into law and effective on September 19, 2025, amended the relevant sections of the Public Utilities Code. The sections covering executive compensation are now 8389(a)(4) and 8389(a)(6).[1218] Energy Safety reviewed and on December 29, 2025, issued an approval of SCE's executive compensation structure as submitted on May 23, 2025, noting that its decision was based on the Public Utilities Code section numbers that existed at the time of submission.[1219, 1220]

Per Energy Safety's approval letter, Public Utilities Code section 8389(e)(4) required that an electrical corporation's executive compensation structure promote safety as a priority and ensure public safety and utility financial stability, including implementing performance metrics for all executive officers that are measurable and enforceable. Public Utilities Code section 8389(e)(6) imposed further requirements on any new or amended contracts for executive officers, specifically placing strict limits on guaranteed cash compensation, with a primary portion of their compensation based on objective performance metrics. The approval letter concluded, "Energy Safety has determined that SCE's Executive Compensation Structure satisfies the requirements of the Public Utilities Code section 8389(e)(4) and 8389(e)(6) and the Guidelines," referring to Energy Safety's Executive Compensation Structure Guidelines Version 1.0.[1221, 1222]

Energy Safety reviewed the executive compensation packages for the six executive officers subject to the incentive compensation structure: "1) President and Chief Executive Officer; 2) Executive Vice President and Chief Operating Officer; 3) Senior Vice President (SVP) and Chief Financial Officer; 4) SVP and General Counsel; 5) SVP and Chief Customer Officer; and 6) SVP, Transmission and Distribution."[1223] Energy Safety notes that SCE's executive compensation consists of three parts: "Base Salary, Short-Term

---

[1218] Public Utilities Code, Chapter 6 "Wildfire Mitigation," section 8389 (https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=8389, accessed Sept. 22, 2026).

[1219] Energy Safety's 2025 Executive Compensation Docket Log indicating the Dec. 29, 2025, publication date of SCE's executive compensation approval letter (https://efiling.energysafety.ca.gov/Lists/DocketLog.aspx?docketnumber=2025-EC, accessed Sept. 22, 2026). The date of publication is visible in the header of the letter from page 2 on, but it is not indicated on the first page.

[1220] Energy Safety's Decision on SCE's 2025 Executive Compensation Structure (December 29, 2025), p. 1 (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=60007&docket=2025-EC&shareable=true, accessed Sept. 22, 2026).

[1221] Energy Safety's Decision on SCE's 2025 Executive Compensation Structure (December 29, 2025), p. 7.

[1222] Energy Safety's Executive Compensation Structure Guidelines for Electrical Corporations (April 2025) (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58205&shareable=true, accessed Sept. 22, 2026).

[1223] Energy Safety's Decision on SCE's 2025 Executive Compensation Structure (December 29, 2025), p. 3.

Incentive Program (STIP), and Long-Term Incentive Program (LTIP)."[1224] Public Utilities Code requires components for public safety and financial stability: Energy Safety notes that, while SCE incorporates both components, SCE leans toward the financial stability component, "as only 40 percent of SCE's STIP is weighted to safety measures and none of its LTIP contains safety measures."[1225]

SCE's Process for Determining Executive Compensation

SCE reports in its 2026 RAMP submission that its Board of Directors' Compensation and Executive Personnel Committee (Compensation Committee) determines "base salary, annual incentive compensation, and long-term incentive (LTI) awards," constituting the "Total Direct Compensation" for SCE's senior officers.[1226] SPD understands the "annual incentive compensation" to represent the "Short-Term Incentive Program" referenced by Energy Safety. SCE notes that this short-term compensation is based on goals and success measures set in June of the year prior to the goal year by the Board Safety and Operations Committee and approved by the Compensation Committee in February of the goal year.[1227] SCE's success measures for the short-term compensation are "[n]early all … based on meeting performance metrics that are objectively measurable."[1228] Regarding LTI awards, SCE notes that they are "largely tied to underlying EIX stock performance."[1229] This is the type of compensation that Energy Safety noted lacks any connection to safety measures.

The SCE notes that the Compensation Committee sometimes uses the short-term compensation program to signal shortcomings in performance, with the committee "reducing or eliminating annual incentive compensation for the year," even if the company meets specific safety and compliance goals.[1230] SCE notes that it is increasing the emphasis on safety in its short-term incentive program, "weighting the Safety and Resiliency goal category as 60% of the target award for 2026."[1231]

Observations and Findings

As Energy Safety noted, of the two types of incentives, short- and long-term, only the short-term serves as a leverage point for improving safety performance. SPD looked into the short-term compensation SCE provided to its senior officers in 2025, the same year as an ignition related to its electrical facilities caused

---

[1224] Energy Safety's Decision on SCE's 2025 Executive Compensation Structure (December 29, 2025), p. 3.

[1225] Energy Safety's Decision on SCE's 2025 Executive Compensation Structure (December 29, 2025), p. 3.

[1226] SCE 2026 RAMP, Ch. 3, p. 23.

[1227] SCE 2026 RAMP, Ch. 3, p. 24.

[1228] SCE 2026 RAMP, Ch. 3, p. 24.

[1229] SCE 2026 RAMP, Ch. 3, p. 23.

[1230] SCE 2026 RAMP, Ch. 3, p. 24.

[1231] SCE 2026 RAMP, Ch. 3, p. 24.

the Eaton Fire, as determined in April 2026 by the California Department of Forestry and Fire Protection (CAL FIRE) and Los Angeles County Fire Department.[1232] According to SCE's 2026 Proxy Statement from March 2026, in 2025 SCE only reduced the short-term compensation of EIX President Pedro Pizzaro by about 22 percent, and two other senior officers still received the majority of their short-term compensation awards (see Table 11-1).[1233] SPD observes that the performance metrics that determine whether a senior office receives short-term compensation may not address overall safety goals for the company, given the high level of awards given senior officers in a year when so much loss was caused by an ignition related to SCE facilities. SPD further observes that all the performance metrics for short-term compensation should be objectively measurable, not just "nearly all."

Table 11-1. 2025 Annual Incentive Award Payouts to EIX Executives[1234, 1235]

NEOs(1)	Salary(2) ($)	Annual Incentive Target as % of Salary(3) (%)	Individual Performance Factor (%)	Corporate Performance Factor (Before Adjustment)(4) (%)	Annual Incentive Payout (Before Adjustment)(4) ($)	Adjusted Corporate Performance Factor(5) (%)	Adjusted Annual Incentive Payout(5) ($)	Reduction in Payout(5) ($)
Pedro J. Pizarro	1,417,041	135	100	140	2,678,210	84	1,606,926	1,071,284
Maria Rigatti	842,603	89	115	140	1,211,410	—	—	—
Chonda J. Nwamu	544,973	85	98	140	635,541	—	—	—
Steven D. Powell	838,164	89	100	143	1,070,580	84	628,872	441,708
Jill C. Anderson	552,603	65	115	143	590,693	84	346,981	243,713

Summary of Findings

SPD finds that:

1. SCE's description of its safety culture program lacks granularity and contextual information.
2. SCE should ensure performance metrics that determine senior officers' short-term compensation may not be sufficiently tied to overall company safety performance and are not all objectively measurable.

[1232] South Pasadenan article "Eaton Fire Investigation Concludes: Electrical Arcing on Idle Edison Tower Caused the Catastrophic Blaze That Killed 19 & Wiped Out Altadena" (Aug. 4, 2026) (https://southpasadenan.com/eaton-fire-investigation-concludes-electrical-arcing-on-idle-edison-tower-caused-the-blaze-that-killed-19/, accessed Aug. 5, 2026).

[1233] SCE 2026 Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934 (SCE 2026 Proxy Statement), "2025 Annual Incentive Award Payouts," p. 48 (https://www.sec.gov/Archives/edgar/data/827052/000110465926027655/eix-20260423xdef14a.htm, accessed Sept. 22, 2026). Per this filing, Pedro Pizzaro's annual incentive target as a percentage of his salary was 135 percent and SCE paid him $1,606,926 for his annual incentive, which SPD calculates at 113.4 percent of his annual salary, listed here as $1,417,041. SPD calculates the reduction in his annual incentive from 135 to 113.4 percent at 21.6 percent.

[1234] SCE 2026 Proxy Statement, p. 48.

[1235] SCE's 2026 Proxy Statement covers the compensation paid to five "named executive officers" or NEOs, per the 2026 Proxy Statement, p. 80.

Recommendations to Address Findings

SPD recommends that:

1. SCE's description of its safety culture program should include more granularity and contextual information.
2. SCE should ensure performance metrics that determine senior officers' short-term compensation should be tied directly to overall company safety performance and should all be objectively measurable.

12. Environmental and Social Justice Pilot Study and White Paper

Overview

This chapter presents Safety Policy Division's (SPD's) summary and discussion of Southern California Edison Company's (SCE's) Environmental and Social Justice (ESJ) Pilot Study as documented in its Risk Assessment and Mitigation Phase (RAMP) chapter titled "Environmental and Social Justice (ESJ) White Paper," included as Appendix B to Chapter 2 "Risk Model and Benefit-Cost Ratio Methodology, and SCE's filing of July 14, 2026, Southern California Edison Company's (U 338-E) Environmental and Social Justice (ESJ) Pilot White Paper," which was due by July 15, 2026 per the Risk-Based Decision-Making Framework (RDF) Phase 2 Decision.[1236, 1237] This chapter takes into account the additional material provided in that July 14, 2026, filing. The latter filing contains some refinements, additions and corrections to the initial filing, including a "Lessons Learned" section after the first five action items. SCE submitted these filings pursuant to the requirements of the RDF Phase 2 Decision, described below.

Background

The RDF Phase 2 Decision (Dec. 2022) sets forth requirements for an ESJ pilot study to be undertaken by each large investor-owned utility (utility) as part of its next RAMP. The goal of the ESJ pilot study as set forth in the RDF Phase 2 Decision is to provide insight into how each utility's planned risk mitigations may affect disadvantaged and vulnerable communities (DVCs) from environmental and social justice perspectives. As part of the pilot study, each utility must address seven action items (described in more

[1236] SCE's full, final ESJ Pilot White Paper is available on the SCE web page CPUC Open Proceedings under 2026 RAMP listed with the file title "A2605018-SCE 2026 RAMP ESJ Pilot White Paper" (Open Proceedings web URL: https://www.sce.com/regulatory/regulatory-information/open-proceedings/cpuc-open-proceedings; 2026 RAMP web page URL: https://edisonintl.sharepoint.com/teams/Public/regpublic/Regulatory%20Documents/Forms/RIMS%20Doc%20Set%20View.aspx?id=%2Fteams%2FPublic%2Fregpublic%2FRegulatory%20Documents%2FPD%2FCPUC%2F22361, both accessed July 27, 2026).

[1237] "Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company shall each file a White Paper summarizing their Environmental and Social Justice (ESJ) Pilot Study by no later than two months after their respective next Risk Assessment Mitigation Phase (RAMP) filing deadline," per Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots with Appendices (D.22-12-027 of Dec. 21, 2022), Ordering Paragraph (OP) 6, p. 67 (https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668, accessed May 27, 2026).

detail below)[1238] using the RDF Phase 2 Decision's definition for DVCs.[1239] These action items include evaluating the impacts of the utility's risk mitigations on DVCs, identifying opportunities to better target investments to improve community resilience and environmental outcomes, including air quality and climate resilience in DVCs, and exploring ways to enhance equitable access to utility programs.

The RDF Phase 2 Decision further requires that each utility file a white paper two months after its RAMP filing deadline summarizing the findings of its ESJ pilot study.[1240] This white paper is required to: [1241]

1. Identify areas for further exploration and challenges each utility faced incorporating ESJ into the RDF.
2. Discuss how to better target mitigations that improve local air quality.
3. Explore how to better target mitigations that improve climate resilience in DVCs.

ESJ Pilot Study Plan Consultation

Pursuant to the RDF Phase 2 Decision requirements, SCE presented its pilot study plan ("ESJ Pilot Plan") in a series of outreach presentations held between August 2025 and March 2026.[1242] This met requirements for sharing information about its plan with the California Public Utilities Commission's (CPUC's) Energy Division Staff, the Community-Based Organization Working Group (CBOWG), the Disadvantaged Communities Advisory Group (DACAG), and the public.[1243,1244] In its ESJ Climate White Paper submitted with its RAMP, SCE provides a summary of feedback and potential ways SCE could address the feedback.

[1238] D.22-12-027, OP 5, pp. 65-67.

[1239] D.22-12-027, pp. 48-49, adopting the definition of DVCs found in D.20-08-046 (from Rulemaking 18-04-019), p. 13 and OP 1, p. 119 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K285/346285534.PDF, accessed July 27, 2026). The definition in D.20-08-046 states that DVCs "consist of communities in the 25% highest scoring census tracts according to the most recent version of the California Communities Environmental Health Screening Tool (CalEnviroScreen), as well as all California tribal lands, census tracts with median household incomes less than 60% of state median income, and census tracts that score in the highest 5% of Pollution Burden within CalEnviroScreen, but do not receive an overall CalEnviroScreen score due to unreliable public health and socioeconomic data" (OP 1, p. 119).

[1240] D.22-12-027, OP 6, p. 67.

[1241] D.22-12-027, OP 6, p. 67.

[1242] Outreach activities included "meeting with the Disadvantaged Communities Advisory Group (DACAG) on August 15, 2025, Community-Based Organization Working Group (CBOWG) on August 12, 2025, ESJ Pilot Public Webinar on August 27, 2025, as well as SCE's Climate Resilience Leadership Group (CRLG) on March 5, 2026," per SCE 2026 RAMP, Chapter 2 "Risk Model and BCR Methodology," Appendix B "Environmental and Social Justice (ESJ) White Paper," p. 31.

[1243] SCE 2026 RAMP, Ch. 2, Appendix B, Environmental and Social Justice (ESJ) White Paper, p. 31.

[1244] D.22-12-027, OP 5, p. 66.

Action Item Implementation

Pursuant to the RDF Phase 2 Decision requirements, SCE identified DVCs within its service territory using CPUC criteria, taking into account the community's CalEnviroScreen rankings, the intersection of the community with low-income census tracts and areas with high pollution burdens, and whether a community is on tribal land.[1245] Based on this assessment, SCE estimated that approximately 1.6 million SCE service accounts, representing about 4.8 million customers (roughly one-third of its customer base) are located within DVCs. [1246] Geographically, SCE found DVCs encompass approximately 30,955 square miles, or about 60 percent of SCE's service territory.[1247]

SCE next identified the risks that it believed would provide meaningful insights for its ESJ pilot study. SCE evaluated each RAMP risk in its Enterprise Risk Register for relevance to one or more of the seven RDF Phase 2 Decision action items (see above). The three RAMP risks that SCE evaluated as most aligned with the seven action items include SCE's top overall enterprise risks: wildfires associated with utility operations, Public Safety Power Shutoff (PSPS), and overhead equipment failure.[1248, 1249]

Below SPD discusses SCE's approach to each of the RDF Phase 2 Decision action items.

Action Item 1: Consider Equity

Action Item 1 directs the utility to consider equity in the evaluation of consequences and risk mitigation within the RDF, using the most current version of CalEnviroScreen to better understand how risks may disproportionately impact some communities more than others.[1250]

SCE identifies the drivers, consequences, and mitigations for wildfires associated with utility operations, PSPS, and overhead equipment failure, and compared risk consequences and mitigation impacts across DVCs and non-DVCs through quantitative and geospatial analyses.[1251]

Observations and Findings

SCE addresses this action item by assessing how its three selected RAMP risks and their corresponding mitigations are distributed across DVCs and non-DVC areas. Using a data-driven approach by integrating

---

[1245] See Footnote 1239 for more on the definition of DVCs.

[1246] SCE 2026 RAMP, Ch. 2, Appendix B, p. 5.

[1247] SCE 2026 RAMP, Ch. 2, Appendix B, p. 5.

[1248] SCE 2026 RAMP, Ch. 2, Appendix B, pp. 7-8.

[1249] See "SCE's RAMP Risk Selection Process" above for more information on this topic.

[1250] D.22-12-027, OP 5(a), p. 66.

[1251] SCE 2026 RAMP, Ch. 2, Appendix B, pp. 9-16.

spatial risk modeling with mitigation deployment data, SCE provides a consistent framework to evaluate differential exposure to the three risks. SCE's analysis is supported by service account distribution and asset mapping pre- and post-mitigation risk comparisons as well as across SCE's High Fire Risk Area (HFRA) (encompassing the CPUC-defined High Fire Threat District [HFTD] in SCE's territory) and regions outside the HFRA.

DVCs primarily lie outside SCE's HFRA, with only 7 percent of service accounts in SCE's HFRA belonging to DVCs.[1252] Therefore it follows that SCE found that pre-mitigated risk for wildfire and PSPS, which chiefly occur within SCE's HFRA, largely does not occur in DVCs, with only 9 percent and 14 percent of these risks, respectively, projected to occur in DVCs (estimated as of the start of 2029).[1253] However, SCE projects that, as of the start of 2029, 43 percent of pre-mitigated risk for overhead equipment failure will fall in DVCs.[1254] About half of SCE's overhead infrastructure outside SCE's HFRA serves DVCs, including 51 percent of distribution miles and 49 percent of transmission miles, so it follows that DVCs are relatively more exposed to overhead equipment failure risk.[1255]

SCE shows projected risk in DVCs after risk mitigation going up slightly for wildfire (from 9 to 10 percent), staying the same for PSPS (14 percent), and going down slightly for overhead equipment failure (from 43 to 41 percent).[1256] These findings suggest that mitigation investments targeting infrastructure outside the HFRA, particularly those addressing overhead equipment failure risk, may provide the greatest direct benefits to DVC populations.

Action Item 2: Consider Investments in Clean Energy Resources

Action Item 2 directs the utility to consider investments in clean energy resources in the RDF as a possible means to improve safety and reliability and mitigate risks in DVCs.[1257]

SCE addresses this action item by describing its PSPS risk mitigation resources throughout its service territory, including in DVCs.

[1252] SCE 2026 RAMP, Ch. 2, Appendix B, Table 3-1 "Distribution of SCE Service Accounts by HFRA/HFTD vs. non-HFTD and Disadvantaged Vulnerable Community Status," p. 10.

[1253] SCE 2026 RAMP, Ch. 2, Appendix B, Table 3-3 "Total and DVC-related Monetized Pre-Mitigated (Start of 2029) Risk for Each of the Selected RAMP Risks," p. 12.

[1254] SCE 2026 RAMP, Ch. 2, Appendix B, Table 3-3, p. 12.

[1255] SCE 2026 RAMP, Ch. 2, Appendix B, Table 3-2 "Distribution of SCE Overhead Distribution and Transmission Assets by HFRA/HFTD vs. non-HFTD and Disadvantaged Vulnerable Community Status," p. 10.

[1256] SCE 2026 RAMP, Ch. 2, Appendix B, Tables 3-3 and 3-4, p. 12.

[1257] D.22-12-027, OP 5(b), p. 66.

Observations and Findings

SCE addresses this action item by describing its approach to mitigating PSPS risk. This approach includes employing battery storage resources and other localized generation solutions like backup power systems, including for customers located in DVCs. The CPUC cites the following as examples of clean energy resources: "solar, rooftop solar, geothermal, batteries, [and] energy efficiency."[1258]

SPD finds that SCE's efforts to shore up localized power and support critical facilities during PSPS events should improve community resilience, including in DVCs. These resources can help reduce customer impacts, improve outage resilience, and support community preparedness. Their deployment in coordination with local governments and customers may provide additional benefits to DVCs while supporting wildfire risk mitigation and broader environmental justice objectives.

Although SCE provides a list of resources it uses to mitigate PSPS risk, SCE does not provide information on the quantity or deployment of these resources within DVCs.[1259] This essentially limits SPD's ability to assess the benefits of these resources to DVCs.

Action Item 3: Consider Mitigations That Improve Air Quality and Public Health

Action Item 3 directs the utility to consider mitigations that improve local air quality and public health in the RDF, including supporting data collection efforts associated with Assembly Bill 617 of 2017 regarding community air protection programs.[1260]

SCE identifies wildfire and PSPS risk mitigation activities and assesses how the mitigation activities might benefit DVCs in its service territory.

Observations and Findings

SCE addresses this action item by evaluating whether its proposed mitigations for wildfire, PSPS, and overhead equipment failure risks could provide ancillary air quality and public health benefits, particularly for communities identified under Assembly Bill (AB) 617 "Community Air Protection Program" (2017).[1261] SCE's assessment focuses on the potential co-benefits of risk mitigation measures, such as wildfire

---

[1258] CPUC Press Release, CPUC Orders Historic Clean Energy Procurement To Ensure Electric Grid Reliability and Meet Climate Goals (June 24, 2021) (https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-orders-clean-energy-procurement-to-ensure-electric-grid-reliability, accessed July 29, 2026).

[1259] SCE 2026 RAMP, Ch. 2, Appendix B, Table 3-5 "Clean Energy Resources used to reduce the Impacts of PSPS Events," (p. 18).

[1260] D.22-12-027, OP 5(c), p. 66.

[1261] California Air Resources Board web page About CAP Program (https://ww2.arb.ca.gov/capp/ab/about-cap-program/about, accessed July 29, 2026).

prevention, clean energy resources deployed during PSPS events, and reliability improvements that reduce outage duration. However, SCE notes that improving air quality and public health are not the primary objectives of these mitigations; therefore, these benefits are not quantified in the RAMP analysis.

SCE states that its wildfire risk mitigation efforts contribute to air quality and public health by avoiding wildfire smoke and particulate matter exposure through reduced ignition risk. SCE also states that battery storage and other localized generation solutions provided through its PSPS risk mitigation efforts can reduce customer reliance on portable fossil-fuel generators and thereby exposure to their localized air pollution, improving air quality and public health.

Although the more direct benefits to air quality and public health come from SCE's wildfire and PSPS risk mitigation efforts, SCE indicates that its overhead equipment failure risk mitigation efforts may reduce the frequency and duration of outage events, thereby reducing customer reliance on portable fossil-fuel generators and other backup energy sources that might degrade air quality.

SCE acknowledges significant limitations in quantifying these air quality and public health benefits, particularly in attributing air quality and public health outcomes to specific utility mitigations or communities. For example, SCE notes wildfire smoke comes from ignitions both associated and not associated with utility operations and the smoke extends beyond geographic and jurisdictional boundaries, making it challenging to establish how SCE's wildfire mitigation efforts might influence a particular community's exposure to wildfire smoke.

Action Item 4: Evaluate How Proposed Mitigations Impact Climate Resiliency in DVCs

Action Item 4 directs the utility to evaluate how the selection of proposed mitigations in the RDF may impact climate resiliency in DVCs.[1262]

SCE identifies how its efforts mitigating wildfire, PSPS, and overhead equipment failure risk may support climate resiliency and discusses the distribution of the benefits of its efforts across DVCs and non-DVCs.

Observations and Findings

SCE addresses this action item by evaluating how its proposed mitigations might impact climate resiliency in DVCs.

SCE notes its finding discussed above in Action Item 1 that DVCs in SCE's service territory do not tend to fall in high-risk areas for wildfire or PSPS, so SCE finds it difficult to connect benefits from wildfire and PSPS risk mitigation efforts with DVC climate resiliency. Regarding overhead equipment failure risk mitigation efforts that reduce impacts from outages, SCE finds it difficult to connect these efforts with

[1262] D.22-12-027, OP 5(d), p. 67.

DVC climate resiliency in part because SCE has not found "a clear or direct linkage between specific climate hazards and outage events on SCE's system."[1263] SCE has identified the need for additional study of this linkage and points to its Climate Adaptation Vulnerability Assessment (CAVA) filing and accompanying Community Engagement Plan[1264] and its Climate Pilot White Paper[1265] as sources for more discussion of the connection between its risk mitigation efforts and climate resiliency in DVCs.

Action Item 5: Evaluate Whether Wildfire Smoke Disproportionately Impacts DVCs

Action Item 5 directs the utility to evaluate if estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs.[1266]

SCE discusses different approaches to assessing disproportionate impact of wildfire smoke on DVCs, including the findings of Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) in their ESJ Pilot Study Plans submitted in 2024 and 2025, respectively. It also summarizes the findings on this topic produced by consultants, academics, and public agencies.[1267]

Observations and Findings

SCE addresses this action item by discussing ways to assess whether wildfire smoke may disproportionately impact DVCs.

SCE finds that wildfire smoke is widely recognized as a public health concern, particularly due to exposure to fine particulate matter (PM2.5) and that DVCs may be more vulnerable to the effects of wildfire smoke because of existing socioeconomic, health, and environmental factors, including limited access to healthcare, higher rates of outdoor work, and greater baseline pollution burdens.

However, SCE also finds that current data and methodologies are not sufficiently mature to reliably quantify whether wildfire smoke impacts are disproportionately experienced by DVCs or to isolate those effects from other contributing factors. SCE's discussion of the various approaches to this topic highlights significant uncertainties related to smoke dispersion, exposure modeling, health outcome attribution, and

---

[1263] SCE 2026 RAMP, Ch. 2, Appendix B, p. 24.

[1264] SCE's latest CAVA and Community Engagement Plan are accessible on SCE's web page Climate Adaptation (https://www.sce.com/about-sce/environment/climate-adaptation, accessed July 29, 2026).

[1265] SCE 2026 RAMP, Ch. 2, Appendix A.

[1266] D.22-12-027, OP 5(e), p. 67.

[1267] SCE references the findings of consultant Jensen Hughes, as presented on behalf of the Office of Energy Infrastructure Safety in a meeting held in 2025, and additional sources including publicly available studies relevant to the California case from 2023 through 2025 such as materials from the California Department of Public Health and California Air Resources Board.

the challenge of linking specific wildfire events to localized community impacts. As a result, while DVCs may face heightened vulnerability to wildfire smoke, it appears additional research is needed before wildfire smoke impacts can be credibly incorporated into utility risk models or used to support quantitative comparisons across communities, including DVCs.[1268]

Action Item 6: Estimate How Mitigations Impact and Benefit DVCs

Action Item 6 directs the utility to estimate the extent to which risk mitigation investments included in the RDF impact and benefit DVCs independently and in relation to non-DVCs in the IOU service territory.[1269]

SCE points to the analysis it presented under Action Item 1, which shows the pre- and post-mitigation risk values for the selected RAMP risks in DVCs.[1270]

Observations and Findings

SCE addresses this action item by projecting the value of SCE's risk mitigation efforts to DVCs. See the discussion of differential risk impacts on DVCs and mitigation benefits for DVCs under Action Item 1 above.

Action Item 7: Enhance Opportunities for DVC Participation in Risk Mitigation and Climate Adaptation

Action Item 7 directs the utility to enhance outreach and public participation opportunities for DVCs to meaningfully participate in risk mitigation and climate adaptation activities consistent with Decision 20-08-046.[1271]

SCE reports on its stakeholder outreach activities including engagement with DACAG, CBOWG, and the public through presentations about its ESJ pilot study in the period between August 2025 and March 2026.

Observations and Findings

SCE addresses this action item by providing opportunities for DVC participation in SCE's risk mitigation and climate adaptation.

SPD observes that SCE's outreach efforts demonstrate a proactive attempt to engage DVC stakeholders through multiple forums, including advisory groups, community-based organizations, public webinars, and

---

[1268] SCE 2026 RAMP, Ch. 2, Appendix B, p. 27.

[1269] D.22-12-027, OP 5(f), p. 67.

[1270] SCE 2026 RAMP, Ch. 2, Appendix B, Tables 3-3 and 3-4, p. 12.

[1271] D.22-12-027, OP 5(g), p. 67.

climate resilience discussions. The feedback collected highlights several recurring barriers to meaningful participation, including accessibility challenges, trust and transparency concerns, and language and cultural barriers. SCE reports that stakeholders also emphasized that complex technical information and coordination across utility programs and regulatory initiative factors can limit effective engagement.

The findings suggest that effective ESJ engagement goes beyond regulatory compliance and requires ongoing, community-centered outreach tailored to local needs. Stakeholders emphasized the importance of plain-language communication, trusted community partnerships, multilingual outreach, and sustained engagement to build credibility and increase participation. Overall, the pilot appears to offer SCE valuable insights into opportunities to enhance future outreach efforts and underscores the need to better align utility engagement strategies with the priorities and circumstances of DVCs.

Recommendations

SCE generally complied with the directives outlined in the RDF Phase 2 Decision by developing plans to incorporate ESJ considerations into the RDF.

While SCE addressed the required action items, SPD recommends the following to strengthen its approach to implementation of the RDF Phase 2 Decision action items.

Action Item 2: SCE recognizes providing battery storage resources and other localized energy generation solutions as a resilience strategy to reduce customer impacts during PSPS events and support DVCs impacted by outages, but it does not provide sufficient information on the deployment of these resources within DVCs. SPD recommends that SCE report the quantity, location, and deployment of battery storage resources and other localized energy generation solutions in DVCs to assess their distributional benefits and effectiveness in advancing ESJ objectives.

Action Item 3: SCE identified potential air quality and public health co-benefits from wildfire, PSPS, and overhead equipment failure risk mitigations, but it does not quantify these benefits due to methodological challenges in attributing outcomes to specific utility actions or communities. SPD recommends that SCE further develop methods to evaluate and, where feasible, quantify the air quality and public health co-benefits of its mitigations, particularly for communities disproportionately affected by environmental burdens.

Action Item 4: SPD recommends that SCE enhance future RAMP analyses by developing methods to better quantify and assess the climate resiliency benefits of risk mitigations for DVCs and other disproportionately impacted communities.

Action Item 5: SPD recommends that SCE continue monitoring research and advancing methodologies to better assess wildfire smoke impacts on DVCs and evaluate whether these impacts can be credibly incorporated into future ESJ and RAMP analyses.

Action Item 6: SPD recommends that SCE supplement its analysis with metrics that assess whether mitigation benefits are proportional to DVC risk exposure, enabling a more meaningful evaluation of equity outcomes.

Action Item 7: SCE's summary of stakeholder feedback from SCE's outreach around its ESJ pilot study indicates that stakeholders want sustained, community-centered approaches tailored to local needs. SPD recommends that SCE strengthen future ESJ engagement efforts by expanding multilingual outreach, using plain-language communications, partnering with trusted community organizations, and fostering ongoing engagement with DVCs.

SPD recommends the following to strengthen SCE's approach to integrating ESJ concerns in the RDF beyond the ESJ pilot study.

- Although limitations on quantifying impacts of utility risk mitigations on air quality make it difficult to attribute benefits to air quality at the community level, SCE should continue to prioritize mitigations that reduce wildfire risk, enhance resilience in vulnerable communities, and integrate data about future climate, air pollution, and DVCs to better inform investment decisions.
- SCE should expand multilingual, plain-language outreach, partner with trusted community organizations, and coordinate engagement across CPUC proceedings to reduce stakeholder fatigue.
- SCE should continue to develop methods to evaluate impacts and benefits of mitigations on DVCs, including developing robust metrics to quantify ESJ benefits, especially for non-spatial mitigation programs, distinguishing between climate adaptation and risk mitigation objectives.

Safety Policy Division Evaluation Team

The following SPD staff members contributed to this report:

Adam Barsch, Research Data Specialist

Jeremy Battis, M.C.P, Sr. Regulatory Analyst

Danjel Bout, Ph.D., SPD Director

Anthony Castelletto, Sr. Regulatory Analyst

Ed Charkowicz, Retired Annuitant

Emily Chen, Regulatory Analyst

Hafizur Chowdhury, P.E., Sr. Utilities Engineer

John Deng, Sr. Regulatory Analyst

Amin Emrani, PhD, P.E., SMIEEE, Sr. Utilities Engineer

Gary Ermann, Utilities Engineer

Fred Hanes, P.E., Project and Program Supervisor

Tyler Holzschuh, Sr. Utilities Engineer

Anne Kim, Sr. Regulatory Analyst

Richard Kyo, Sr. Utilities Engineer

Konstantin Lavor, Research Data Specialist

Sara Moore, M.P.P./M.A., Sr. Risk Analyst, RAMP Evaluation Project Lead

Arthur O'Donnell, M.C., Retired Annuitant

Chirag "CJ" Patel, P.E., P.M.P., Sr. Utilities Engineer,

Kim Phan, M.S., IT Specialist

Junaid Rahman, Sr. Regulatory Analyst

Anwar "Syed" Safvi, Sr. Utilities Engineer

Harjit Singh, Sr. Regulatory Analyst

Arnold Son, SPD Program Manager

Henry Sweat, Sr. Utilities Engineer

Acknowledgements

The SPD evaluation team would like to acknowledge the contributions during public workshops and other input provided by parties in this proceeding.

A Note on Informal Comments

The Rate Case Plan in Decision 20-01-002 does not include informal comments.[1272] As such, parties to the proceeding were not required to submit informal comments prior to filing their comments on SCE's RAMP application and SPD's evaluation report.

However, in this proceeding's Scoping Memo, informal comments were welcomed from parties with a due date of September 4, 2026. Informal comments SPD received by that date are appended to the end of this report.

SPD received informal comments from five parties. In particular, SPD's analysis relied in part on the discovery and informal comments by The Utility Reform Network (TURN) and Mussey Grade Road Alliance (MGRA). However, due to the extensive nature of some of the comments and schedule constraints, the insights shared by parties may not be fully integrated into the present evaluation report.

[1272] Decision Modifying the Commission's Rate Case Plan for Energy Utilities (D.20-01-002 of Jan. 2020), Appendix A, p. A-1 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF, accessed Oct 9, 2026.

Informal Comments

SPD appends below the informal comments it received from parties to CPUC proceeding A. 26-05-018:

- Attachment 1: California Public Advocates Office (Cal Advocates)
- Attachment 2: Energy Producers and Users Coalition (EPUC)
- Attachment 3: Mussey Grade Road Alliance (MGRA)
- Attachment 4: Small Business Utility Advocates (SBUA)
- Attachment 5: The Utility Reform Network (TURN)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) Regarding 2026 Risk Assessment Mitigation Phase.	Application 26-05-018

THE PUBLIC ADVOCATES OFFICE INFORMAL COMMENTS ON THE APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U338-E) REGARDING 2026 RISK ASSESSMENT MITIGATION PHASE

ANNA YANG
Senior Regulatory Analyst

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

PETER CHAU
Attorney

Public Advocates Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-1682
Email: Peter.Chau@cpuc.ca.gov

September 4, 2026

TABLE OF CONTENTS

I. INTRODUCTION 1

II. COMMENTS 1

A. SCE distorts and inflates its mitigation cost-benefit analyses. 1

1. SCE's cost comparisons between mitigation alternatives do not reflect the full cost burden to ratepayers. 2

2. SPD should require SCE to supplement its RAMP filing with complete capital cost estimates so that the Commission can assess which mitigations provide the best cost-benefits for ratepayers. 4

B. SCE fails to evaluate the risk of idle or out-of-service transmission assets in its RAMP wildfire risk assessment. 5

1. SPD should require SCE to supplement its RAMP with a complete analysis of this risk. 7

III. CONCLUSION 9

APPENDIX A

APPENDIX B

APPENDIX C

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) Regarding 2026 Risk Assessment Mitigation Phase.	Application 26-05-018

THE PUBLIC ADVOCATES OFFICE INFORMAL COMMENTS ON THE APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U338-E) REGARDING 2026 RISK ASSESSMENT MITIGATION PHASE

I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) hereby submits these Informal Comments on the Southern California Edison Company (SCE) Application (A.) 26-05-018 regarding its 2026 Risk Assessment and Mitigation Phase (RAMP) Report.[1] The Commission's Safety Policy Division (SPD) should require SCE to supplement its 2026 RAMP report by including complete capital costs and idle transmission-line risks in its assessment.

II. COMMENTS

A. SCE distorts and inflates its mitigation cost-benefit analyses.

In its 2026 RAMP Report, SCE proposes to deploy approximately 189 miles of Targeted Undergrounding (TUG) and 455 miles of Covered Conductor (CC). In certain locations CC would be paired with fifty-five Rapid Earth Fault Current Limiter (REFCL) devices.[2] The RAMP also presents alternative mitigation plans and compares the cost-

[1] A.26-05-018, *Application of Southern California Edison Company (U 338-E) Regarding 2026 Risk Assessment Mitigation Phase* (SCE RAMP Report), May 15, 2026.

[2] SCE RAMP Report, Chapter 4: Wildfire and PSPS, at 16.

effectiveness of these alternatives using benefit-cost ratio (BCR) analysis.[3, 4]

1. SCE's cost comparisons between mitigation alternatives do not reflect the full cost burden to ratepayers.

SCE's BCR methodology uses the following formulas for CC and TUG[5] to compare against risk mitigation alternatives:[6]

$$\text{CC BCR} = \frac{\text{Modeled Benefit from CC}}{\text{[Capital Cost for CC + (O\&M cost-O\&M Savings)]}}$$

$$\text{TUG BCR} = \frac{\text{Modeled Benefit from TUG}}{\text{[Capital Cost for TUG + (O\&M cost-O\&M Savings)]}}$$

However, SCE accounts only for the capital costs (to plan, engineer, design and construct the identified scope), annual operating and maintenance (O&M) costs, and O&M savings.[7] SCE excludes significant additional capital-related costs that it seeks to recover from ratepayers, including but not limited to rate of return, income and property

---

[3] Alternative #1 reduces TUG to approximately 120 miles and increases deployment of CC to approximately 751 miles, enabling full elimination of remaining bare conductor across HFRA. This plan would cost approximately the same as the Proposed Plan but would achieve less risk reduction. SCE RAMP Report, Chapter 4: Wildfire and PSPS, at 81, 83.

[4] Alternative #2 proposes to deploy an additional 37 miles of TUG compared to SCE's Proposed Plan. This plan gives the largest modeled reduction in wildfire risk but presents challenges in terms of cost and feasibility of execution. SCE RAMP Report, Chapter 4: Wildfire and PSPS, at 81, 87.

[5] SCE RAMP Report, Chapter 4 Workpaper: *BCR Methodology for Covered Conductor and Targeted Undergrounding*, at WP-1.

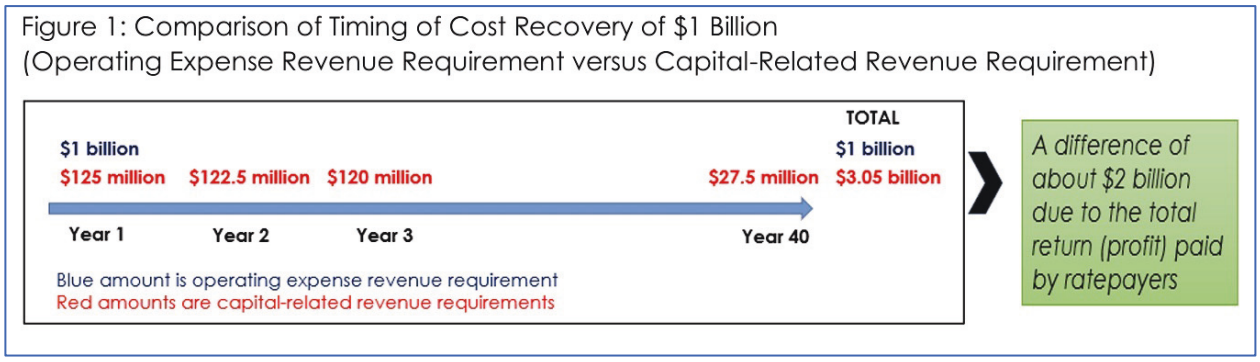
[6] In comments submitted for the Electric Undergrounding Program, Phase 1 Application A.26-02-005, Cal Advocates shows that inclusion of avoided O&M in the denominator of the BCR as a negative cost—instead of the numerator as a benefit—is inconsistent with economic theory, the benefit-cost analysis literature, and best practice from government agencies. Cal Advocates also proves through mathematical and numeric exposition that placing avoided O&M in the denominator has a non-linear positive effect on the BCR, resulting in inflated BCRs compared to the standard formulation in which avoided O&M is included in the numerator.
For details, see: A.26-02-005, *Response of the Public Advocates' Office to 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, at 14-21. Accessed at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K305/608305683.PDF
Also see: A.26-02-005, *Reply Comments of the Public Advocates Office*, July 7, 2026, at 4-14. Accessed at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K354/610354677.PDF

[7] SCE RAMP Report, Chapter 4 Workpaper: *BCR Methodology for Covered Conductor and Targeted Undergrounding*, at WP-1.

taxes, asset retirement costs, and depreciation costs (including negative salvage value), among others.

SCE also excludes significant costs that will be incurred by customers as a result of SCE's capital mitigation proposals. As illustrated in Figure 1, a $1 billion capital investment recovered over 40 years can produce a capital-related revenue requirement of approximately $3.05 billion—roughly $2 billion more than the same $1 billion recovered as an operating expense, due to the total return paid by ratepayers.[8] This illustration does not include other additional capital-related program costs that are passed onto ratepayers, such as taxes and negative salvage value recovery.

FIGURE 1: Comparison of Timing of Cost Recovery of $1 Billion (Operating Expense Revenue Requirement versus Capital-Related Revenue Requirement)[9]



Because SCE's cost comparisons of mitigation alternatives do not reflect the full cost burden to ratepayers, the cost comparisons produce a misleading cost-benefit analysis for evaluating risk mitigation proposals.

---

[8] Figure 1 reflects depreciation and return on rate base only. It assumes the asset is financed entirely from equity (i.e., no debt), depreciation is on a straight-line basis with no asset salvage value, and no tax effects are included. See California Public Utilities Commission, Office of Governmental Affairs, *2025 Senate Bill 695 Report*, September 2025, Footnote 51 at 13. Accessed at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/2025-sb-695-report_093025.pdf.

[9] California Public Utilities Commission, Office of Governmental Affairs, *2025 Senate Bill 695 Report*, September 2025, at 14. Accessed at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/2025-sb-695-report_093025.pdf.

2. SPD should require SCE to supplement its RAMP filing with complete capital cost estimates so that the Commission can assess which mitigations provide the best cost-benefits for ratepayers.

SCE's exclusion of capital-related costs significantly understates what ratepayers will pay. SCE's BCR analysis inflates the cost-effectiveness of capital-intensive mitigation strategies, and makes O&M intensive mitigation appear to have a poorer BCR in comparison. Allowing SCE to exclude capital-related costs distorts the information that is meant to inform subsequent GRC proceedings. This inaccurate information can lead the Commission to approve mitigation measures that appear to be more cost-effective but can actually be more costly to ratepayers. A reasonable cost-benefit analysis should include estimates of all costs that ratepayers will bear.

For almost a decade now, the Commission has required utilities to identify two alternative risk mitigations that were considered for each RAMP proposal.[10] [11] The comparison of the costs and benefits of different risk mitigations and alternatives is a key element of the RAMP process; it allows the Commission and parties to see differences in costs and benefits, and why the utility views the alternatives as inferior to the proposed mitigation.[12] In order to reasonably evaluate the costs and benefits of alternatives, and to understand the impact that these mitigations would have on customer rates, the Commission and parties must know the full costs of mitigations by including those capital-related costs to ratepayers. To remedy SCE's exclusion, SPD should require SCE

---

[10] 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.").

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

[12] D.14-12-025 at 32. ("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.")

to revise its BCR calculations in a supplement to this RAMP, including estimates for all capital-related costs recovered from ratepayers when comparing mitigation alternatives.

B. SCE fails to evaluate the risk of idle or out-of-service transmission assets in its RAMP wildfire risk assessment.

Fires ignited by electric transmission equipment have produced some of the most severe consequences to the public in recent California history. The Camp Fire,[13, 14] Woolsey Fire,[15] Kincade Fire, and Eaton Fire each involved transmission equipment and resulted in loss of life, widespread property destruction, and billions of dollars in damages. The Kincade Fire burned more than 77,000 acres, destroyed 374 structures, and resulted in four injuries and $385 million in property damage.[16, 17] Further the Kincade Fire was also ignited by PG&E's idle transmission facilities.[18]

A joint investigation by the California Department of Forestry and Fire Protection (CAL FIRE) and the County of Los Angeles Fire Department concluded that electrical arcing on an out-of-service SCE transmission tower caused the January 2025 Eaton Fire. This fire burned 14,021 acres, destroyed 9,414 structures, and resulted in 19 fatalities and

---

[13] 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.)

[14] Aon, *2026 Climate and Catastrophe Insight*, 2026, at 9. Accessed at: https://www.aon.com/getmedia/3fd8e3d3-1e2f-4df8-89a8-d376b753b3a0/20260120-cci-2026.pdf.

[15] California Public Utilities Commission, Safety and Enforcement Division, Electric Safety and Reliability Branch, *Investigation Report of the Woolsey Fire*, at 1. Accessed August 27, 2026 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 the brush below.)

[16] 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 involved multiple violations of General Order 95 by PG&E transmission infrastructure.)

[17] Sonoma County, *2019 Kincade Fire After Action Report*, March 2020, at 9.

[18] California Public Utilities Commission, SED, *Administrative Consent Order*, November 1, 2021. Accessed at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M425/K880/425880669.pdf

approximately $25 billion in economic losses.[19, 20] The CAL FIRE investigation confirms that SCE's exclusion of idle transmission from wildfire risk assessment is unreasonable. And, while SCE acknowledges that the January 2025 wildfire events have "more fully informed" its view of transmission-level wildfire risk[21] and necessitated enhanced tail-risk modeling,[22] as an "emergent risk driver,"[23] SCE provides no discrete risk assessment or quantification for idle transmission. Instead, SCE excludes idle transmission lines from its wildfire risk assessment in this RAMP.[24]

---

[19] County of Los Angeles, Fact Sheet: Key Facts About the Eaton and Palisades Fires, at 1. Accessed August 27, 2026 at: https://file.lacounty.gov/SDSInter/lac/1199046_Eaton_Palisades_Fires_Anniversary_Fact_Sheet.pdf.

[20] Aon, *2026 Climate and Catastrophe Insight*, 2026, at 58. Accessed at: https://www.aon.com/getmedia/3fd8e3d3-1e2f-4df8-89a8-d376b753b3a0/20260120-cci-2026.pdf.

[21] SCE RAMP Report, Chapter 4: Wildfire and PSPS, at 23. ("…the recent January 2025 events, as well as SCE's new WIM, have more fully informed our view of wildfire risk that more broadly encompasses distribution-, sub transmission- and transmission-level assets within SCE's HFRA.")

[22] SCE RAMP Report, Chapter 4: Wildfire and PSPS, at 34. ("…based on Commission guidance as well as lessons learned from the January 2025 wildfire events, SCE has developed its new WIM. This enhanced WIM applies well-established spatial aggregation and mathematical scaling techniques to derive a full probability distribution of potential wildfire outcomes and associated natural unit consequences at the individual asset level. This modeling approach supports a more comprehensive representation of wildfire risk, including low-probability, high-consequence (i.e., tail risk) events, and is consistent with the Commission's emphasis on probabilistic risk assessment.")

[23] SCE RAMP Report, Chapter 4: Wildfire and PSPS, at 17, Footnote 31. ("The wildfire risks and mitigations are generally presented in RAMP based on historical information and experience. (An exception is the WIM-Climate, which incorporates forward-looking climate-related information, as explained above.) SCE respectfully notes that, on an ongoing basis, SCE continues to study and evaluate new information and developments that can influence the scope of wildfire risks, modeling, and/or mitigations. This includes disconnection, grounding, or removal, as appropriate, of idle facilities in HFRA as well as other emergent risk drivers and elements.")

[24] See SCE's July 16, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN01*, Question 5.a. ("The risk assessment in the RAMP does not separately account for idle transmission lines.")

1. SPD should require SCE to supplement its RAMP with a complete analysis of this risk.

SCE states that approximately 237 miles of idle transmission circuits in its service territory traverse high-fire risk areas (HFRA) for at least some of their length.[25] Yet SCE plans to remove less than 1/3 of these idle transmission lines in 2026 and 2027.[26, 27] That leaves approximately 161 miles of idle transmission circuits which SCE has permanently grounded rather than removed traversing HFRA.[28]

SCE's reliance on indefinite grounding for at least 161 miles of idle transmission in HFRA is inadequate. Nearby energized lines can induce voltage on de-energized, grounded idle lines through electromagnetic coupling.[29] The induced voltage can cause hazardous current flow, leading to arcing if there are faults, damaged insulation, or contact with vegetation on idle lines.[30, 31] These risks are exacerbated by SCE's poor

---

[25] See SCE's July 16, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN01*, Question 5.b. ("SCE has approximately 237 miles of idle transmission circuits that traverse HFRA for at least some of their length.")

[26] See SCE's July 16, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN01*, Question 5.c. ("SCE plans to remove approximately 76 miles of idle transmission lines in 2026 and 2027.")

[27] See SCE's August 18, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN03*, Question 1.b. ("Most of the 76 circuit miles of idle transmission lines that SCE is planning to remove are in HFRA, but some of the sections to be removed may traverse non-HFRA.")

[28] See SCE's July 16, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN01*, Question 5.c. ("SCE's general approach to idle lines is to permanently ground at endpoints and every two miles in sections that parallel energized transmission lines. All idle transmission lines that parallel energized circuits in HFRA are grounded consistent with this general approach.")

[29] Filsinger Energy Partners, *PG&E Independent Safety Monitor Status Update Report* (PG&E ISM Report), May 26, 2026, at 27. Accessed at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/ism-status-update-report-8.pdf.

[30] PG&E ISM Report at 27. ("Utilities have been performing substantial reviews of transmission failure modes relative to induction and structure grounding…Induction on idle transmission lines can create a wildfire threat because nearby energized lines can induce a voltage onto de-energized lines through electromagnetic coupling. This induced voltage can cause unexpected current flow, leading to arcing if there are faults, damaged insulation, or contact with vegetation on idle lines. PG&E states that unintended energization of idle lines is risky because its protective systems cannot identify performance issues that may be present (e.g., damaged equipment) until energization occurs.")

[31] SCE also acknowledges that removing idle line sections reduces induction risk. See SCE's August 18, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN03*, Question 1.b. ("Removing a section of an idle transmission line should reduce induction risk on the entire line.")

inspection practices. Despite the fact that grounded idle lines remain susceptible to induced voltage and arcing, idle transmission lines less are inspected frequently by SCE than energized lines.[32] Where in-service transmission overhead lines receive a detailed inspection every 36 months and a routine patrol annually, idle overhead lines receive detailed inspection only "as needed" and routine patrol every 36 months.[33] SCE also inspects its idle transmission lines less frequently than other IOUs. For example, PG&E conducts the same inspections on its idle lines as energized, in-service lines.[34]

Accordingly, there is an urgent need for SCE to expedite assessment and mitigation of wildfire risk from idle transmission assets in this RAMP to avoid future costly impacts on lives and property caused by such safety gaps in other locations. SPD should explicitly direct SCE to assess and quantify wildfire risk associated with its idle transmission assets in a supplement to this RAMP.

---

[32] See SCE's August 18, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN03*, Question 1.a, at attachment *Transmission Inspection and Maintenance Program_IN-4_8.2026*, Table 4-1.

[33] See SCE's August 18, 2026 response to Data Request *CalAdvocates-SCE-2026-RAMP-AYN03*, Question 1.a, at attachment *Transmission Inspection and Maintenance Program_IN-4_8.2026*, Table 4-1.

[34] PG&E ISM Report at 27. ("It should be noted that even though certain PG&E lines may be idle, these lines still receive the same asset inspections as those lines that are energized and in service.")

III. CONCLUSION

For the reasons stated herein, Cal Advocates recommends that SPD require SCE to supplement its RAMP Report to: (1) update its analysis of mitigation alternatives to include all capital-related costs recovered from ratepayers; and (2) explicitly assess and quantify the wildfire risk of idle transmission assets.

Respectfully submitted,

/s/ PETER CHAU
Peter Chau
Attorney for the

The Public Advocates Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102
Telephone: (415) 703-1682
Email: Peter.Chau@cpuc.ca.gov

September 4, 2026

APPENDIX A

DATA REQUEST:
CALADVOCATES-SCE-2026-RAMP-AYN01
QUESTION 5

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET P u b A d v - S C E - 2 0 2 6 - R A M P - A Y N 0 1

To: Public Advocates Office
Prepared by: Daniel Komula
Job Title: Senior Advisor
Received Date: 7/3/2026

Response Date: 7/16/2026

Question 05.a-d:
In Chapter 4: Wildfire and PSPS, SCE states in Footnote 31 that "on an ongoing basis, SCE continues to study and evaluate new information and developments that can influence the scope of wildfire risks, modeling, and/or mitigations. This includes disconnection, grounding, or removal, as appropriate, of idle facilities in HFRA as well as other emergent risk drivers and elements."

a. Please describe whether and how SCE's risk assessment accounts for idle, retired, or decommissioned transmission lines that have not been physically removed from the system.
b. Please identify the number of miles and/or structures of idle, retired, or decommissioned transmission lines currently located within SCE's HFRA that have not been physically removed.
c. Referring to Question 5.b., please describe and provide details on SCE's plan to address the idle, retired, or decommissioned transmission lines identified in that response, including the criteria SCE uses to prioritize which facilities are disconnected, grounded, or removed, and the expected timeline for doing so.
d. Please describe whether SCE has experienced any wildfire ignitions, public safety incidents, or near-misses attributable to idle or decommissioned transmission facilities in the past ten years, and if so, provide relevant details.

Response to Question 05.a-d:

a) *Please describe whether and how SCE's risk assessment accounts for idle, retired, or decommissioned transmission lines that have not been physically removed from the system.*
   - The risk assessment in the RAMP does not separately account for idle transmission lines. As noted in Chapter 4, Footnote 31, SCE continues to evaluate emergent risk drivers and elements, including idle lines in HFRA. Please note that SCE does not have retired or decommissioned transmission lines that have not been physically removed from the system.

b) *Please identify the number of miles and/or structures of idle, retired, or decommissioned transmission lines currently located within SCE's HFRA that have not been physically removed.*
   - SCE has approximately 237 miles of idle transmission circuits that traverse HFRA for at least some of their length. Please see SCE's response to Question 5.a.

c) *Referring to Question 5.b., please describe and provide details on SCE's plan to address the*

idle, retired, or decommissioned transmission lines identified in that response, including the criteria SCE uses to prioritize which facilities are disconnected, grounded, or removed, and the expected timeline for doing so.

- SCE's general approach to idle lines is to permanently ground at endpoints and every two miles in sections that parallel energized transmission lines. All idle transmission lines that parallel energized circuits in HFRA are grounded consistent with this general approach. In addition, SCE plans to remove approximately 76 miles of idle transmission lines in 2026 and 2027. SCE prioritizes idle line mitigations based on various factors, including location (whether the line is in HFRA) and whether the line parallels energized lines. Please see SCE's response to Question 5.a.

d) *Please describe whether SCE has experienced any wildfire ignitions, public safety incidents, or near-misses attributable to idle or decommissioned transmission facilities in the past ten years, and if so, provide relevant details.*

- SCE objects to this request under Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that the request for "any… wildfire ignitions, public safety incidents or near-misses" is vague and ambiguous and the burden to SCE of identifying all potentially responsive information outweighs the benefit of producing the information. Subject to and without waiving these objections, SCE responds that it is aware of certain public safety incidents involving idle SCE transmission facilities. For example, there was a fatality incident in 2020 involving a member of the public who climbed an idle, out-of-service transmission tower and fell off. SCE also notes that its privileged investigation related to the Eaton Fire is ongoing. SCE's public disclosures have indicated that, while SCE has not conclusively determined that its equipment caused the ignition of the Eaton Fire, a potentially viable explanation is that a de-energized idle SCE transmission facility in the preliminary area of origin may have been associated with the ignition of the fire.

APPENDIX B

DATA REQUEST:
CALADVOCATES-SCE-2026-RAMP-AYN03
QUESTION 1

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET P u b A d v - S C E - 2 0 2 6 - R A M P - A Y N 0 3

To: Public Advocates Office
Prepared by: Melaney Thiel
Job Title: Sr Prj Mgr
Received Date: 8/4/2026

Response Date: 8/18/2026

Question 01.a-d:
Referring to Data Request number CalAdvocates-SCE-2026-RAMP-AYN01, Question 5.c., SCE responded that "its general approach to idle lines is to permanently ground at endpoints and every two miles in sections that parallel energized transmission lines. All idle transmission lines that parallel energized circuits in [High Fire Risk Area] HFRA are grounded consistent with this general approach. In addition, SCE plans to remove approximately 76 miles of idle transmission lines in 2026 and 2027. SCE prioritizes idle line mitigations based on various factors, including location (whether the line is in HFRA) and whether the line parallels energized lines…"1

a. Please provide all policies, standards, and procedures that govern SCE's management of idle transmission lines.
b. Please explain whether all of the 76 miles of the planned idle transmission lines to be removed are in HFRA?
c. Please provide an excel spreadsheet listing of all of SCE's idle transmission circuits including: line designation, length, HFRA or not, parallel to energized lines, line removal initiation and completion dates.
d. If SCE have a standard document that captures all this information, please provide it.

Response to Question 01.a-d:

a. SCE complies with General Order (G.O.) 95, Rule 31.2, "Inspection of Lines" and Rule 31.6, "Abandoned Lines." Idle transmission lines are inspected and maintained according to SCE's Transmission Operations and Maintenance Policies and Procedures Manual (TOM) and the Transmission Inspection and Maintenance Program (TIMP) manual. Please also see SCE's Transmission Idle Line Review Committee (TILR) Charter and System Operating Bulletin (SOB 25).
b. Most of the 76 circuit miles of idle transmission lines that SCE is planning to remove are in HFRA, but some of the sections to be removed may traverse non-HFRA. Please note that SCE has removed one idle transmission line, Santa Barbara-San Marcos-Vegas, that was included in the 76 miles of planned removals identified in response to CalAdvocates-SCE-2026-RAMP-AYN01. Please also note that some of the targeted removals are sections of idle transmission lines and some of the targeted removals are entire idle transmission lines. Removing a section of an idle transmission line should reduce induction risk on the entire line.
c. Please see the attached spreadsheet. Please note that the spreadsheet contains only 73.6 miles of idle transmission lines due to removal of the Santa Barbara-San Marcos-Vegas line.

Please also note that SCE categorizes idle transmission lines by "proximity" to high-voltage (>55kV) energized facilities rather than "parallel" to energized lines. Proximity includes idle transmission lines that parallel energized lines plus idle transmission lines that are close but not parallel to energized lines, such as crossings. Please also note that the spreadsheet reflects SCE's current plans with respect to specific idle transmission lines and line sections targeted for removal, which may change as SCE continues to assess idle transmission lines and refines its work planning based on resources, permitting, and other requirements.

d. n/a, see attached documents.

APPENDIX C

DATA REQUEST:
CALADVOCATES-SCE-2026-RAMP-AYN03
QUESTION 1, ATTACHMENT:
TRANSMISSION INSPECTION AND MAINTENANCE PROGRAM_IN-4_8.2026

IN–4: Inspection Frequencies

1.0 Transmission

Table 4–1: Transmission Inspection Frequencies

Facility/Equipment	Detailed Inspection	Patrol (Routine)	Patrol (Emergency)	Insulator Wash
Transmission Overhead Lines	36 months[a/]	Annually[b/]	As Needed	As Needed [a/]
Idle[c/] Overhead Lines	As Needed	36 months	As Needed	As Needed[d/]
Underground Lines and Vaults	36 months[e/ g/]	Annually[e/ f/]	As Needed	N/A
Idle[c/] Underground Lines/Vaults	As Needed	36 months[g/]	N/A	N/A

[a/] The decision to wash or not wash is determined by Grid Supervision and is based on general knowledge and experience of a geographical area combined with the particular local conditions. Generally, polymer insulators do not require routine washing.

[b/] Performed by air on alternate years (if-necessary). Includes areas designated by the CPUC as Tier 3 and Tier 2 High Fire-Threat District and areas designated by SCE as High Fire Area.

[c/] Lines and Line segments are considered idle after being declared "Out of Service."

[d/] Lines and Line segments declared "Out of Service" are not subject to insulator washing.

[e/] Includes inspection of "pressurized piped cables" three to four times annually to check valves, pumps, and alarms, record pressure readings; and verify the cathodic protection is operational.

[f/] Only those lines and line elements visible above ground level.

[g/] Includes vault or enclosure entry.

Note(s):

1. Lattice towers in high-wind areas are subjected to additional Maintenance, including but not limited to ascending/descending towers, ringing steel members, and tightening hardware. May perform supplemental inspections in areas designated by the CPUC as Tier 2 and Tier 3 High Fire-Threat District and areas designated by SCE as High Fire Area.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Application Of Southern California Edison Company (U338E) Regarding 2026 Risk Assessment Mitigation Phase.	**Application 26-05-018** **(Filed May 15, 2026)**

ENERGY PRODUCERS AND USERS COALITION INFORMAL COMMENTS ON SOUTHERN CALIFORNIA EDISON COMPANY'S RISK ASSESSMENT MITIGATION PHASE APPLICATION

James P. Mosher
Colin Fitzhenry
Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017
Tel.: (636) 898-6725
jmosher@consultbai.com
cfitzhenry@consultbai.com

Consultants to the Energy Producers and Users Coalition

Nora Sheriff
Antonio P. Carrejo
Buchalter LLP
425 Market Street, 29th Floor
San Francisco, CA 94105-2491
415.227.3551 office
nsheriff@buchalter.com
acarrejo@buchalter.com

Counsel for the Energy Producers and Users Coalition

September 4, 2026

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. COMMENTS 2

A. WILDFIRE AND PSPS RISK ANALYSIS 2

1. SCE's Consequence Scalars Function as a Non-Neutral Risk Adjustment Mechanism 2

2. Transition from Segment-Level to Circuit-Level RRUs Risks Obscuring Cost-Ineffective Bundling 4

3. Failure to Quantify Lifecycle Revenue Requirement Costs for WCCP and TUG 6

4. Evaluation of De-Energization, Grounding and Idle Asset Removal Should be Required for RAMP Evaluation of Wildfire Risk 7

5. Conflation of Lower-Cost Operational Mitigations with Low-BCR Programs 9

6. Disaggregation of Safety and Avoided PSPS Reliability Benefits 10

B. HYDRO ASSET FAILURE 11

1. Downward Skew in Expected-Value Risk Modeling and Tranching Granularity 11

2. Selection of Lower-BCR Hydro Mitigation Plans and Workpaper Data Omissions 13

III. CONCLUSION 15

Attachment A: Data Request Responses A-1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Application Of Southern California Edison Company (U338E) Regarding 2026 Risk Assessment Mitigation Phase.	**Application 26-05-018** **(Filed May 15, 2026)**

ENERGY PRODUCERS AND USERS COALITION INFORMAL COMMENTS ON SOUTHERN CALIFORNIA EDISON COMPANY'S RISK ASSESSMENT MITIGATION PHASE APPLICATION

The Energy Producers and Users Coalition (EPUC)[1] submits these informal comments to the May 15, 2026, *Application Of Southern California Edison Company Regarding 2026 Risk Assessment Mitigation Phase* (RAMP).[2]

I. INTRODUCTION

The Commission's Risk-Based Decision-Making Framework (RDF) established a monetized risk quantification framework requiring utilities to evaluate risk mitigations using Benefit-Cost Ratios (BCRs) grounded in an expected-value formulation.[3] In its 2026 RAMP, Southern California Edison Company (SCE) presents its grid hardening and wildfire risk mitigation strategy utilizing its updated Wildfire Integrated Model (WIM).[4] The WIM incorporates stochastic tail-risk estimation, asset-level spatial resolution, and location-specific

[1] EPUC represents the electricity end-use interests of the following companies in this proceeding: California Resources Corp., PBF Holding Company, and Tesoro Refining & Marketing Company LLC.
[2] The August 6, 2026 *Assigned Commissioner's Scoping Memo and Ruling* in A.26-05-018 indicates that informal comments are due on September 4 to the Safety Policy Division and the RAMP service list.
[3] *See* D.21-11-009, D.22-12-027, D.24-05-064, and D.25-08-032.
[4] *See Application of Southern California Edison Company Regarding 2026 Risk Assessment Mitigation Phase* (Application), A.26-05-018, May 15, 2026 at 6.

qualitative adjustments.[5] Wildfire and Public Safety Power Shutoff (PSPS) mitigations, predominantly Covered Conductor (CC) and Targeted Undergrounding (TUG), form the largest share of SCE's proposed safety-related capital expenditures.[6] Before SCE files its Test Year 2029 General Rate Case (GRC), the Commission must verify that the utility's quantitative models, Risk Reduction Unit (RRU) boundaries, and asset cost assumptions comply with the Commission's cost-effectiveness standards. The Commission must further ensure that these inputs accurately reflect, rather than obscure, the impacts borne by ratepayers.

II. COMMENTS

A. WILDFIRE AND PSPS RISK ANALYSIS

1. SCE's Consequence Scalars Function as a Non-Neutral Risk Adjustment Mechanism.

The Risk-Based Decision-Making Framework (RDF) establishes that baseline risk assessments and Benefit-Cost Ratio (BCR) rankings must adhere to a standardized, risk-neutral expected-value framework unless explicit deviations are approved.[7] SCE incorporates qualitative demographic and geographic scaling factors (i.e., multipliers or consequence scalars) such as Access and Functional Needs (AFN), Non-Residential Critical Infrastructure (NRCI), and Community Fire Risk Assessment (CFRA)/Egress into its quantitative Wildfire and PSPS risk calculations.[8] SCE asserts that these adjustments maintain a "risk-neutral" posture because

[5] *Id.* at 16.
[6] Southern California Edison Company, Risk Assessment and Mitigation Phase, *Overhead Equipment Failure*, Chapter 5, May 15, 2026 at 20.
[7] *See* D.25-08-032, *Phase 4 Decision*, R.20-07-013, Aug. 29, 2025, Appendix A at A-10.
[8] Southern California Edison Company, Risk Assessment and Mitigation Phase, *Wildfire and PSPS*, Chapter 4, May 15, 2026 at 101-102.

they do not alter the underlying consequence probability distribution generated by its Wildfire Integrated Model (WIM) or apply non-linear tail-event amplification.[9]

However, in response to Data Request (DR) SPD-SCE-2026-RAMP-004 Q.42a–b, SCE seeks to distinguish between risk-aversion scaling functions and consequence scalars:

> Scalars should not be confused with a risk-scaling function applied to the full consequence distribution. A risk function alters the probability or weighting of extreme outcomes across the distribution, such as through tail-event amplification, whereas a risk scalar adjusts the valuation of consequences for specific populations or geographies without modifying the underlying probability distribution.[10]

SCE further clarifies that it applies AFN, NRCI, and CFRA multipliers to safety risk consequences post-modeling.[11] However, in its response to DR SPD-SCE-2026-RAMP-004 Q.14a–b, SCE confirms the operational effect of these consequence scalars on mitigation cost-effectiveness determinations:

> The addition of these scalars could result in marginal BCRs exceeding 1.0 in areas where social vulnerability or egress-related factors are present.[12]

SCE asserts that consequence scalars are applied upstream and are unlikely to alter relative rankings between competing hardening options on the same circuit.[13] However, as SCE expressly admits, applying multiplicative weights to selected consequences directly can impact whether a mitigation is deemed cost-effective (i.e., whether the scaled BCR > 1.0). Scaling consequence values for designated populations or geographies functions in practice as a risk-

[9] *See* Data Request (DR) SPD-SCE-2026-RAMP-004 Q.42a–b, Jun. 24, 2026 (Attachment A - Page 2).
[10] *Ibid*.
[11] *Ibid.*
[12] DR SPD-SCE-2026-RAMP-004 Q.14a–b, Jun. 19, 2026 (Attachment A - Page 3-4)
[13] *Id.* at Attachment A - Page 4.

weighting mechanism that allows previously non-cost-effective projects (BCR < 1.0) to be included in the GRC as cost-justified.

SPD should recommend that SCE identify in its 2029 GRC application all wildfire Risk Reduction Units (RRUs), and individual circuit segments within each RRU, where the application of AFN, NRCI, CFRA/Egress or other such scalars elevated an otherwise below 1.0 BCR to above 1.0. This will ensure full transparency in workpapers where this scaling impact is not made readily apparent.

2. Transition from Segment-Level to Circuit-Level RRUs Risks Obscuring Cost-Ineffective Bundling

In prior RAMP and Wildfire Mitigation Plan (WMP) cycles, California utilities evaluated and executed grid hardening at the discrete circuit-segment level.[14] Such granularity allowed the Commission to assess an electric utility matching of proposed capital expenditures with the highest-risk portions of the utility's overhead distribution infrastructure. In this RAMP, SCE transitions from the historical circuit segment level to evaluating hardening at the aggregated whole-circuit (RRU) level.[15] This methodological shift evaluates whether all remaining unhardened portions of a circuit should be mitigated in aggregate, rather than prioritizing individual high-risk segments.

In its response to DR SPD-SCE-2026-RAMP-004 Q.38, SCE provides the logistical rationale for its less-granular approach:

---

[14] *See* Office of Energy Infrastructure Safety, *2025 Wildfire Mitigation Plan Updates Guidelines*, Jan. 2024 at 6 (requiring utilities to analyze their "highest-risk circuits, segments, or spans"); *see also* Southern California Edison Company, Risk Assessment and Mitigation Phase, *Wildfire and PSPS*, Chapter 4 at 38-39.

[15] *See* Southern California Edison Company, Risk Assessment and Mitigation Phase, *Wildfire and PSPS*, Chapter 4 at 38-39.

> The segment-level approach has left many circuits with non-contiguous, partially hardened segments, creating artificial stop-and-start points for mitigation activities and embedding execution inefficiencies into the remaining scope.
>
> Segment-level hardening was a reasonable risk-reduction strategy when a large portion of SCE's overhead system remained unhardened and incremental risk reductions were higher than current estimates. However, practical execution constraints and the evolution of hardening strategies have materially reduced the marginal risk reduction achievable through continued application of this approach.
>
> Shifting to a circuit-level RRU provides a more decision-relevant framework by evaluating whether the remaining unhardened portions of a circuit should be addressed in aggregate, rather than in isolation.[16]

While operational continuity and construction efficiencies are valid planning considerations, evaluating unhardened circuit segments in the aggregate risks masking cross-subsidization of cost-ineffective mitigation segments by cost-effective mitigation segments. By averaging risk scores and mitigation costs across a whole circuit, low-risk segments that would fail a standalone cost-effectiveness test receive capital hardening funding by freeriding on the elevated risk scores of adjacent high-risk segments. Aggregate bundling of segments for project funding purposes should only be permitted up to the point where the BCR of the aggregate bundled project matches or just exceeds the weighted-average BCR of the individual segment subprojects. In other words, the bundled project must show economies of scale or other project execution efficiencies that justify bundling. In addition, in no instance should a bundled project be proposed for funding if its BCR falls below 1.0.[17]

---

[16] DR SPD-SCE-2026-RAMP-004 Q.38, June 24, 2026 (Attachment A - Page 5).

[17] *See example* Resolution SPD-37, *Update and Revision of Senate Bill 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations*,

SPD should recommend that SCE provide in its 2029 GRC filing the disaggregated BCRs of individual sub-projects constituting a bundled project, including costs, and monetized risk profiles at both the circuit level and for each circuit segment comprising the RRU. This granular data is vital to enable the Commission and intervenors to assess whether SCE is diluting wildfire risk mitigation cost-effectiveness by bundling low-risk circuit segments into expensive capital hardening programs without commensurate risk reduction.

3. Failure to Quantify Lifecycle Revenue Requirement Costs for WCCP and TUG

Capital-intensive wildfire mitigations, such as the Wildfire Covered Conductor Program (WCCP) and Targeted Undergrounding (TUG), involve long-lived utility assets that impose revenue requirement obligations spanning decades. Assessing cost-effectiveness based solely on upfront capital expenditure and near-term O&M understates the full lifecycle cost to ratepayers. Full lifecycle costs include return on rate base, depreciation, income taxes, property taxes, and asset retirement obligations.

In its response to DR PubAdv-SCE-2026-RAMP-AYN02 Q.02a–n, SCE confirmed that it has not performed a comprehensive net present value (NPV) lifecycle revenue requirement analysis for either WCCP or TUG:

> SCE has not performed the comprehensive lifecycle cost analysis requested for the Wildfire Covered Conductor Program ('WCCP') or Targeted Undergrounding ('TUG') and therefore does not possess a document, study, testimony exhibit, workpaper, or analysis that separately quantifies each of the cost categories identified in subparts (a) through (n)... The RAMP framework does not require utilities to separately calculate, forecast, or present the full lifecycle revenue requirement impacts associated with

Dec. 4, 2025 at 16 ("Allowing undergrounding projects that have forecasted CBRs below 1.0 to be included in a Phase 2 Application would be unreasonable.").

> proposed mitigations, including detailed breakdowns of capital costs, maintenance costs, operations costs, depreciation, cost of capital, taxes, negative salvage, asset retirement obligations, end-of-life disposal costs, or other ratemaking elements requested here.[18]

Because the RDF does not yet formally mandate full lifecycle revenue requirement modeling in RAMP reports, SCE's RAMP BCR calculations do not reflect the complete financial impact on ratepayers over asset lifespans. Omitting long-term financing costs, depreciation, and tax gross-ups distorts comparisons between long-lived, capital-intensive undergrounding and alternatives with lower capital profiles and resulting revenue requirements.

Until the RDF is refined to explicitly require full lifecycle revenue requirement modeling in RAMP reports, SPD should recommend that SCE be required to submit NPV lifecycle revenue requirement BCRs alongside its preferred BCR calculations. SCE should be required to present these results for all major wildfire risk mitigations proposed in its forthcoming 2029 GRC application.

4. Evaluation of De-Energization, Grounding and Idle Asset Removal Should be Required for RAMP Evaluation of Wildfire Risk

De-energized and idle overhead electric facilities in High Fire Risk Areas (HFRAs) represent a public safety hazard, even if not actively energized during normal operating conditions. During extreme wind events, ungrounded or abandoned lines can be energized through induction, direct contact with energized circuits, or experience structural failure, all contributing to ignition risks especially in HFRA. Evaluating the decommissioning, grounding, or

[18] DR PubAdv-SCE-2026-RAMP-AYN02 Q.02a–n, Aug. 7, 2026 (Attachment A - Page 7-8).

complete removal of idle facilities is essential for eliminating baseline wildfire risks and minimizing recurring maintenance costs.

In its response to DR PubAdv-SCE-2026-RAMP-AYN01 Q.06a–b, SCE acknowledged that it has not budgeted or forecasted costs in its 2026 RAMP Report or committed to their inclusion in its upcoming GRC application for disconnecting, grounding, or removing idle transmission lines located in HFRAs:

> SCE has not specifically budgeted or forecasted costs in RAMP or the upcoming GRC for disconnecting, grounding, or removing idle transmission lines in HFRA. SCE may include some of these costs in the upcoming 2029 GRC but SCE does not know when the costs will be finalized. They may not be finalized until shortly before SCE files the 2029 GRC.[19]

In the same response, SCE provided unit cost benchmarks, estimating grounding work at approximately $6,900 per ground installation and circuit removal (conductor only) at approximately $292,000 per circuit mile.[20] Deferring the evaluation of idle facility de-risking until immediately prior to the 2029 GRC filing deprives the Commission and stakeholders of the opportunity to review the risk-reduction efficiency of these programs within the RAMP.

SPD should recommend that the Commission require SCE to file a comprehensive inventory in its 2029 GRC of all idle transmission and distribution facilities located within Tier 2 and Tier 3 HFRAs; along with complete cost-effectiveness and risk analyses for both (1) grounding and (2) fully removing each identified facility.

[19] DR PubAdv-SCE-2026-RAMP-AYN01 Q.06a–b, Jul. 16, 2026 (Attachment A - Page 9).
[20] *Id. at* Attachment A - Page 9-10.

5. Conflation of Lower-Cost Operational Mitigations with Low-BCR Programs

The Commission's current RDF framework evaluates mitigation options based on BCR to ensure ratepayer funds achieve maximum safety benefit per dollar spent.[21] Proactive capital replacement programs often carry high expenditures, whereas periodic operational and maintenance programs may achieve substantial risk reduction at significantly lower costs.

In its response to DR SPD-SCE-2026-RAMP-005 Q.30, when asked how it balances high-cost proactive hardening against lower-cost operational mitigations where individual BCRs appear low, SCE stated:

> SCE determined the balance between proactive hardening and operational mitigations based on overall risk reduction (LoRE × CoRE) rather than individual program BCRs. Proactive investments were prioritized to reduce underlying failure drivers and deliver sustained risk reduction, while operational and maintenance programs were designed to reflect compliance obligations.
>
> As a result, higher BCR investments are used to target the highest concentrations of risk within the system, **while lower BCR programs** can still be required to meet existing CPUC or other regulatory or legal requirements.[22]

SCE's rationale conflates "lower-cost" programs, the subject of SPD's inquiry, with "lower-BCR" programs. The two are not necessarily identical. Low-cost operational programs can yield superior BCRs if modest expenditures eliminate significant risks. Prioritizing proactive capital investments based on gross absolute risk reduction (LoRE * CoRE) while relegating

[21] *See* D.25-08-032 at 3 ("California ratepayers deserve operational excellence from their utility systems and this requires safety investments that are effective and strategic in getting the most value for their dollar.").
[22] DR SPD-SCE-2026-RAMP-005 Q.30, Jun. 19. 2026 (Attachment A - Page 11) (emphasis added).

operational programs to baseline compliance biases the mitigation portfolio toward capital-intensive grid replacement at higher ratepayer expense.

SPD should recommend that SCE amend its overhead asset evaluation framework for the 2029 GRC to provide complete BCR and NPV revenue requirement cost analyses across both capital hardening and non-capital operational/maintenance alternatives. Doing so will help ensure that low-cost operational programs are evaluated on their true cost-effectiveness merits rather than dismissed as mere compliance baselines.

6. Disaggregation of Safety and Avoided PSPS Reliability Benefits

SCE's grid-hardening strategy relies heavily on the monetized reliability benefits of avoided PSPS events to economically justify capital-intensive mitigations like Targeted Undergrounding in preference over cheaper alternatives like Covered Conductor. While PSPS de-energizations do entail significant customer disruption and service reliability impacts, direct wildfire safety risks involve catastrophic ignitions, property destruction, and loss of life. Bundling these distinct risk attributes into aggregated circuit-level BCRs can obscure whether expensive capital spending is being driven by direct safety risk reduction or by customer reliability and financial loss consequences.

In its response to DR SPD-SCE-2026-RAMP-004, SCE acknowledges the interaction between PSPS elimination, customer reliability, and safety modeling across circuit analyses.[23] When undergrounding is selected over covered conductor primarily due to PSPS reliability impact avoidance, capital expenditures are committed to solve an operational reliability issue

[23] *See* DR SPD-SCE-2026-RAMP-004 Q.38, June 24, 2026 (Attachment A - Page 5).

that could be mitigated through operational alternatives, customer-side generation, or microgrids at lower cost.

SPD should recommend that SCE explicitly disaggregate direct safety risk reduction benefits from avoided PSPS reliability and financial impact benefits in all circuit-level BCR calculations presented in the 2029 GRC. For any circuit where undergrounding is selected over covered conductor based on PSPS elimination, SCE must demonstrate that operational switching thresholds and customer-side reliability alternatives were evaluated on an equivalent lifecycle BCR basis; such alternatives include microgrids and backup generation.

SPD should also ensure that SCE's derivation of Interruption Cost Estimator (ICE) Customer Minutes Interrupted (CMI) values reflect both the complexion of the HFRA customer counts (i.e., Residential and Non-Residential) impacted by PSPS events as well as the Value of Service (VOS). The VOS in particular should be a composite of VOS for each customer class based on the counts in the specific HFRA analyzed, not a system-wide value that blends HFRA and non-HFRA VOS.

B. HYDRO ASSET FAILURE

1. Downward Skew in Expected-Value Risk Modeling and Tranching Granularity

Hydroelectric dam failure represents a classic low-likelihood, high-consequence risk where catastrophic failure is extremely rare, but potential property damage and loss of life are severe. Under the Commission's standard expected-value framework (multiplying annual failure likelihood by monetized consequence), near-term risk values appear low, driving calculated BCRs for high-cost civil safety controls close to near-zero. To manage this anomalous

outcome in its RAMP, SCE treated all 26 of its high-hazard dams as separate, individual tranches, rather than utilizing the standard RDF quintile grouping methodology.[24]

In its response to DR SPD-SCE-2026-RAMP-005 Q.70a–c, SCE explains the downward skew inherent in the standard expected-value BCR calculation:

> SCE is mandated to use the expected value for evaluation of risk reduction benefits in calculating BCR. This skews BCRs lower downward for low likelihood-high consequence events such as dam failure.[25]

In responding to DR SPD-SCE-2026-RAMP-005 Q.85a, SCE defended creating 26 discrete tranches rather than adopting a quintile tranching approach:

> While it is possible to group two or more dams in a single quintile using the recommended Quintile Approach, the dams themselves do not share homogenous risk profiles. Each dam differs greatly in location, size, height, and construction material. Therefore, the mitigations and controls for individual dams that are within the same tranche, will likely be unique to the individual dams.[26]

While dams possess unique physical and structural attributes, subdividing the entire portfolio into 26 standalone tranches eliminates comparative risk ranking across the fleet and impedes programmatic oversight of hydro mitigation expenditures.

SPD should recommend that SCE present both its 26-tranche methodology and the standard RDF quintile tranching methodology in its 2029 GRC filing. SCE should provide BCR calculations under both approaches, quantify material differences between them, and

[24] *See* SCE, Risk Assessment and Mitigation Phase, *Hydro Asset Failure,* Chapter 13, May 15, 2026 at 23.
[25] DR SPD-SCE-2026-RAMP-005 Q.70a–c, Jun. 19. 2026 (Attachment A - Page 12).
[26] DR SPD-SCE-2026-RAMP-005 Q.85a, Jun. 19, 2026 (Attachment A - Page 13); *see also* Southern California Edison Company, Risk Assessment and Mitigation Phase, *Hydro Asset Failure*, Chapter 13, May 15, 2026 at 22.

demonstrate how the single-dam approach produces superior risk mitigation outcomes for ratepayers.

2. Selection of Lower-BCR Hydro Mitigation Plans and Workpaper Data Omissions

In the RAMP filing, utilities are required to evaluate their proposed mitigation plan alongside at least two realistic alternative plans, presenting the relative costs, risk reductions, and BCRs for each option.[27] For Hydro Asset Failure, SCE's modeling indicated that both of the alternative portfolios evaluated produced higher BCRs than SCE's Proposed Plan.[28] In addition, SCE declined to provide standard workpaper data tables detailing the underlying cost and benefit components of its hydro alternative plans.

In its response to DR SPD-SCE-2026-RAMP-007 Q.04a–b, SCE explained its rationale for selecting a lower-BCR proposed plan versus the evaluated alternatives:

> SCE is required to use expected-value methodology for evaluation of risk reduction benefits, which produces lower BCRs for low-likelihood, high-consequence events such as dam failure. As a result, all three plans (proposed and both alternative plans) yield BCRs below 1.0 The marginal differences among them do not, on their own, support selection of an alternative over the Proposed Plan.[29]

SCE noted that Alternative Plan #1 involved capital expenditures not strictly mandated by dam safety regulators (FERC or DSOD), while Alternative Plan #2 relied on dam divestitures and decommissioning that face lengthy regulatory approvals.[30] However, when requested in DR

[27] D.25-08-032 at 121.
[28] Southern California Edison Company, Risk Assessment and Mitigation Phase, *Hydro Asset Failure*, Chapter 13, May 15, 2026 at 47-48.
[29] *See* DR SPD-SCE-2026-RAMP-007 Q.04a–b, Jun. 17, 2026 (Attachment A - Page 14).
[30] *Id. at* Attachment A - Page 14-15.

SPD-SCE-2026-RAMP-009 Q.02a to provide standard data tables containing the benefits and costs for these alternative plans, SCE stated:

> SCE is not aware of any requirement to provide the information requested in the data tables for the alternative plans for any risk, including Wildfire. SCE has provided the excel model files for the alternative plans that can be used to calculate BCRs for Hydro Asset Failure.[31]

Withholding standardized data tables for alternative plans limits the Commission's and parties' ability to assess whether SCE's Proposed Plan represents the most cost-effective approach for addressing hydro asset safety. While the RDF permits SCE to consider factors other than BCR when proposing mitigations, it does not relieve SCE from the obligation to be fully transparent about its analysis of proposed mitigations and viable alternatives. The data table for the alternatives provide the Commission, SPD and parties with valuable context for assessing the appropriateness of SCE's proposed mitigations, especially for extreme tail-risk events such as dam failures.

SPD should direct SCE to provide in its 2029 GRC filing a comprehensive evidentiary justification for why it has proposed a hydro mitigation portfolio with a lower BCR than available alternatives, especially after applying its tail-risk scaling function. Furthermore, SCE should be required to provide fully-populated cost and benefit workpaper tables for all alternative mitigations considered across all enterprise risks, enabling transparent verification of SCE's mitigation portfolio selection.

[31] *See* SPD-SCE-2026-RAMP-009 Q.02a., Jun. 30, 2026 (Attachment A - Page 16).

III. CONCLUSION

For the reasons set forth above, the Energy Producers and Users Coalition urge the Safety Policy Division to incorporate these recommendations into its Staff Evaluation Report. SPD should recommend that SCE provide transparent, disaggregated, and complete lifecycle cost-effectiveness data in its forthcoming 2029 GRC application. Further, SPD should recommend that SCE eliminate obfuscation of low-risk circuit segment bundling, provide full NPV revenue requirement analyses, justify lower-BCR proposed plans, and supply comprehensive workpaper data tables. These requirements are essential to ensuring that SCE's safety mitigations as proposed in its RAMP are genuinely cost-effective, analytically sound, and not unduly burdensome to California ratepayers.

Respectfully submitted,

BUCHALTER LLP

By:



Nora Sheriff

Counsel for the Energy Producers and Users Coalition

September 4, 2026

ATTACHMENT A

Energy Producers and Users Coalition
Informal Comments on the SCE 2026 RAMP

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 4

To: SPD
Prepared by: Bryan Landry
Job Title: Senior Advisor, Enterprise Risk Management
Received Date: 6/4/2026

Response Date: 6/24/2026

Question 42.a-b:
SCE states that "all risk baseline risk estimates and resulting BCR calculations presented in this 2026 RAMP are based on a risk-neutral view" (bold original, p. 8). This statement appears to conflict with SCE's separate application of risk attribute scalars (including AFN, NRCI, and CFRA scalars) to the safety attribute within the same BCR calculations. Does SCE's use of the term "risk-neutral" here refer narrowly to the absence of a non-linear risk-aversion function (i.e., no tail-event amplification of the probability-consequence distribution) or broadly to the absence of any risk-scaling adjustment to the underlying risk values?

a. If SCE uses "risk-neutral" in the narrow sense, confirm that SCE nonetheless applies the AFN, NRCI, CFRA, and other risk attribute scalars to the BCR calculations presented in SCE's 2026 RAMP.

i. Identify all risk-attribute scalars applied to BCR calculations in SCE's 2026 RAMP.

b. Explain SCE's basis for characterizing the BCR calculations as "risk-neutral" given that risk attribute scalars, which adjust the monetized value of safety consequences based on customer vulnerability, critical infrastructure concentration, and community fire exposure are applied to those same calculations.

i. In particular, identify how SCE distinguishes between (1) a risk function (which alters the probability-weighted treatment of outcomes), and (2) a risk scalar (which alters the valuation of consequences for specific populations or geographies).

ii. Explain why SCE considers the application of risk scalars to be consistent with a "risk-neutral view."

Response to Question 42.a-b:

a. Yes. SCE's use of the term "risk-neutral" refers narrowly to the absence of a non-linear risk-aversion function (i.e., no tail-event amplification of the probability–consequence distribution), consistent with the Risk-Based Decision-Making Framework (RDF) definition of risk attitude (Appendix A).[1]

   SCE uses "risk-neutral" in this narrow sense to refer to the absence of a non-linear risk-aversion function (i.e., no tail-event amplification of extreme outcomes).

[1] California Public Utilities Commission. (2023). *Risk-Based Decision-Making Framework (RDF) Phase IV Decision*, Appendix A (Risk Attitude Definitions).

Scalars should not be confused with a risk-scaling function applied to the full consequence distribution. A risk function alters the probability or weighting of extreme outcomes across the distribution, such as through tail-event amplification, whereas a risk scalar adjusts the valuation of consequences for specific populations or geographies without modifying the underlying probability distribution.

Under SCE's approach, the underlying probability–consequence structure produced by the Wildfire Integrated Model (WIM) is preserved, and any adjustments are applied only after the model has generated its results. Specifically, SCE applies post-model consequence adjustments through attribute-specific scalars, including the AFN, NRCI, and CFRA scalars

Accordingly, SCE maintains a risk-neutral framework because the probability distribution of wildfire outcomes remains unchanged, and the scalars operate solely to adjust consequence valuation rather than altering probabilistic weighting.

i. SCE applies the following scalars to monetized safety consequences:
Access and Functional Needs (AFN) scalar
Non-Residential Critical Infrastructure (NRCI) scalar
Community Fire Risk Assessment (CFRA) scalar

These scalars are applied as multiplicative adjustments to monetized safety consequences after baseline consequence values are calculated

b. SCE characterizes its BCR calculations as "risk-neutral" because the framework preserves the expected-value formulation of risk and does not apply any non-linear risk-aversion function to the probability–consequence distribution. While AFN, NRCI, and CFRA scalars adjust the monetized value of safety consequences, they do not modify the underlying probability distribution or the weighting of extreme outcomes.

ii. As described in response to part a, SCE distinguishes between (1) a risk function, which alters the probability-weighted treatment of outcomes across the full distribution, and (2) a risk scalar, which adjusts the valuation of consequences for specific populations or geographies without affecting probability structure.
iii. As described in response to part a, SCE considers the application of risk scalars to be consistent with a "risk-neutral view" because the scalars operate only on consequence valuation and do not alter the probability distribution or introduce any preference for tail events. Accordingly, the expected-value structure of the risk calculation remains unchanged, consistent with Commission guidance.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 4

To: SPD
Prepared by: Bryan Landry
Job Title: Senior Advisor, Enterprise Risk Management
Received Date: 6/4/2026

Response Date: 6/19/2026

Question 14.a-b:
SCE refers to "qualitative components of its former IWMS risk framework," (p. 43) referring to its Integrated Wildfire Mitigation Strategy (p. 16). Describe how the qualitative components of SCE's IWMS risk framework are incorporated into SCE's current grid-hardening decision-making framework. In your description:

a. Describe how the qualitative components from IWMS affect risk modeling (i.e., WIM) and mitigation selection.

b. Explain whether these qualitative components can override or modify the outcome of the quantitative BCR analysis (e.g., would they interrupt the flow shown in Figure III-6 "BCR-Based Decision-Making Flow Chart" on p. 42).

i. Could the incorporation of these qualitative components result in a circuit with a BCR below 1.0 advancing?

ii. Could it result in SCE substituting one hardening option for another?

Response to Question 14.a-b:

a. As directed by RDF Phase III and Phase IV decisions, and as described in SCE's Wildfire and PSPS Assumptions workpaper, monetized risk scores are calculated based on the full distribution of natural unit consequences (e.g., buildings destroyed, buildings damaged, acres burned) from the WIM model, which are then converted to monetized values.

   As described in Chapter 4 (Wildfire and PSPS), pp. 34–35, certain qualitative components from SCE's former Integrated Wildfire Mitigation Strategy (IWMS) are incorporated as scalars to account for location-specific factors, such as social vulnerability (e.g., AFN/NRCI) and egress (e.g., CFRA).

   The resulting monetized risk values are then used in conjunction with mitigation costs and effectiveness to derive benefit-cost ratios (BCRs) for each proposed mitigation. These BCRs inform mitigation selection, as described in Figure III-6 ("BCR-Based Decision-Making Flow Chart") on page 42.

b. No.
   i. Yes. The addition of these scalars could result in marginal BCRs exceeding 1.0 in

areas where social vulnerability or egress-related factors are present.

ii. Yes. However, it is unlikely that these scalars alone would result in SCE substituting one hardening option for another, as they are applied upstream to BCR calculations across all mitigation options prior to embarking on final selection and prioritization.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 4

To: SPD
Prepared by: Angelo Rivera
Job Title: Sr. Advisor
Received Date: 6/4/2026

Response Date: 6/24/2026

Question 38:
Given SCE's use of circuit-level rather than segment-level RRUs, explain how SCE targets high-risk segments for hardening on circuits that include relatively low-risk segments.

Response to Question 38:

SCE's historical hardening strategy was executed at the circuit-segment level and informed by earlier, evolving consequence models. While appropriate during earlier stages of system hardening, this level of granularity has become increasingly suboptimal as the program has matured. The segment-level approach has left many circuits with non-contiguous, partially hardened segments, creating artificial stop-and-start points for mitigation activities and embedding execution inefficiencies into the remaining scope.

Segment-level hardening was a reasonable risk-reduction strategy when a large portion of SCE's overhead system remained unhardened and incremental risk reductions were higher than current estimates. However, practical execution constraints and the evolution of hardening strategies have materially reduced the marginal risk reduction achievable through continued application of this approach.

Shifting to a circuit-level RRU provides a more decision-relevant framework by evaluating whether the remaining unhardened portions of a circuit should be addressed in aggregate, rather than in isolation. This approach also enables identification of opportunities where existing hardened segments can be supplemented with additional circuit-wide risk reduction, such as through REFCL, which can help protect the entire circuit. Evaluating hardening needs at the circuit level supports progression toward fully hardened circuits, which in turn contributes to raising PSPS wind thresholds, resulting in reduced reliance on PSPS, and improved PSPS effectiveness.

SCE targets high-risk segments within circuit-level RRUs through a risk-driven, marginal evaluation framework, despite using circuit-level units for planning and investment decisions. At the portfolio level, many of SCE's highest-risk segments were previously prioritized and hardened under earlier segment-level approaches. Alternative 2 confirms this. The analysis in Alternative 2 demonstrates that certain circuits continue to exhibit elevated residual risk relative to the broader system, even after covered conductor (CC) installation, indicating the presence of remaining high-risk segments.

Within partially hardened circuits, remaining high-risk segments are evaluated in aggregate at the circuit (RRU) level. Where these segments are material in size and risk contribution, they elevate the circuit's overall risk profile and are therefore captured for additional hardening through the BCR framework.

Where circuits include a mix of high- and low-risk segments but are not selected for further hardening, this indicates that:

- The remaining high-risk exposure is limited in scale, and/or
- The incremental risk reduction is insufficient to support a cost-effective BCR relative to other candidate RRUs.

Additionally, SCE has established CC as the standard within HFRA. Any remaining unhardened segments that do not meet current BCR thresholds are addressed through asset lifecycle activities, such as replacement or repair, ensuring continued risk reduction over time.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET P u b A d v - S C E - 2 0 2 6 - R A M P - A Y N 0 2

To: Public Advocates Office
Prepared by: Daniel Komula
Job Title: Senior Advisor
Received Date: 7/30/2026

Response Date: 8/7/2026

Question 02.a-n:
Please provide a detailed breakdown for all mitigation lifecycle costs (not just installation and operations and maintenance lifecycle costs) of SCE's proposed Wildfire Covered Conductor Program (WCCP) and Targeted Undergrounding (TUG). This should include, but not be limited to, a breakdown and explanation for all costs recovered from ratepayers:

a. Capital costs.
b. Maintenance costs.
c. Operation costs.
d. Expense costs.
e. Engineering costs.
f. Permitting costs.
g. Depreciation costs.
h. Negative salvage value and negative salvage value depreciation costs.
i. Rate of return and debt costs to ratepayers.
j. Asset retirement costs.
k. Asset removal and asset disposal costs at end of useful.
l. Property and income taxes.
m. Other costs recovered from ratepayers.
n. Other costs not included above.

Response to Question 02.a-n:

SCE objects to this request to the extent it seeks analyses, calculations, studies, forecasts, or compilations that do not exist and would require SCE to create new analyses for purposes of responding to this data request. SCE further objects to this request to the extent it seeks information beyond the scope of this Risk Assessment and Mitigation Phase ("RAMP") proceeding and the requirements established by the Commission's Risk-Based Decision-Making Framework ("RDF"). The scoping memo in this proceeding, issued on August 6, 2026, reflects that the issue of mitigation lifecycle costs is not in scope for this proceeding.

Subject to and without waiving these objections, SCE responds as follows:

SCE has not performed the comprehensive lifecycle cost analysis requested for the Wildfire Covered Conductor Program ("WCCP") or Targeted Undergrounding ("TUG") and therefore does not possess a document, study, testimony exhibit, workpaper, or analysis that separately quantifies each of the cost categories identified in subparts (a) through (n).

For purposes of the 2026 RAMP, SCE evaluated WCCP and TUG consistent with the Commission's RDF and RAMP requirements. The RAMP process evaluates mitigation alternatives using cost, risk reduction, and benefit information necessary to support risk-informed decision making. The RAMP framework does not require utilities to separately calculate, forecast, or present the full lifecycle revenue requirement impacts associated with proposed mitigations, including detailed breakdowns of capital costs, maintenance costs, operations costs, depreciation, cost of capital, taxes, negative salvage, asset retirement obligations, end-of-life disposal costs, or other ratemaking elements requested here.

Accordingly, SCE has not prepared the detailed lifecycle cost breakdown requested and is unable to provide the requested analyses because they do not currently exist. No responsive documents have been identified that separately quantify each of the requested cost categories for WCCP and TUG as part of the 2026 RAMP application. However, SCE did provide details on the ongoing O&M expenses used for the Benefit Cost Ratio (BCR) calculations for Covered Conductor and Targeted Undergrounding.[1]

This request effectively seeks a new cost-of-service and ratemaking analysis rather than information required for evaluating SCE's 2026 RAMP application based on applicable Commission requirements.

[1] See Chapter 4 Workpaper - Wildfire and PSPS BCR Methodology for Covered Conductor and Targeted Undergrounding.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET P u b A d v - S C E - 2 0 2 6 - R A M P - A Y N 0 1

To: Public Advocates Office
Prepared by: Daniel Komula
Job Title: Sr Advisor
Received Date: 7/3/2026

Response Date: 7/16/2026

Question 06.a-b:
Please respond to the following regarding the disconnection, grounding, or removal of idle facilities:

a. Please explain whether SCE has budgeted or forecasted costs in this RAMP or the anticipated General Rate Case (GRC) cycle for the disconnection, grounding, or removal of idle facilities in HFRA. If so, please provide a detailed breakdown of the costs. If not, please explain when SCE expects to do so.
b. To the extent SCE's response to Question 6.a. does not separately identify costs specific to idle transmission facilities, please explain whether SCE has budgeted or forecasted costs specifically for the disconnection, grounding, or removal of idle transmission facilities. If so, please provide a detailed breakdown of the costs. If not, please explain when SCE expects to do so.
c. Please explain and provide details on whether SCE has budgeted or forecasted costs specifically for the disconnection, grounding, or removal of idle transmission facilities that are recovered from ratepayers outside of the GRC, for example through Federal Energy Regulatory Commission (FERC) Accounts.

Response to Question 06.a-b:

a) *Please explain whether SCE has budgeted or forecasted costs in this RAMP or the anticipated General Rate Case (GRC) cycle for the disconnection, grounding, or removal of idle facilities in HFRA. If so, please provide a detailed breakdown of the costs. If not, please explain when SCE expects to do so.*
   - SCE has not specifically budgeted or forecasted costs in RAMP or the upcoming GRC for disconnecting, grounding, or removing idle transmission lines in HFRA. SCE may include some of these costs in the upcoming 2029 GRC but SCE does not know when the costs will be finalized. They may not be finalized until shortly before SCE files the 2029 GRC.

b) *To the extent SCE's response to Question 6.a. does not separately identify costs specific to idle transmission facilities, please explain whether SCE has budgeted or forecasted costs specifically for the disconnection, grounding, or removal of idle transmission facilities. If so, please provide a detailed breakdown of the costs. If not, please explain when SCE expects to do so.*
   - SCE estimates costs for grounding work of approximately $6,900 per ground based on SCE's experience on completed grounding installations. SCE estimates costs for

circuit removal (conductor only) of approximately $292,000 per circuit mile based on SCE's planned removals that are currently in the execution/design phase.

c) *Please explain and provide details on whether SCE has budgeted or forecasted costs specifically for the disconnection, grounding, or removal of idle transmission facilities that are recovered from ratepayers outside of the GRC, for example through Federal Energy Regulatory Commission (FERC) Accounts.*

- SCE has not specifically budgeted or forecasted costs for disconnecting, grounding, or removing idle transmission lines from ratepayers outside of the GRC. Capital costs associated with idle transmission lines are generally not allocated to FERC-jurisdictional customers because the lines are not under the control of CAISO. Associated O&M expense is allocated to FERC-jurisdictional customers pursuant to the allocators in SCE's FERC Formula Rate.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 5

To: SPD
Prepared by: Alysha Sanchez
Job Title: Sr. Advisor
Received Date: 6/5/2026

Response Date: 6/19/2026

Question 30:
How did SCE determine the balance between high-cost proactive hardening investments and lower-cost operational mitigations, particularly where individual program BCRs appear low?

Response to Question 30:
SCE determined the balance between proactive hardening and operational mitigations based on overall risk reduction (LoRE × CoRE) rather than individual program BCRs. Proactive investments were prioritized to reduce underlying failure drivers and deliver sustained risk reduction, while operational and maintenance programs were designed to reflect compliance obligations.

As a result, higher BCR investments are used to target the highest concentrations of risk within the system, while lower BCR programs can still be required to meet existing CPUC or other regulatory or legal requirements.

The Commission additionally recognizes that BCRs are only one of many factors that could influence mitigation selection and prioritization.[1]

[1] See, e.g., RDF, Appendix A, Row 26. "The utility's proposed Enterprise Portfolio, including its Mitigation and Control Programs selection, Risk Reporting Unit prioritization, and Risk Mitigation Portfolio optimization can be influenced [emphasis added] by Benefit-Cost Ratios and other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis."

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 5

To: SPD
Prepared by: Matthew Muto
Job Title: Consulting Engineer
Received Date: 6/5/2026

Response Date: 6/19/2026

Question 70.a-c:
Per Table VI-10 "Proposed Plan, Control Program Estimated Costs and Benefit Cost Ratios for 2029-2032" (p. 47), the majority of SCE's proposed control programs have BCRs not just below 1, but close to zero.

a. Why pursue these programs?

b. If these programs are required for regulatory compliance, then specify which agencies or bodies require these programs for compliance

c. List the ways SCE's BCR methodology might skew the BCRs downward for its hydro asset failure risk mitigation programs.

Response to Question 70.a-c:

a. As described in the RAMP Hydro Asset Failure chapter, controls and programs with BCRs below one (1) are required for reasons of regulatory compliance.
b. SCE dams are regulated by the Federal Energy Regulatory Commission (FERC) Division of Dam Safety and Inspections and/or the California Department of Water Resources Division of Safety of Dams (DSOD). See 2026 RAMP Hydro Asset Failure discussion in Chapter 13 (p. 2, pp. 4-5, and pp. 7-14).
c. SCE is mandated to use the expected value for evaluation of risk reduction benefits in calculating BCR. This skews BCRs lower downward for low likelihood-high consequence events such as dam failure.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 5

To: SPD
Prepared by: Matthew Muto
Job Title: Consulting Engineer
Received Date: 6/5/2026

Response Date: 6/19/2026

Question 85.a:
Because each dam is unique and discretely tranched, explain how SCE tranches (or ranks) the dams using the likelihood of seismic, flood and operational failure probabilities based on the construction, location and operational risks associated with each dam.

a. If SCE did not use likelihood of seismic, flood and operational failure probabilities based on the construction, location and operational risks associated with each dam to tranche or rank them, then why not?

Response to Question 85.a:
As stated in Chapter 13, page 22, Section II.F Tranches:

> "While it is possible to group two or more dams in a single quintile using the recommended Quintile Approach, the dams themselves do not share homogenous risk profiles. Each dam differs greatly in location, size, height, and construction material. Therefore, the mitigations and controls for individual dams that are within the same tranche, will likely be unique to the individual dams. As each dam is evaluated, controls and mitigations are proposed and implemented that are tailored to address specific conditions unique to each dam."

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 7

To: SPD
Prepared by: Matthew Muto
Job Title: Consulting Engineer
Received Date: 6/11/2026

Response Date: 6/17/2026

Question 04.a-b:
4. Why does SCE propose a plan with a lower BCR than either alternative?
   a. Are there regulatory obstacles to the alternative plans?
      i. If so, describe them.
   b. Are there other issues blocking the alternatives?
      i. If so, describe them.

Response to Question 04.a-b:

Consistent with the Commission's guidance (RDF, Appendix A, Row 26), the Benefit-Cost Ratio (BCR) was one of many factors SCE considered in developing its proposed and alternative portfolios.

SCE is required to use expected-value methodology for evaluation of risk reduction benefits, which produces lower BCRs for low-likelihood, high-consequence events such as dam failure. As a result, all three plans (proposed and both alternative plans) yield BCRs below 1.0 The marginal differences among them do not, on their own, support selection of an alternative over the Proposed Plan. The Chapter 13 narrative (pp. 44-49, p. 52, pp. 55-56) discusses the factors leading to the selection of the Proposed Plan.

a. Alternative Plan #1 does not face direct regulatory obstacles; However, the expanded scope of capital work it contemplates is not currently required by regulators, and regulatory priorities may not align with the additional projects included in that alternative. The primary mitigations distinguishing Alternative Plan #2 from the Proposed Plan— expanded use of dam decommissioning (M1) and the addition of dam divestiture (M4)—are subject to significant regulatory scrutiny. Dam removal is a complex, protracted, and expensive undertaking requiring detailed engineering plans, regulatory permits, environmental review, and stakeholder consultation across multiple agencies. Dam divestiture requires FERC approval of a license transfer, and FERC is unlikely to allow a licensee to transfer the license of a project without first remediating identified deficiencies or issues. Both actions would also be subject to CPUC review and approval.

b. For Alternative Plan #2, divestiture is contingent on the availability of willing, qualified

buyers. The pool of potential owners capable of assuming the operational complexity and regulatory obligations associated with high- and significant-hazard dams is limited, which introduces market uncertainty that is outside SCE's control. These mitigations are nonetheless realistic, as evidenced by SCE's recent divestitures of smaller hydroelectric projects such as Lytle Creek and Fontana. Nonetheless, this option may be pursued at a later date if future projections of life-cycle costs for individual projects support such action.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET S P D - S C E - 2 0 2 6 R A M P - 0 0 9

To: SPD
Prepared by: Matthew Muto
Job Title: Engineer
Received Date: 6/18/2026

Response Date: 6/30/2026

Question 02.a:
In the Chapter 13 work paper "Data Tables – Hydro" (Excel spreadsheet), SPD does not see the data on benefits and costs for the two alternative plans. SPD needs to be able to reproduce SCE's BCRs for its alternative plans.

a. Are the calculations of these benefits available elsewhere in SCE's RAMP application or work papers?
   i. If so, where?
   ii. If not, provide them.

Response to Question 02.a:

SCE notes that it is aware that is required to provide the alternative plan data in the data tables format for any risk. SCE was required to provide two alternatives at the RRU level for wildfire risk only.

From D.25-08-032 p. 121:

> *"For the data template submitted with SCE's 2026 RAMP and its subsequent GRC application, the Commission requires that SCE present, at minimum, two alternative mitigations for each proposed RRU that reduces Wildfire and/or PSPS risk."*

SCE is not aware of any requirement to provide the information requested in the data tables for the alternative ***plans*** for any risk, including Wildfire. SCE has provided the excel model files for the alternative plans that can be used to calculate BCRs for Hydro Asset Failure. These can be accessed at www.sce.com/applications under the 2026 RAMP folder.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company Regarding 20226 Risk Assessment Mitigation Phase. (U 338-E)	Application No. 26-05-018 (Filed May 15, 2026)

MUSSEY GRADE ROAD ALLIANCE INFORMAL 2026 SCE RAMP COMMENTS

Joseph W. Mitchell, Ph.D.
M-bar Technologies and Consulting, LLC
19412 Kimball Valley Rd.
Ramona, CA 92065
Telephone: 858 228 0089
Email: jwmitchell@mbartek.com

On behalf of
Diane Conklin, Spokesperson
Mussey Grade Road Alliance
P.O. Box 683
Ramona, CA 92065
Telephone: (760) 787-0794
Email: dj0conklin@earthlink.net

Dated: September 3, 2026

1. INTRODUCTION

Southern California Edison (SCE) released its RAMP on May 15, 2026.[1] The Scoping Memo, issued on August 6, 2026, allows parties to serve Informal Comments on SPD and the service list by September 4, 2026. Accordingly these informal comments are being provided to SPD to facilitate the development of their SCE 2026 RAMP report.

SPD has supplemented SCE's filing with an extensive series of data requests in areas that SCE has made major changes in since its last GRC filing. Indeed, during its previous GRC cycle SCE was informed that its IWMS risk framework was not adequate because it did not have a probability component and could not be considered a full risk analysis. SCE has since developed a probability-based framework for its risk analysis and introduced a methodology for estimating tail risk that is more highly sophisticated than its predecessors at the other major IOUs. MGRA addresses this new methodology among other topics.

These comments have been prepared by MGRA's expert witness Joseph W. Mitchell, Ph.D.

2. ISSUES

2.1. Risk Models

2.1.1. Power Law Model

SCE has developed a new approach to estimation of wildfire sizes and consequences that simulates wildfire events using physics-based models. The results of this model show power-law behavior and produce a natural truncation point. As required by D.24-05-064, SCE supports its methodology with a whitepaper, included as Workpaper 1 of its RAMP filing.[2] This whitepaper was served on the R.20-07-020 service list prior to its first pre-RAMP workshop, and as a result has been subject to a number of SPD data requests prior to the issuance of the RAMP filing. SCE's approach "*presents a method of truncation that is designed to appropriately reflect a broader range*

[1] A.26-05-018; APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) REGARDING 2026 RISK ASSESSMENT MITIGATION PHASE; May 15, 2026. (RAMP)
[2] A.26-05-018; 2026 RAMP; Chapter 4; Wildfire and PSPS; SCE 2026 RAMP Power Law Whitepaper.

of potential future outcomes, including tail risk events which may not be fully reflected by historical wildfire events."[3] D.24-05-064 states that "*utility use of truncated power law distribution, by conducting multiple tests of truncation values to determine goodness of fit to existing data, will improve modeling of wildfire tail risk and help ensure that risk estimation is capped at a level reflecting historical data*."[4] SCE notes that "*capping risk metrics based on historical events may not fully capture the probabilities and/or consequences of future events*."[5]

SCE states a valid concern. The original power law approach approved by the Commission was a model developed by PG&E that capped maximum losses at 5 times those experienced during the Camp fire, based on PG&E's sensitivity analysis.[6] MGRA published a tail risk whitepaper that the Commission drew on to reach its determination.[7] Regarding the truncation point of power law distributions, it states that:

"*The first item that should be considered with regard to selecting an appropriate cap for the power law distribution is whether such a cap actually exists. The statistics in this region, corresponding to the very largest wildfires, are extremely limited. It is possible that larger fires are possible and that we simply haven't seen them yet. Such a hypothesis would be supported by the fact that the record for the largest wildfire in California has been broken every few years over the past two decades. So, the possibility of larger future fires cannot be discounted.*

However, there is theoretical support justifying a maximum fire size. A physical limit will be reached as the wildfire size approaches that of the largest contiguous burnable spaces which are bounded by the sea and non-vegetated areas, and fire-resistant developed areas. This effect is captured in Moritz et. al."[8]

In the whitepaper, MGRA recommends increasing the run time for Technosylva wildfire simulations to 24 hours to capture larger losses. However, SCE's Whitepaper finds that even 24 hour simulations are not adequate to capture tail-risk events.[9]

---

[3] Id.; p. 1.
[4] D.24-05-064; Finding of Fact 19.
[5] Op. Cite; p. WP-4.
[6] Op. Cite; pp. 51-52.
[7] R.20-07-020; TAIL RISK AND EVENT STATISTICS FOR UTILITY PLANNING; August 1, 2023; p. 21.
[8] Moritz, M.A., et al., 2005. Wildfires, complexity, and highly optimized tolerance. Proceedings of the National Academy of Sciences 102, 17912–17917. https://doi.org/10.1073/pnas.0508985102
[9] Power Law Whitepaper; p. 31.

Instead, SCE has developed a model that incorporates the Moody's RMS 2.0 risk model, which provides millions of stochastic simulations of wildfires including those leading to catastrophic losses, and is not limited by historical data. This RMS model captures tail risk much better than previous Technosylva-based simulations. However, SCE's Technosylva-based FireSight 8 is still necessary to predict the consequences of ignitions at the asset level, so the SCE model scales consequences predicted by FireSight 8 using RMS 2.0 simulations from the same general geographic area.

A technical description of Moody's RMS 2.0 wildfire model can be found at the California Department of Insurance website.[10] The document "*provides an overview of the Moody's RMS U.S. Wildfire HD Model built using the latest geospatial, and climatological data to simulate hazards from direct flame, radiant heat hazard, ember accumulations, potential urban conflagrations, and damageable smoke across 100,000 years of synthetic wildfire events*."[11]

Among the features of the Moody's model that provide a more complete set of extreme events are:[12]

- Historical and stochastic weather for the wildfire simulations. The primary source of weather data used for wildfire model simulations is the NLDAS dataset (Xia et al., 2012), which included hourly temperature, precipitation, specific humidity, solar radiation, and U- and V- winds at 1/8th degree weather cell resolution.
- The fire weather content used in the model is daily ERC-G, Fuel Moisture (computed using Nelson and GSI methodologies), wind speed and wind direction.
- The LANDFIRE data layers, available at 30m resolution for the entire modeled domain, also incorporate in its fuel layers the impacts of large-scale vegetation management efforts (till 2024) to mitigate wildfire risk.

---

[10] Moody's; Moody's Required Model Information. (RMS 2.0)
https://www.insurance.ca.gov/01-consumers/180-climate-change/upload/Moodys_RMS_Required_Model_Information.pdf
Downloaded August 11, 2026.
[11] RMS 2.0; p. 2.
[12] Id.; pp. 8-13.

- The model considered ignitions and burn area for historical wildfires that were larger than 100 acres for model development, calibration, and validation.
- Weather model with 1/8th degree resolution from NLDAS-2 leveraging weather data from local and RAWS weather stations.
- Climate change corrections using fuel dryness to reflect present day wildfire risk.
- Stochastic weather simulations using dryness, ENSO, wind speeds, including katabatic (Santa Ana) winds.
- Stochastic wildfire ignitions, including those from power lines.
- Stochastic hazard footprints including radiant heat, flames, embers, and smoke.
- Corrections for fire suppression.
- Modeling of structure-to-structure spread and urban conflagration.
- Smoke hazard databased on wind transport models.
- Incorporation of structure type to determine home vulnerability.

While some California wildfires were used for calibration and training of the RMS 2.0 model, it generally shows a good correlation between predicted and measured losses, as shown in the figure below:

Figure 21. Comparison of California trended industry losses to modeled losses

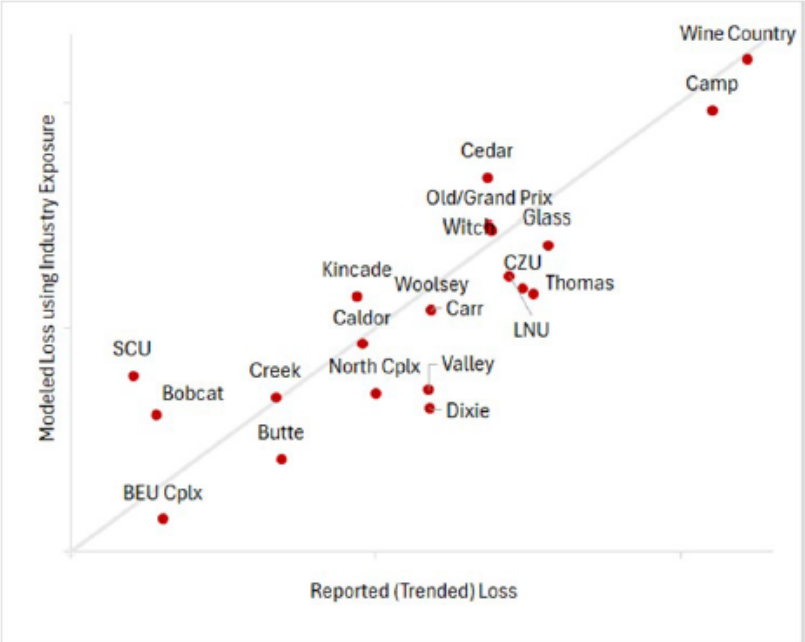


Figure 1 - RMS 2.0 predicted versus measured losses for major California wildfires[13]

The SCE Whitepaper itself is backed by an extensive bibliography, including key papers on wildfire, power laws, extreme event statistics. Its methodology was purportedly derived from Taleb, a thought-leader in regard to the challenges faced by models with poor statistics under fat-tailed distributions, although it is difficult to see the exact match between the cited reference in Taleb and the formulae presented in the whitepaper.[14] Its approach of scaling consequences determined by Technosylva models by tail-risk factors using RMS 2.0 appears plausible. SCE plots the results of its model and it seems to reproduce the upper end of historical losses in the SCE service area very well, as shown in the following figures.

For the largest wildfires, acres burned appears to be represented equally well between the WIM model and a "pure" power law:

---

[13] Id.; p. 41.

[14] Taleb, N.N., 2020. Statistical Consequences of Fat Tails: Real World Preasymptotics, Epistemology, and Applications. STEM Academic Press.
As per SCE DRR MGRA-SCE-Verbal-001-03,
Taleb pp. pp. 99 106, 111 121, 132 144, 175 184.

Figure V-13
System-level Distribution of Wildfire Integrated Model (WIM) Power-law fit (log-log plot) at Expected Value (Acres Burned)

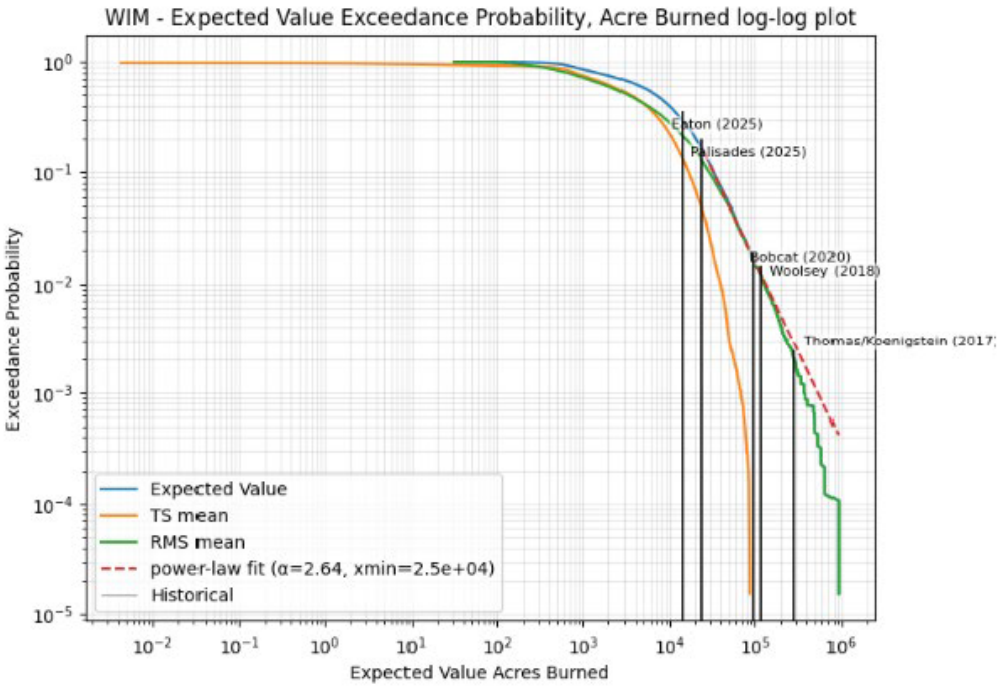


Figure 2 - WIM Exceedance curve in Acres, vs power law, Technosylva, and historical.[15]

[15] Power Law Whitepaper; p. WP-46.

Figure V-14
System-level Distribution of Wildfire Integrated Model (WIM) Power-law fit (log-log plot) at Expected Value (Buildings Destroyed)

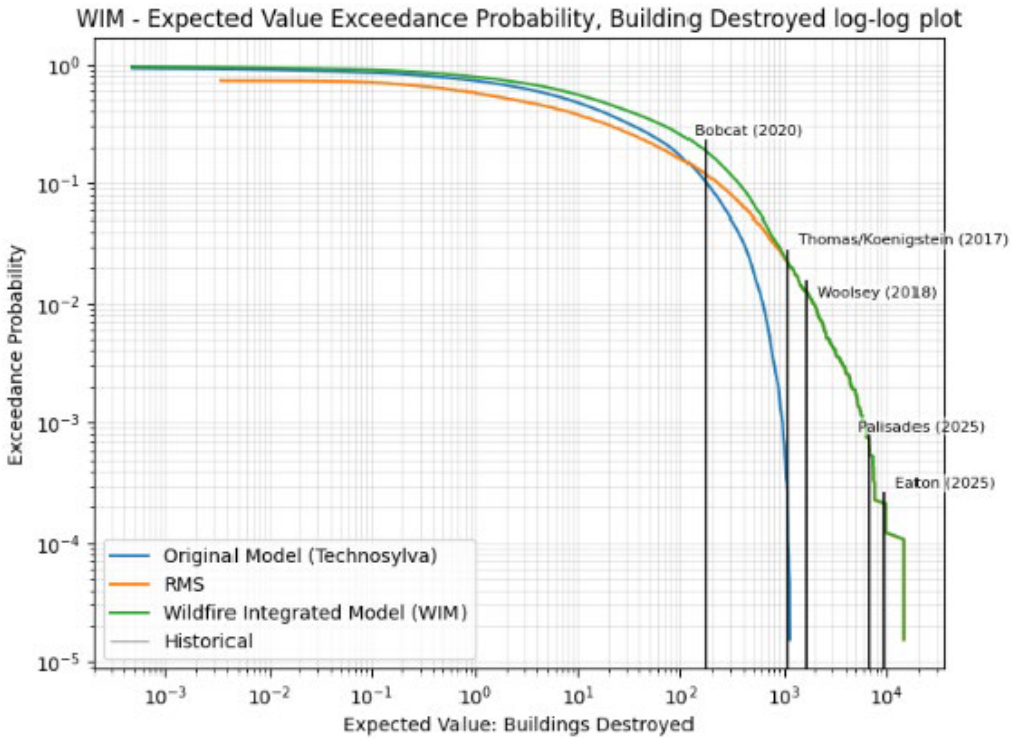


Figure 3 - WIM Exceedance curve in Buildings Destroyed, Technosylva, and historical.[16]

As can be seen, WIM is good at reproducing losses (financial and acres burned) from large and destructive historical wildfires. During a meet and confer, SCE was asked to whether the historical wildfires on the plots (Bobcat, Thomas/Koenigstein, Wolsey, Palisades, Eaton) were used to affect the fit. SCE claims that the WIM model curve was totally independent of these historical wildfires, making the quality of fit in the tail region remarkable.[17]

Additionally, the original Technosylva model can be seen to severely underpredict losses. The amount by which it does so is particularly surprising because the simulations shown in the figure were 24 hour duration. Only a few years ago, it was the position of SCE and other utilities

[16] Power Law Whitepaper; p. WP-47.
[17] SCE DRR MGRA-SCE-Verbal-001-01.

that 24 hour simulations were too extreme and would overpredict losses.[18] As MGRA notes about size limitations due to developed areas, well before the 2025 LA wildfires: "*The figure above demonstrates that fire size growth is limited by the physical boundaries, but losses may increase as wildfire encroaches into neighborhoods*."[19]

In the Acres Burned plot, we see truncation appear for wildfires larger than 200,000 acres, as the IWM model predicts smaller wildfires than a power law would. In the building loss plot, it would be interesting to see a power law fit to the curve of the losses, and the exponent compared to that of the acres burned. In this case as well, the largest losses (Eaton and Palisades) seem to be deviating on the low side as the curve bends more steeply than a log-log fit would accommodate. This would appear to support the supposition that the most destructive historical California wildfires are less frequent than would be expected by extrapolation of a power law. In other words, truncation seems to be in effect at the landscape scale in extreme California wildfires, and the SCE WIM model is determining its cutoff point with a physics-based model.

Overall, the SCE model appears to be more robust than other power law approaches to date, and to better account for extreme losses. The PG&E truncation point was chosen from a mathematical fit, which Taleb warns is inappropriate because it is extrapolating with a function that has undefined higher moments.[20] MGRA was supportive because 1) based on SCE 8 hour versus 24 hour simulations, it was clear that the largest fires often "burn everything" and are limited by geography, and 2) The factor of 5 above the Camp fire offered considerable headroom for tail-risk events even larger than those historically observed, 3) the sensitivity analysis showed that it was compatible with the existing data. SCE's model, on the other hand, is based on the physics, climatology, landscape, and built environment and therefore more realistically depicts worst-case scenarios, and the truncation point emerges naturally and is not imposed on the fit. SCE's model does not make assumptions about the behavior of the power law distribution once it extends outside the historical range.

[18] R.20-07-013; MGRA Tail Risk Whitepaper; TAIL RISK AND EVENT STATISTICS FOR UTILITY PLANNING; August 1, 2023; pp. 32-37.
[19] Id; p. 36.
[20] Taleb; pp. 34-35.

In conclusion, at this point in the review SCE seems to have the most advanced model compared to the other major utilities. It does not use a truncated power law to generate a distribution, but rather it uses a physics based model and the distributions that result from the model match the characteristics of a truncated power law. Pending further validation and external review, it may be appropriate to update the best practice guidelines to highlight the SCE methodology.

2.1.2. Probability of Ignition

2.1.2.1. Appropriate wind sensitivity to ignition

SCE continues to use machine learning models as part of its likelihood of ignition calculation.[21] MGRA filings in previous GRC cycles and WMPs have demonstrated that machine learning models lack the ability to accurately capture the time-dependency of weather-initiated failures that result in ignitions. However, MGRA's analysis of SCE's 2026-2028 WMP found that some of SCE's machine learning variables that corresponded to integrated stress over time (specifically Log_Windforce, max_wind_magnitude, and max_of_sum_of_seg_downforce) were shown to be significant in predicting ignitions.[22] However, these predictions are also based on FIPA ignitions, which will be shown in Section 2.1.3 to be less than ideal for predicting the where catastrophic wildfires are likely to occur.

In response to Data Request SPD-SCE-2026RAMP-004-44a, SCE provided probability of ignition geodatabase data for segments, circuits, and FLOCs. MGRA analysis in its comments will examine the following to determine whether this probability of ignition is related to the potential for extreme wind, by

- Examining the maximum wind speeds measured near the highest risk segments and
- Determining whether PSPS damage points are on or near circuits and segments with the highest probability of ignition.

[21] RAMP; Chapter 4; p. 33.
[22] OEIS Docket 2026-2028-WMPs-Base; MGRA Comments on SCE 2026-2028 WMP; pp 16-17. https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58804&shareable=true (MGRA 2026-2028 SCE WMP Comments)

2.1.3. Use of FIPA events to determine Probability of Ignition

SCE uses data from its Fire Investigation Preliminary Analysis (FIPA) to populate the set of ignition events that it uses for predictive ignition modeling. Data is analyzed between 2019 and 2024.[23] As SCE explains:

"*SCE uses FIPA ignitions to calibrate the POI model because FIPA is the more complete and granular dataset for estimating ignition likelihood by asset and ignition sub-driver. CPUC-reportable ignitions are important for regulatory reporting and trend monitoring, but they represent a subset of ignition events that meet defined reporting thresholds and therefore do not capture all ignition events relevant to modeling ignition likelihood*."[24]

While having a larger statistical sample is generally better, it is only helpful if the underlying drivers determining the characteristics of the large and small sample are similar in cause. Otherwise, overemphasis may be placed on ignition drivers that have not been associated with and are not likely to cause catastrophic wildfires. Also, all ignition samples suffer from known biases which limit the predictive value of the data set.

2.1.3.1. FIPA ignition drivers versus reported ignitions and catastrophic wildfires

SCE's FIPA events have drivers that are atypical of reported ignition events and ignition drivers for catastrophic wildfire.

In response to SPD's data request, SCE provides the following table that reports drivers in the "other" category, which SPD observes "*is by far the most prevalent kind of FIPA ignition*":[25]

[23] RAMP; Chapter 4; p. 23.
[24] SCE DRR SPD-SCE-2026 RAMP-010; Q. 10.
[25] SCE DRR SPD-SCE-2026 RAMP-010; Q. 15.

Sub-driver Specifics	2019	2020	2021	2022	2023	2024
Bird Nest	0	2	2	15	46	33
Foreign Object	1	1	1	3	0	2
Inconclusive	1	2	1	1	0	3
Lightning	0	0	0	1	0	4
Vegetation	0	0	0	0	0	1
Total	**2**	**5**	**4**	**20**	**46**	**43**

Table 1 – Breakdown of sub-drivers in D1c-Other for years 2019 to 2024 from SCE DRR SPD-SCE-2026 RAMP-010; Q. 15.

This DR was a follow up to SPD-SCE-2026 RAMP-004, Q.2a, which provided an Excel spreadsheet containing a summary of all FIPA ignition causes. The top 3 ignition drivers listed in the data request response are:

Driver	**Percentage of ignitions 2019-2024**
Other contact from object	21.0%
Transformer	14.0%
Insulator and bushing damage or failure	13.5%
Subtotal	**48.5%**

Table 2 – Top three drivers contributing to FIPA ignitions. The next largest is conductor damage or failure at 6.3%.

As shown in Table 1, "Birds nests" make up 75% of the "Other contact from object" category. So as predicted by FIPA, the top three contributors to wildfire ignition should be birds' nests, transformers, and insulator bushing or failure, and these should make up nearly half of all ignitions.

The ultimate goal of the ignition model, however, is to predict the probability of a wildfire with a potential to be catastrophic. None of these drivers has to date contributed to a catastrophic wildfire in California. A statistical analysis of large utility wildfires was performed as part of the MGRA testimony in the 2025 SCE GRC.[26] The analysis first showed that reportable ignitions for SCE and SDG&E showed a predominance of ignition by "external agents" – balloons, vehicles, animals, whereas PG&E ignitions which were restricted to Red Flag Warning days were dominated by vegetation contact and equipment failure:

[26] A.23-05-018; Exh. MGRA-01-E2; pp. 38-39.

Ignition Driver	**Percentage**		
	SDG&E	SCE	PG&E (RFW)
Vehicle	17	7	
Balloon	17	13	
Veg Contact	15	11	59
Other Contact	8	6	4 (all external)
Animal	5	13	
Wire Contact	3	5	1
Vandalism	2	5	0
Equipment	33	42	33

Table 3 - Percentage of enterprise ignition risk represented by different risk drivers as per SCE and SDG&E's 2022 Wildfire Mitigation Plans.[27] PG&E's enterprise risk analysis[28] is limited to National Weather Service Red Flag Warning (RFW) days. All PG&E external agent contact (vehicle, balloon, animal, other) is listed under "Other Contact".

The testimony then calculates the probability that major utility wildfires from SCE and PG&E arise from the same statistical distribution of drivers.

"*To illustrate this point, I have analyzed major utility fires from SCE[29] (>100 acres) and PG&E (> 500 acres)[30] between 2015 and 2020, binning them into "Agent" and "Non-Agent" drivers. These were analyzed with a Pearson Chi-squared goodness of fit (with/without Yates correction) to compare them against the distribution that would be expected based on expected likelihoods for different drivers*.:[31]

[27] OEIS-Docket 2023-22025-WMPs; 2020-2022 WILDFIRE MITIGATION PLAN UPDATE; San Diego Gas & Electric Company; February 11, 2022; p. 46. (SDG&E 2022 WMP)
OEIS-Docket 2022-WMPs; Southern California Edison Company; 2022 WILDFIRE MITIGATION PLAN UPDATE; FEBRUARY 18, 2022. (SCE 2022 WMP)
[28] OEIS-Docket 2022-WMPs; PACIFIC GAS AND ELECTRIC COMPANY; 2022 Wildfire Mitigation Plan Update; February 25, 2022. (PG&E 2022 WMP)
[29] Mitchell, Joseph W (2023), "IAFSS_2023_JWMitchell_UtilityWildfires", Mendeley Data, V3, doi: 10.17632/8nds4cx88k.3
https://data.mendeley.com/datasets/8nds4cx88k/3 (Mitchell Mendeley data)
DATA/SCE Ignitions 2015-2020 - 001. c Amended_2015-2020 CPUC Reportable Ignitions - jwm 22.xlsx
[30] OEIS Docket 2022-WMPs; Pacific Gas and Electric Company 2022 Wildfire Mitigation Plan Response to Revision Notice, June 27, 2022; pp. 1-13.
TN11043_20220627T144350_PGE_30Day_Revision_Notice_Responses.pdf
[31] Note that in this case, PG&E data was not limited to Red Flag Warning days but instead represented unfiltered ignition probability.

Driver	Observed	Expected	Chi2	Yates
Non-Agent	31	24.09	1.98	1.71
Agent	4	10.91	4.38	5.03
Total	35	35	6	7
P - Chi2	0.01168126			
P - Yates	0.00943576			

Table 4 - Statistical analysis of combined SCE and PG&E ignition data binned into Agent (balloon, 3rd party, vehicle, and Non-Agent (vegetation, equipment) to improve statistical power. Probabilities were calculated with the Excel function CHISQ.DIST.RT, using 2 degrees of freedom.[32]

Likewise, the drivers for FIPA events are not associated with catastrophic wildfire risk. While transformer failure qualifies as an equipment failure, it is not accentuated during RFW warnings and no transformer failure in California has yet resulted in a catastrophic wildfire. The potential that one of these ignitions occurs at the wrong place at the wrong time should be acknowledged. However, the "wrong time" is usually under extreme wildfire weather warnings, at the least FCS is activated, and PSPS may be in place, preventing the initial ignition from occurring at these times. To summarize, FIPA driver distributions are not consistent with driver distributions from reportable ignitions, and neither is representative of drivers linked to historic catastrophic wildfire.

2.1.3.2. Potential observational bias

SPD's discovery requests also illuminate the possibility that SCE's FIPA ignition results are highly dependent on the observation process. Examination of Table 1 readily shows this. Only 5 "birds' nest" ignitions occurred between 2019 and 2021, while 94 occur between 2022 and 2024. It is impossible that this is a statistical fluctuation. Also, while SCE claims in its response that environmental changes occurred in the 2019-2024 period, it has provided no explanation of any environmental change that could lead to such an incongruity.

When asked to explain the large changes in categorization over time, SCE responded:

"*Accordingly, the increase in the number of events reported in these categories is largely due to improvements in event identification, documentation, and classification practices, rather than solely reflecting an increase in the occurrence of such events. While SCE believes these*

[32] Mitchell Mendeley data; Data/IgnitionRiskRankings_v2_2208.xlsx

process improvements contributed to the increase in reported event counts, SCE cannot determine with precision the extent to which the observed changes are attributable to improved classification practices versus changes in the underlying occurrence of events."[33] Regardless of the source, and whether SCE considers these changes an "improvement", these events are being used to train SCE's POI model and thereby determine risk, and thereby determine geographic location of and type of mitigation recommended. SCE's FIPA events do not have the internal consistency that allows them to be a reliable source of ignition risk data regarding where and how potential catastrophic wildfire ignitions might occur.

2.1.3.3. Geographic distribution

MGRA did a geospatial analysis of the FIPA events provided in DR Response file 26_SAFARI_SPD-SCE-2026RAMP-004 Question 26.xlsx and found that of the 2,323 FIPA events included, only 19 of them fall into SCE's HFRA. MGRA has requested clarification in its Data Request 4, still pending.

2.1.3.4. SDG&E Results

SDG&E's RAMP and GRC use a similar methodology to SCE, adding events that they classify as "Evidence of Heat" into the ignition set used to train their POI model. SDG&E's approach suffers from the same weakness as SCE's – the additional events added to the statistical sample do not come from the same underlying drivers as reportable ignition events. SDG&E's argument for its method are similar to SCE's:

"*SDG&E considers this approach to be more statistically robust and reflective of real-world conditions. Including all available ignition-related data, regardless of reporting thresholds enhances confidence in mitigation effectiveness estimates and ensures that decisions on long-term wildfire mitigation strategies are grounded in a thorough, data-driven evaluation of asset performance and ignition behavior under field conditions*."[34]

[33] SCE DRR MGRA-SCE-003-01.a-c.
[34] OEIS Docket 2026-2028-Base-WMPs; San Diego Gas and Electric Company; Wilfire Mitigation Base Plan R2; p. 117.

MGRA analysis compared SDG&E's "evidence of heat" events to reportable ignitions and, similar to the SCE case, found that the underlying ignition drivers were different:[35]

Overhead Distribution Ignition-Related Drivers	2024/2025 Subject Matter Expert Ignition-Related Reduction (%)	Total Number of CPUC Reportable Ignitions and Evidence of Heat Events [2019 - 2024]	Fraction CPUC+EoH	Unmitigated Fraction CPUC+EoH	Risk Driver Contribution CPUC + EoH	Total Number of CPUC Reportable Ignitions [2019 - 2024]	Fraction CPUC	Unmitigated Fraction CPUC	Risk Driver Contribution CPUC + EoH
Animal Contact	90%	20	2.2%	0.2%	0.4%	19	15.6%	1.6%	4.0%
Balloon Contact	90%	27	3.0%	0.3%	0.6%	9	7.4%	0.7%	1.9%
Vehicle Contact	80%	20	2.2%	0.4%	0.9%	10	8.2%	1.6%	4.2%
Vegetation Contact	90%	72	8.0%	0.8%	1.6%	11	9.0%	0.9%	2.3%
Other Contact*	50%	47	5.2%	2.6%	5.3%	4	3.3%	1.6%	4.2%
Conductor	90%	123	13.6%	1.4%	2.8%	10	8.2%	0.8%	2.1%
Equipment – Non-Conductor**	39%	412	45.7%	27.9%	56.2%	49	40.2%	24.5%	63.3%
Other All***	10%	151	16.7%	15.1%	30.4%	9	7.4%	6.6%	17.2%
Undetermined****	70%	10	1.1%	0.3%	0.7%	1	0.8%	0.2%	0.6%
Overhead to Underground Connection	75%	20	2.2%	0.6%	1.1%	0	0.0%	0.0%	0.0%
Total	**n/a**	**902**		**49.5%**	100.0%	**122**		**38.7%**	100.0%

Table 5 - OH distribution ignition related drivers and subject matter expert estimates for Combined Covered Conductor ignition reduction efficiency, obtained from SDG&E's tables 6-10 and 6-11. Four columns (3-6,7-10) show total events reported, fraction of events represented by that driver, and the unmitigated fraction for that driver. Columns 3-6 show SDG&E's total including "evidence of heat" events while columns 7-10 show CPUC reportable ignitions only. Green highlighting indicates drivers for which that driver makes up a significatly larger fraction of reportable ignitions than evidence of heat events, and red highlighting shows the opposite.[36]

As with SCE, "Other" categories dominate the excess events that are not associated with reportable ignitions. As in the SCE case, none of these "Other" event drivers has been responsible for catastrophic wildfire ignition in the SDG&E service area.

2.1.3.5. PSPS blindness

A consistent weakness in utility wildfire statistics is the fact that during the most dangerous wildfire weather the system is often de-energized, so that no ignition or outage data is collected within the affected areas. MGRA in past filings has recommended the inclusion of "PSPS Damage"

[35] OEIS Docket 2026-2028-Base-WMPs; MGRA ; MUSSEY GRADE ROAD ALLIANCE COMMENTS ON THE R1 REVISION OF THE 2026 TO 2028 UPDATE OF THE WILDFIRE MITIGATION PLANS OF SDG&E; August 4, 2025; p. 18.
[36] Workbook SDG&E_2026-2028_Base-WMP_SDGE Tables_R1-jwm.xlsx; Tab SDGE Table-6-10-11.

events (damage discovered during PSPS restoration patrols) in the risk events that are used to estimate the probability of ignition. For example, the following show SCE's PSPS damage events from the January 2025 weather events.

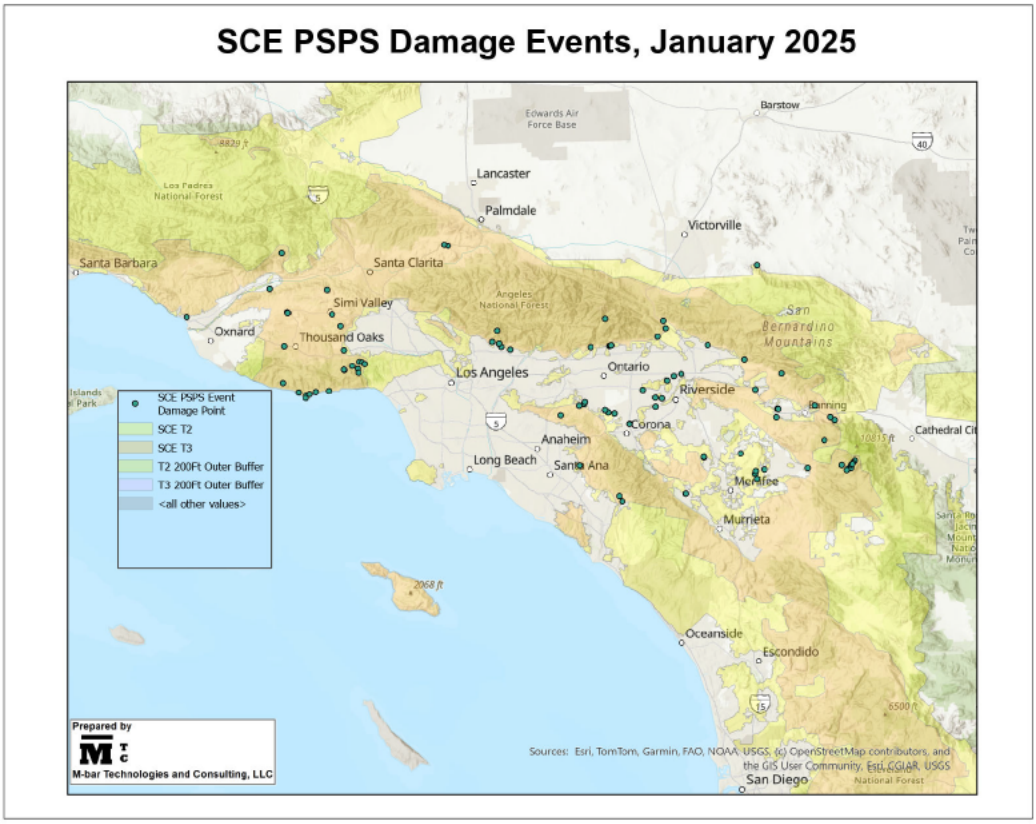


Figure 4 - SCE PSPS damage events provided to OEIS through quarterly reporting. This set shows the Q1 2025 data, mostly consisting of the January 2025 fire weather events. Damage points are indicated as dots, and SCE HFRA areas are shown.

The advantages of including PSPS damage events in the risk event sample used for estimating ignition likelihoods are that:

- These incidents occur in areas that can support high winds and fire weather.
- Many of these would have resulted in an ignition had power been on.
- The potential for catastrophic wildfire was significant, otherwise PSPS wouldn't have been activated.

While these events were in PSPS areas, and therefore not subject to ignition, one of the residual risks is that PSPS may not in all cases be optimized for the correct timing or geographic extent, meaning that an ignition might occur before or after a PSPS event or outside of its

geographic boundaries. An example of this is the Zogg fire, in which the PSPS boundaries did not extend to the location of the ignition, and the wildfire was nevertheless severe enough to result in several fatalities.

2.1.3.6. Conclusion of regarding ignition events

SCE has provided no indication that its FIPA events are consistent with the type of event that has led or could lead to serious catastrophic wildfire. While FIPA events could theoretically ignite a wildfire during a period of high wildfire risk, this should not be regarded as a likely scenario because:

- The FIPA event drivers rarely cause an ignition to propagate into a wildfire.
- FIPA event drivers are generally uncorrelated with factors that lead to more probable ignition of a wildfire and facilitate wildfire growth.
- During periods of high wildfire risk, an area that contains potential FIPA ignition hazards is likely to be de-energized.
- FIPA events are often recorded outside of the HFRA, where they are unlikely to cause ignition of a catastrophic wildfire.

For this reason, SCE should continue to use standard ignition history and supplement its history with properly weighted PSPS damage events that would have been potential wildfire ignition sources in lieu of PSPS.

2.1.4. Application of scaling values

As discussed in Section 2.1.1, SCE's WIM model appears to do an excellent job in predicting the consequence of tail-risk events. SCE additionally applies what it calls "scalars": an AFN customer scalar, non-residential critical infrastructure (NRCI) scalar, and a community fire risk assessment (CFRA) scalar.[37] The CFRA scalar incorporates a "Egress Constraint Index".

[37] SCE DRR SPD-SCE-2026RAMP-004-09.a-j, 42.a-b.

The term "scalar" does not refer to risk scaling. The application of scalar values is to represent actual risk factors that are not taken into account by the standard risk analysis. Risk scaling applies a judgement of value, whereas these scalars are intended to improve the accuracy of the risk assessment. While the methodology of the creation and application of these scalars should be analyzed, the general principle of adjusting risk using scaling values is valid. In the same way, MGRA suggests that wildfire smoke adjustments be made to risk even though the underlying science and methodology are still in flux. Moody's RMS 2.0 wildfire risk model contains a smoke component, so this is not as radical a step as SCE has suggested in the past.

Evidence that application of scalars is in the way suggested by SCE is appropriate was presented by MGRA in its PG&E GRC testimony.[38] While MGRA showed that PG&E's "egress" risk adjustment does not actually represent egress, but rather AFN populations, PG&E's data conclusively shows that AFN populations are at significantly greater risk of death in wildfire than the general public. Analysis of population age of Camp fire fatalities showed that it was significantly older than the general population (with those over 65 years of age making up 25% of the population of Paradise but making up 79% of fatalities).

2.1.5. Wildfire smoke

SCE was required to evaluate whether wildfire smoke had any disproportionate impact in Disadvantaged and Vulnerable Communities (DVCs).[39] SCE conducted a thorough review of this area, including work done in the OEIS Risk Mitigation Working Group (RMWG), findings by other utilities, and its own review of literature.[40] SCE concludes that:

- Wildfire smoke, particularly fine particulate matter (PM2.5), is linked to cardiovascular health effects.
- It is not possible to accurately predict which particular groups will be exposed to wildfire smoke because of the way smoke transports and spreads through the air, depending on weather conditions and other environmental factors.

---

[38] A.25-05-009; DIRECT TESTIMONY OF THE MUSSEY GRADE ROAD ALLIANCE PACIFIC GAS AND ELECTRIC COMPANY 2027 GENERAL RATE CASE PART I – GENERAL RATE CASE ISSUES; pp. 60-65.
https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2505009/8939/599154426.pdf
[39] RAMP; Appendix B; Environmental and Social Justice (ESJ) White Paper (p. 206/1026);
[40] RAMP; Appendix B; pp. 19-20, 25-29.

- It is difficult to attribute smoke exposure to wildfire in general and to specific wildfires, including utility-ignited wildfires.
- Nevertheless, medically vulnerable people are at proportionally greater risk from wildfire smoke, and DVCs may have an elevated number of people in vulnerable categories.

While complying with its DVC obligations, SCE is taking no tangible action with regard to wildfire smoke, joining the other major utilities in waiting for more definitive guidance from regulators and state authorities. This is a mistake. The trend in the scientific literature has been progressively more dire over time with regard to the lethality and morbidity of wildfire smoke. For example, Qui, et. al. 2025[41] estimate that the number of annual excess deaths between 2011 and 2020 due to wildfire smoke in the US is over 40,000, a number that could increase to over 70,000 by 2050 under a high warming climate change scenario. This is a total of 400,000 excess fatalities over the study period. The total number of wildfire fatalities linked to California utility wildfires in the same period is under 200, so in order for wildfire smoke to be a minor (<10%) contributor to the number of fatalities due to California utility wildfires, smoke from California utility wildfires would need to have constituted less than 0.005% of the overall PM2.5 US wildfire smoke burden. This is unlikely.

MGRA analyzed this problem extensively in its Informal Comments on the 2021 SDG&E RAMP.[42] At that time, SDG&E was applying a wildfire smoke correction that related excess fatalities to acres burned. SDG&E's methodology was flawed, and MGRA suggested an alternative based on the following simplified approach:

- Obtain number of excess fatalities attributable to wildfire smoke in a given area in a given time;
- Obtain the total number of acres burned that resulted in the excess fatalities;
- Calculate a number of excess fatalities per acre burned; and

---

[41] Qiu, M., et al.; 2025. Wildfire smoke exposure and mortality burden in the USA under climate change. Nature 647, 935–943. https://doi.org/10.1038/s41586-025-09611-w

[42] A.21-05-011/014; Safety Policy Division Staff Evaluation Report on SDG&E's and SoCalGas' Risk Assessment and Mitigation Phase (RAMP) Application Reports; November 5, 2021. Contains at p. 207/295:
MUSSEY GRADE ROAD ALLIANCE INFORMAL COMMENTS TO THE SAFETY POLICY DIVISION REGARDING SAN DIEGO GAS AND ELECTRIC COMPANY'S RAMP FILING; October 22, 2021; pp. 5-15

- Apply this as a safety attribute correction for simulated wildfires.

Using references current at the time, using this method the MGRA Comments showed that there was one wildfire smoke fatality per 1000 to 10,000 acres burned, depending on the reference used and the details of the method. A similar calculation today would need to use updated references.

The utility, regulator, and scientific argument against such an approach is that it crude, that the uncertainties are too large, that it doesn't account for fuels or weather, and that there is no accepted method for attributing fatalities in this manner. These are all correct statements, but the conclusion drawn from them fails from a framing perspective. By not including a wildfire smoke correction, the utility risk calculations are effectively stating that the number of wildfire smoke fatalities is zero or at least is negligible with respect to the risk of injury and death from direct exposure to wildfire. This assertion is readily disprovable under reasonable assumptions. Given the Dixie fire alone, using the MGRA 2021 estimates the number of attributable fatalities would range between ~100 and 1,000. The prediction that the number of fatalities from smoke from utility-linked wildfires is zero is almost certainly wrong. An ad-hoc method for projecting fatalities based on acres burned is also likely to be "wrong", in that it is uncertain and very likely biased by certain assumptions. The question that SPD should ask is which of these two approaches is the "least wrong". Because the potential impacts are so large, even an estimate with significant uncertainties and biases is better than ignoring the effect completely.

More rigorous approaches to smoke modeling are now being used by wildfire simulation product vendors. SCE is now using the Moody's RMS 2.0 model to simulate wildfire ignitions in its WIM model.[43] RMS 2.0 contains a smoke module:

"*Smoke hazard Simulation*

For each simulated wildfire, in addition to the fire and ember footprints, the model also includes a damaging smoke footprint developed based on latest models used in the wildfire community for smoke emission, transport, and deposition and U.S. Environmental Protection Agency's guidelines on hazardous smoke impacts in terms of concentrations of fine particulate matter known as PM2.5 (U.S. EPA, 2016). The model estimates smoke hazard based on simulating the amount of smoke

[43] SCE Power Law Whitepaper; p. 1.

particulate matter emitted using USDA Forest Service's Fuel and Fire Tools (FERA 2014), the distance of smoke particulate dispersion using USDA Forest Service's VSMOKE model (Lavdas, 1996), considering local uncertainties in wind direction and moisture conditions to account for the turbulent nature of wildfire conditions aiding smoke spread, and the concentration of deposited particulates.

The VSMOKE model, commonly used to assess air quality impacts on public health and visibility for prescribed burns, uses a Gaussian plume dispersion approach to estimate hourly downwind ground-level PM2.5 concentrations based on input emission profiles and wind information. In this approach, the extent of damaging smoke depends on the type of fuel burning, the time of the year, and fire size that drives the amount of smoke particulates emitted during the wildfire as well as weather conditions that determine the dispersion and deposition of potential smoke particulates."[44]

SPD should return to its original position in supporting a smoke correction to the safety attribute in wildfire risk models. SCE can move forward with this in its GRC filing by:

- Applying a fatalities per acre scaling correction to the safety attribute, and
- Investigating and evaluating whether the RMS 2.0 or a similar approach can be leveraged to obtain a more accurate estimation of wildfire smoke health risk.

The scientific evidence is overwhelming that by far the greatest number of fatalities occurring nationwide from wildfire is due to wildfire smoke rather than direct exposure to wildfire. SCE currently makes somewhat arbitrary adjustments to its risk model for AFN populations, communities at risk, critical infrastructure, and egress. SCE is right to do so. These are important considerations that are tricky to quantify and are not captured in its risk model. Wildfire smoke is a much larger effect that is being entirely ignored, and SCE has the opportunity to remedy this shortcoming in its GRC filing.

[44] RMS 2.0; p. 13.

2.2. Wildfire Risk Mitigation

2.2.1. Advanced Technologies

2.2.1.1. REFCL

REFCL greatly augments the effectiveness of covered conductor by addressing a number of the failure modes that can lead to ignition on covered circuits. Specifically, it is effective at reducing the risk from tree fall-in, a risk driver that may be accentuated during extreme weather. It thereby can help justify raising the PSPS threshold.

Tree fall-in has been responsible for a number of ignitions on covered conductor circuits over the last several years:

Year	Total Vegetation Related Ignitions	Fall-in, Covered Conductor Ignitions
2021	22	2
2022	20	4
2023	13	0
2024	27	3
2025	10	2

Table 6 - SCE vegetation related ignitions for primary, secondary, and service lines, and subset of ignitions from tree and heavy limb fall-ins.[45]

While REFCL is highly effective, it is costly and difficult to deploy and maintain. As a result, REFCL coverage is increasing slowly. In 2028, SCE projects there will still be 7,540 miles of distribution line in its HFRA without REFCL protection. By the end of 2030, it projects this will be 6,944 miles.[46] Therefore, REFCL protection needs to be concentrated in areas that will benefit from it most, specifically:

- Areas with significant tree fall-in potential,
- Areas with significant PSPS reliability risk,
- Areas that are not conducive or cost-effective for TUG.

[45] SCE DRR SCE-MGRA-001-09.a.
[46] SCE DRR MGRA-SCE-001-10.a-h and 11.a-h.

2.2.1.2. Hi-Z and DOPD Maturing / Operationalized Status

SCE's RAMP has placed its advanced technology pilots Hi-Z and DOPD into "Maturing / Operationalized" status. However, based on SCE's response to MGRA data requests on this topic,[47] this technology is still under evaluation rather than "mature", and it has not been deployed or operationalized. Additionally, the motivations for de-prioritizing these technologies are not clarified in SCE's data request response, with SCE stating that "*SCE was and is still investigating the need for future deployments. SCE is revisiting this for the upcoming GRC*."[48] SCE states that it cannot provide BCRs because these technologies are not considered to be in scope for the upcoming GRC. Also, no report detailing the effectiveness of the pilot to date is available.

This is concerning for several reasons:

- Both DOPD and Hi-Z are useful in scenarios involving tree fall-in, potentially amplifying the effectiveness of covered conductor.
- In its 2026-2028 GRC, SCE found that DOPD and Hi-Z potentially had very high Risk-Spend Efficiency (RSE) compared to other mitigations, though not as high as REFCL.
- Hi-Z relays can detect multi-phase faults, whereas REFCL is ineffective for multi-phase faults.
- Only 250 miles per year of REFCL coverage are planned from 2028 to 2030.

MGRA's testimony on SCE's 2026-2028 GRC analyzed DOPD and Hi-Z in significant detail, and SCE was able at that time to provide risk reduction estimates and calculations.[49] At that time pilot programs were well underway and it is surprising that no result is being presented in the current RAMP that would justify the de-prioritization of these technologies. The concern is that as these technologies are relatively inexpensive they may be more quickly and widely deployed than REFCL, particularly on circuits for which REFCL is inappropriate.

---

[47] SCE DRR MGRA-SCE-001-10.a-h and 11.a-h.
[48] Id.
[49] A.23-05-010; DIRECT TESTIMONY OF THE MUSSEY GRADE ROAD ALLIANCE SOUTHERN CALIFORNIA EDISON COMPANY 2025 GENERAL RATE CASE ERRATA; February 29, 2024. Updated May 13, 2024; pp. 81-84. (MGRA 2026-2028 Testimony)
https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7338/531383951.pdf

SCE should be requested to provide additional documentation on the pilots for these programs in its GRC filing and to provide BCR estimates if these are still considered potentially viable technologies.

2.2.2. Hardening: TUG and CCC Programs

According to SCE's estimation, its hardening and mitigation programs since 2018 have reduced wildfire overall residual risk by 66%.[50]

2.2.2.1. Completion of remaining HFRA circuits

SCE's presents its "*2029-2032 grid hardening estimate to deploy approximately 189 miles of TUG and 455 miles of CC, leaving approximately 236 HFRA circuit miles remaining unhardened.70 These remaining unhardened miles correspond to locations where circuit-level BCRs do not meet the cost-effectiveness thresholds discussed above (i.e., do not have BCRs >1)….As explained later in this chapter, pursuant to Alternative Plan #1 SCE would essentially 'finish off' these unhardened miles*. "[51]

Because of SCE's early adoption of covered conductor hardening, we are essentially in the "end game" of SCE's wildfire mitigation program. Regarding "finishing off" the unhardened miles, we need to ask whether these circuit segments still represent a significant threat. In its reply to DRR MGRA-SCE-001-05, SCE responds to MGRA's DR asking whether these remaining miles could result in wildfires of 10,000 acres or larger. SCE responds:

"*Specifically, among the remaining unhardened HFRA miles:*

- *Approximately 34 circuit miles are associated with an expected wildfire size exceeding 10,000 acres.*
- *Approximately 89 circuit miles are associated with a 98th percentile wildfire size exceeding 10,000 acres*."

[50] RAMP Workpapers; Chapter 4; Wildfire Overall Residual Risk; p. WP-1.
[51] RAMP; Chapter 4; p. 44.

So to "finish off" its largest wildfire threat, SCE would not need to address all 236 miles, but rather the highest consequence 34 circuit miles and possibly the 89 miles which could produce a 10,000 acre wildfire under extreme conditions.

SCE should provide similar estimates for miles with potential for the destruction of 500 structures. SCE's maximal alternative should contain only circuit segments with the potential for catastrophic losses.

2.2.2.2. Conversion of CC to TUG for "high-exposure" circuits

SCE's Alternative 2[52] suggests that "highest-exposure" circuits already mitigated with covered conductor might be converted to undergrounding. SCE defiess "highest-exposure":

"*For purposes of this analysis, SCE defines the highest-exposure existing Covered Conductor (CC) locations as those segments where covered conductor has been installed yet still have the highest overall pre-mitigated risk scores. This was done by risk ranking all overhead circuity regardless of whether it was covered or not. SCE then identified the point where the risk curve transitioned from linear to exponential. A $10 million risk threshold was used as the tail-risk tolerance boundary representing this transition point. The exponential portion of the curve contained 37 miles of existing covered conductor with residual wildfire risk.*"[53]

SCE also provides file MGRA-SCE-001_6b.xlsx, which identifies "*the highest wind gusts, weather station id, including date time and magnitude, measured on weather stations within 5 miles of the 37 miles targeted for Alternative 2*."[54]

This file was analyzed and found to contain 706 circuit segments. However, only a small fraction of these had recorded wind gusts above reasonable gust thresholds:

[52] RAMP; Chapter 4; p. 89.
[53] SCE DRR MGRA-SCE-001-06.a-c.
[54] Id.

Gust > 55 mph	Gust > 60 mph	Gust > 70 mph	Total
284	110	77	706
40%	16%	11%	

Table 7 - Number and percentage of "highest-exposure" CC segments with local wind speeds exceeding specified thresholds.[55]

While even a covered conductor mitigated circuit segment may be damaged by wind-blown debris, for these types of high wind condition PSPS is a highly effective supplement to covered conductor, as is REFCL, and in combination can reduce risk to levels comparable with undergrounding. PSPS use comes with reliability risk, but the results in Table 7 indicate that PSPS impacts will be relatively minor for the majority of the circuits. In general, circuits with lower local peak wind speeds experience PSPS less frequently and for shorter duration, as shown in MGRA's 2026-2028 SCE GRC Testimony:

Number of Stations	Gust Threshold (mph)	Annual Count
	58	250
	65	150
	70	92
	84	22
Measurements above threshold		
	58	5922
	65	2137
	70	1045
	84	126

Table 8 - Effect of wind gust threshold on number of weather stations exceeding threshold and total number of measurements over threshold.[56]

Based on these consideration SCE's proposal for undergrounding highest-exposure CC lines is unconvincing.

[55] File MGRA-SCE-001_6b-jwm-CCwinds.xlsx. (Github)
[56] MGRA SCE 2026-2028 GRC Testimony; p. 52.

2.2.2.3. TUG on secondary lines and BCR

SCE includes secondary lines in a TUG project only after it is approved and moves into the planning and engineering phases.[57] SCE uses BCR as an evaluation criterion for TUG projects:

"*The BCR evaluation is performed at the project level and is focused on the risk reduction associated with undergrounding primary conductor facilities*."[58]

However, the costs of including secondary lines are not used to evaluate BCR:

"*If secondary lines are determined to be feasible for inclusion, SCE does not perform a separate BCR calculation for secondary facilities added as part of a TUG project. The regional cost-per-mile assumptions used in the initial BCR evaluation are developed from historical undergrounding projects and therefore should inherently reflect the approximate expected costs associated with both primary and secondary undergrounding work. As previously stated, secondary line wildfire risk is not explicitly included within SCE's TUG BCR methodology. Costs associated with secondary facilities that are incorporated into approved TUG projects are reflected in overall project execution costs, and are ultimately captured through SCE's accountability and reporting processes*."[59]

It would therefore appear that the overall project cost (to the degree that secondary line undergrounding affects project cost) is under SCE control until the final auditing phase, when it is too late to make any corrections. For example, in a project with a favorable BCR for primaries, the secondaries could be particularly expensive and have limited wildfire mitigation benefit. In this case the "net" BCR of the project would be reduced by inclusion of the secondaries.

SPD should therefore:

- Require that before secondaries are finalized as part of the project, a "net" BCR including both the cost and benefit of secondary inclusion be calculated,
- Set standards for the inclusion of secondary undergrounding within the project, such as the BCR should not be reduced more than 10 or 20% by the inclusion of secondary lines.

[57] SCE DRR SPD-SCE-010-24.
[58] SCE DRR MGRA-003-05.a.
[59] SCE DRR MGRA-003-05.c.

2.2.3. SCE C8 Fully Subsidized Permanent Home Battery Backup

SCE provides the cost and battery capacity for the batteries it intends to use in its C8 Fully Subsidized Permanent Home Battery Backup Pilot.

> "*a. The estimated average battery cost is approximately $26,500 per battery system. This estimate represents the installed system cost, including the battery, labor, and permitting. b. The estimated battery capacity is approximately 10 kW*."[60] [sic kWh]

Based on research that was performed for the MGRA PG&E 2027 GRC testimony and cross-examination, these numbers appear to be extremely high, at $2,650 per kWh. An MGRA Exhibit contains a Bloomberg article that noted that worldwide lithium ion battery prices had fallen to $108 per kWh by the end of 2025.[61] While labor and permitting costs may be significant, the price to the ratepayers appears to be extreme and will need to be justified in the GRC filing.

3. CONCLUSION

These comments are provided in the hope that they provide some areas for further SPD investigation. MGRA will provide additional analysis and commentary in its official comments filed after the SPD report.

Submitted this 3rd day of September, 2026,

By: __*/S/*____***Joseph Mitchell***_____

Joseph Mitchell
M-bar Technologies and Consulting, LLC
19412 Kimball Valley Rd
Ramona, CA 92065
858 228 0089
On behalf of:
Mussey Grade Road Alliance

[60] SCE DRR MGRA-SCE-002-07.a-b
[61] A.25-05-009; MGRA Ex-06-E1; pp. 19-22/22.
https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2505009/9266/606263310.pdf

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 01:
Please provide geodatabase data (ESRI) supporting Maps 3-2a and b, Appendix B; pp. 13-14.

Response to Question 01:
SCE has provided a zipped geodatabase, MGRA-SCE-001-01, containing the layers from Maps 3-2a and b, Appendix B; pp. 13-14.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Phu Pham
Job Title: Manager
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 02.a-b:
Provide FIPA data (Fire Investigation Preliminary Analysis). Should provide most likely root cause, equipment, geographic location, time, and should indicate whether it was a CPUC reportable event.

a. If the involved equipment includes conductor, indicate whether it was bare conductor or covered conductor.

b. Alternatively, if geographic location cannot be provided or is confidential, provide wind speed at nearest weather station at time of ignition.

Response to Question 02.a-b:

Please see "MGRA_SCE_RAMP26-1-2.xlsx" for the list of FIPA events from 2021 through 2025. This list includes all ignitions at all voltage levels (primary, secondary, service, sub-transmission, transmission).

a. The FIPA data includes a column "Wire Type" which provides a value for the conductor type when distribution primary conductor was involved. The "Wire Type" field is primarily intended to evaluate the effectiveness of covered conductors. Although data is also collected for failed secondary, service, and underground assets, it does not specifically distinguish whether the conductor is covered or bare. As a result, this field may be left blank for those asset types.
b. All events have latitude and longitude coordinate information, and therefore part (b) is not needed.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Phu Pham
Job Title: Manager
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 03:
Does the ignition data, for example Contact from Object (CFO) data captured in Table II-5, Table II-6 and other SCE statistics represent CPUC reportable ignitions or is it based on FIPA data?

Response to Question 03:

It is not clear to SCE what is meant by "other SCE statistics." However, the ignition data presented in Table II-5 and Table II-6 are based on FIPA data. The data reflects ignition events captured through SCE's Fire Incident and Preliminary Analysis (FIPA) process, which includes a broader set of ignition incidents than those required to be reported to the CPUC.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Phu Pham
Job Title: Manager
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 04:
Provide all ignition data for EFF.

Response to Question 04:

Please see "MGRA_SCE_RAMP2026-1-4" for the list of FIPA events from 2021 through 2025 for all EFF (Equipment Failure/Facility). The list includes all ignitions involving EFF at all voltage levels, including equipment inside substation.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Paolo Joson
Job Title: Predictive Analytics/Data Science, Sr. Specialist
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 05:
SCE's grid hardening estimate (p. 44) leaves approximately 236 HFRA miles unhardened miles do not meet cost-effectiveness thresholds. Do any of the remaining 236 HFRA circuit miles have the potential to ignite a wildfire larger than 10,000 acres?

Response to Question 05:

Yes. Although the remaining unhardened HFRA miles were not included in SCE's proposed grid hardening portfolio, some of those miles may still have the potential to contribute to large wildfire events. SCE notes that a modeled result indicating an expected wildfire size below 10,000 acres does not mean that a wildfire exceeding 10,000 acres is impossible or technically infeasible. Rather, the result reflects the specific assumptions and outputs of the risk modeling performed for the RAMP.

Specifically, among the remaining unhardened HFRA miles:

- Approximately 34 circuit miles are associated with an expected wildfire size exceeding 10,000 acres.
- Approximately 89 circuit miles are associated with a 98th percentile wildfire size exceeding 10,000 acres.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Daniel Komula
Job Title: Senior Advisor
Received Date: 8/11/2026

Response Date: 8/26/2026

Question 06.a-c:
On p. 87, what are the "highest-exposure existing CC locations" and how is this term defined.

a. For the 37 miles contemplated in Alternative 2, provide geodatabase data in ESRI format that provides the locations.

b. Identify the highest wind gusts, weather station id, including date time and magnitude, measured on weather stations within 5 miles of the 37 miles targeted for Alternative 2.

c. What is the estimated improvement in reliability that would be achieved by Alternative 2 and what is its BCR?

Response to Question 06.a-c:
For purposes of this analysis, SCE defines the highest-exposure existing Covered Conductor (CC) locations as those segments where covered conductor has been installed yet still have the highest overall pre-mitigated risk scores. This was done by risk ranking all overhead circuity regardless of whether it was covered or not. SCE then identified the point where the risk curve transitioned from linear to exponential. A $10 million risk threshold was used as the tail-risk tolerance boundary representing this transition point. The exponential portion of the curve contained 37 miles of existing covered conductor with residual wildfire risk.

a) See the attached file, MGRA-SCE-001-6a.zip.
b) See the attached file, MGRA-SCE-001_6b.xlsx.
c) The BCR for alternative 2 is provided in Table VIII-41 in Chapter 4 of SCE's RAMP application and is also provided below.

Table** Error! No text of specified style in document.**-1
Alternative Plan #2 Programmatic Wildfire Estimated Spend ($000s) and Benefit-Cost Ratios

2026 RAMP ID	2026 RAMP Control / Mitigation Name	O&M 2029 - 2032 ($000s)	Capital 2029 - 2032 ($000s)	Total 2029 - 2032 ($000s)	Benefit Cost Ratios		
					WACC	Societal	Hybrid
C1	Wildfire Covered Conductor Program (WCCP)		$467,351	$467,351	9.18	13.24	10.01
C2	Targeted Undergrounding		$1,060,743	$1,060,743	10.03	66.73	10.29
C3	Fire Resistant (FR) Wrap Expanded Deployment		$28,113	$28,113	3.37	8.86	4.49
C4	Rapid Earth Fault Current Limiters - Grounding Conversion		$34,207	$34,207	8.41	20.34	8.49
C5	Rapid Earth Fault Current Limiters - Ground Fault Neutralizer		$349,589	$349,589	27.27	65.44	27.84
C6	Distribution Early Fault Detection (EFD)		$45,813	$45,813	9.23	14.55	9.35
C7	Transmission Early Fault Detection (EFD)		$15,599	$15,599	13.34	20.53	13.50
C8	Inspections for Vegetation Clearances from Distribution Lines	$1,119,109		$1,119,109	0.51	0.51	0.51
C9	Distribution High Fire Risk Informed Inspections	$640,386	$546,134	$1,186,519	24.08	47.49	24.53
C10	Inspections for Vegetation Clearances from Transmission Lines	$117,922		$117,922	0.09	0.09	0.09
C11	Transmission High Fire Risk Informed Inspections	$102,042	$84,766	$186,807	9.55	18.85	9.71
C12	Generation High Fire Risk Inspections	$1,326		$1,326	2.45	4.84	2.50
C13	Distribution Infrared Scanning	$3,562		$3,562	0.15	0.29	0.15
C14	Transmission Infrared (IR) and Corona Scanning	$875		$875	0.12	0.23	0.12
C15	Hazard Tree Management Program	$128,574		$128,574	1.23	4.16	1.27
C16	Dead and Dying Tree Removal	$158,933		$158,933	0.53	1.80	0.55
C17	Compliance Structure Brushing	$40,492		$40,492	40.45	40.50	40.62
C18	Expanded / Additional Structure Brushing	$111,343		$111,343	15.24	15.23	15.34
C19	Transmission Proactive Splice Shunting		$30,413	$30,413	2.64	6.90	2.69
M1	Sub-Transmission OH Conductor Replacement		$202,010	$202,010	1.51	3.94	1.53
	Total - Alternative Plan 2	**$2,424,564**	**$2,864,736**	**$5,289,300**	**11.33**	**23.61**	**11.65**

Alternative plan #2 has an estimated 14.1% improvement in reliability from 2029 – 2032.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Davi Ibarra
Job Title: Senior Advisor
Received Date: 8/11/2026

Response Date: 8/18/2026

Question 07.a-b:
Provide technical information available for C8 Fully Subsidized Permanent Home Battery Backup Pilot.

a. What is the estimated battery cost? ($25 k/battery – Table IX-54)
b. What is the estimated battery capacity?

Response to Question 07.a-b:

The cost and capacity estimates in SCE's 2026 RAMP Report, Table IX-54 are preliminary, planning-level assumptions and may be refined during implementation and/or procurement.

a. The estimated average battery cost is approximately $26,500 per battery system. This estimate represents the installed system cost, including the battery, labor, and permitting.
b. The estimated battery capacity is approximately 10 kW.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Daniel Komula
Job Title: Senior Advisor
Received Date: 8/11/2026

Response Date: 8/18/2026

Question 08.a:
In Appendix A, p. 5, Table 1 "Alternative RRU Selection for Wildfire Controls and Mitigations
a. For Proposed Control C2 – TUG, Alternative 1 is Covered Conductor (CC), is Covered Conductor combined with REFCL for the alternative? If not, why not?

Response to Question 08.a:

As expressly discussed in SCE's Reply to Protests,[1] SCE had an inadvertent error in Table 1 that mislabeled Alternative 2 for C1 – WCCP and C2 0- TUG. The corrected table is below. SCE also notes here (and noted in its Reply to Protests) that the *narrative* in this Appendix correctly describes Alterative 2 as CC + REFCL for both of these controls.

Proposed Control	Alternative 1	Alternative 2
C1 - WCCP	Targeted Undergrounding (TUG)	Covered Conductor Paired with Rapid Earth Fault Current Limiters (REFCL) – Ground Fault Neutralizer
C2 - TUG	Covered Conductor (CC)	Covered Conductor Paired with Rapid Earth Fault Current Limiters (REFCL) – Ground Fault Neutralizer
C3 - FR Wrap Expanded Deployment	Installing a Composite Pole	TUG
C4 - (REFCL) – Grounding Conversion	Distribution Open Phase Detection (DOPD)	High Impedance Relays (Hi-Z)
C5 - (REFCL) – Ground Fault Neutralizer	DOPD	Hi-Z
C6 - EFD – Distribution	GridScope Sensor Technology	Distribution Infrared (IR) Scanning
C7 - EFD – Transmission	GridScope Sensor Technology	Transmission Infrared (IR) Scanning and Corona Scanning
C8 - Inspections for Vegetation Clearances from Distribution Lines	Remove Entire Tree	TUG Circuits in High-Risk Vegetation Areas
C9 - Distribution High Fire Risk Informed Inspections - Ground and Aerial	Pole Replacements	All Assets Inspected Annually
C10 - Inspections for Vegetation Clearances from Transmission Lines	Remove Entire Tree	Targeted Undergrounding of Circuits in High-Risk Vegetation Areas
C11 - Transmission High Fire Risk Informed Inspections Ground and Aerial	Pole Replacements	All Assets Inspected Annually
C12 – Generation High Fire Risk Inspections (HFRI)	N/A	N/A
C13 - Distribution Infrared (IR) Scanning	N/A	N/A

[1] Southern California Edison Company's Reply To Responses And Protests, p. 5.

Proposed Control	Alternative 1	Alternative 2
C14 – Transmission Infrared (IR) Scanning and Corona Scanning	N/A	N/A
C15 - Hazard Tree Management Program (HTMP)	Remove All Subject Trees in HFRA	TUG Circuits with Hazard Trees
C16 - Dead and Dying Tree Removal	Remove all Subject Trees in HFRA	Targeted Undergrounding of Circuits with Dead and Dying Trees
C17 - Compliance Structure Brushing	Fire-Resistant Ground Treatment	Targeted Undergrounding (TUG)
C18 - Expanded / Additional Structure Brushing	Fire-Resistant Ground Treatment	Targeted Undergrounding (TUG)
C19 - Transmission Proactive Splice Shunting	X-ray Inspection with Remediation	Reconductoring
M1 - OH Conductor Replacement (Small Wire and ESD)	Transmission Infrared (IR) Scanning and Corona Scanning	TUG Sub-transmission Lines

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Phu Pham
Job Title: Manager
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 09.a-b:
Provide data on tree fall-ins and heavy limb fall-ins that show:
a. What fraction of tree fall-ins and heavy limb fall-ins result in ignition for covered conductor?
b. What fraction of tree fall-ins and heavy limb fall-ins result in phase to phase contact for covered conductor (due to broken insulation).

Response to Question 09.a-b:

a) Please see the table below for a summary of vegetation-involved ignitions. The data is across all SCE voltage levels (primary, secondary, service).

Year	Total Vegetation Related Ignitions	Fall-in, Covered Conductor Ignitions
2021	22	2
2022	20	4
2023	13	0
2024	27	3
2025	10	2

b) SCE does not readily maintain or track this information at this time.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Andrew Swisher
Job Title: Consulting Engineer
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 10.a-h:

Regarding SCE's Distribution Open Phase Detection

a. How many DOPD units will have been installed in the HFTD/HFRA at the end of 2028?
b. How many circuit miles will be protected by DOPD in the HFTD/HFRA at the end of 2028?
c. How many miles of overhead will not be protected by either REFCL or DOPD,
   a) At the end of 2028?
   b) At the end of 2030?
d. Provide the efficiency of DOPD as a risk mitigation for all risk drivers.
e. Provide the efficiency of DOPD+CC as a risk mitigation for all risk drivers.
f. Provide the BCR of DOPD.
   a) For circuits installed in 2026-2028 period,
   b) For all circuits that would be unprotected by either REFCL or DOPD in 2030.
g. What are the reasons that DOPD was not chosen for further deployment in the HFTD after 2030?
h. If there are any reports or documentation providing SCE's analysis of the DOPD technology justifying its decision not to expand the program during the current GRC period, please provide non-confidential versions.

Response to Question 10.a-h:

a) How many DOPD units will have been installed in the HFTD/HFRA at the end of 2028?
   - SCE's deployment plan for DOPD extends through 2026 and includes approximately 28 standalone DOPD installations and 19 paired DOPD installations. The paired installations are two reclosers partnered together with communications. Installation quantities are not yet established for 2027 and 2028.

b) How many circuit miles will be protected by DOPD in the HFTD/HFRA at the end of 2028?
   - DOPD is presently in alarming mode, and while in alarming mode the DOPD system does not provide circuit protection. The performance monitoring of DOPD is still ongoing and a determination has not been made if the system will be configured to trip mode for providing line protection by the end of 2028 or some future date.

c) How many miles of overhead will not be protected by either REFCL or DOPD,
   For response to this question SCE assumes "…miles of overhead…" is meant to ask for the length of overhead distribution voltage circuit miles which traverse HFRA.

a) At the end of 2028?
   - Refer to 10b for DOPD circuit protection specifics. SCE can approximate the HFRA circuit milage protected by REFCL using the identified REFCL GFN project scope through 2028. GFN commissioning may occur in the subsequent year of completing construction, but for this approximation it is assumed the commissioning and construction are occurring in the same year. With the above assumptions, the estimated unprotected overhead HFRA primary distribution miles from REFCL are expected to be approximately 7,540.

b) At the end of 2030?
   - Refer to 10b for DOPD circuit protection specifics. SCE can approximate the HFRA circuit milage protected by REFCL using the identified REFCL GFN project scope through 2030. With the above assumptions, the estimated unprotected overhead HFRA primary distribution miles from REFCL are expected to be approximately 6,944.

d) Provide the efficiency of DOPD as a risk mitigation for all risk drivers.
   - SCE did not conduct this analysis as part of our RAMP filing since we did not forecast any scope in 2029 – 2032. To the extent that SCE proposes funding in 2029 – 2032 we plan to provide this in our upcoming GRC.

e) Provide the efficiency of DOPD+CC as a risk mitigation for all risk drivers.
   - SCE did not conduct this analysis as part of our RAMP filing since we did not forecast any scope in 2029 – 2032. To the extent that SCE proposes funding in 2029 – 2032 we plan to provide this in our upcoming GRC.

f) Provide the BCR of DOPD.
   - For circuits installed in 2026-2028 period,
   - For all circuits that would be unprotected by either REFCL or DOPD in 2030.
     - SCE did not conduct this analysis as part of its 2026 RAMP because SCE did not estimate any DOPD scope during the 2029-2032 period. Accordingly, DOPD was not included as a wildfire mitigation in SCE's 2026 RAMP portfolio and does not contribute to the baseline or incremental wildfire risk reduction reflected in the RAMP analyses. To the extent SCE seeks funding for DOPD-related activities during the 2029 GRC cycle, SCE would provide the appropriate benefit-cost analysis in that proceeding.

       Additionally, as noted in SCE's response to part (b), the DOPD system is currently operating in alarming mode. While operating in alarming mode, DOPD provides notification and situational awareness capabilities but does not provide circuit-tripping protection. As a result, DOPD in alarming mode is not expected to produce the risk-reduction benefits associated with a protection-enabled deployment. Because it is currently unclear whether

DOPD will be enabled for tripping protection by the end of 2028, SCE has not developed a benefit-cost ratio for DOPD operating solely in alarming mode.

g) What are the reasons that DOPD was not chosen for further deployment in the HFTD after 2030?
   - At the time of filing RAMP, SCE was and is still investigating the need for future deployments. SCE is revisiting this for the upcoming GRC. During the 2026–2028 period, SCE intends to complete planned installation of DOPD units on HFRA distribution circuits. In parallel, SCE will continue to monitor the effectiveness of the technology to operate protection as intended to limit ignition risk. In addition, SCE will continue to refine alarm verification, response protocols, and operational integration to support the potential broader use of open phase detection capabilities on SCE's electric system. The 2026–2028 work emphasizes integrating SCE's Field Area Network (FAN) for control and monitoring of DOPD performance.

     SCE's evaluation of the technology is intended to help inform whether it will be part of its portfolio to reduce wildfire risk. SCE is continuing to evaluate the long-term viability and may choose to implement the technology more broadly at a later time.

h) If there are any reports or documentation providing SCE's analysis of the DOPD technology justifying its decision not to expand the program during the current GRC period, please provide non-confidential versions.
   - SCE does not currently have such a report. SCE is working to continue installations of DOPD during the current GRC period and is still evaluating future deployments in the upcoming GRC cycle.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Andrew Swisher
Job Title: Consulting Engineer
Received Date: 8/11/2026

Response Date: 8/25/2026

Question 11.a-h:
Regarding SCE's High Impedance Fault Detection Program C25 (Hi-Z)

a. How many Hi-Z units will have been installed in the HFTD/HFRA at the end of 2028?
b. How many circuit miles will be protected by Hi-Z in the HFTD/HFRA at the end of 2028?
c. How many miles of overhead will not be protected by either REFCL or Hi-Z,
   a) At the end of 2028?
   b) At the end of 2030?
d. Provide the efficiency of Hi-Z as a risk mitigation for all risk drivers.
e. Provide the efficiency of Hi-Z+CC as a risk mitigation for all risk drivers.
f. Provide the BCR of Hi-Z.
   a) For circuits installed in 2026-2028 period,
   b) For all circuits that would be unprotected by either REFCL or Hi-Z in 2030.
g. What are the reasons that Hi-Z was not chosen for further deployment in the HFTD after 2030?
h. If there are any reports or documentation providing SCE's analysis of the Hi-Z technology justifying its decision not to expand the program during the current GRC period, please provide non-confidential versions.

Response to Question 11.a-h:

a) How many Hi-Z units will have been installed in the HFTD/HFRA at the end of 2028?
   - SCE's present estimate for HiZ relay applications extends through 2026, for approximately 75 installations.

b) How many circuit miles will be protected by Hi-Z in the HFTD/HFRA at the end of 2028?
   - HiZ relays are presently in alarming mode, and while in alarming mode the HiZ relay detection system does not provide circuit protection. The performance monitoring of HiZ relays is still on-going; and determination has not been made if the system will be configured to trip mode for providing line protection by the end of 2028 or some future date.

c) How many miles of overhead will not be protected by either REFCL or Hi-Z,
   a) At the end of 2028?
      - Please refer to 11b for HiZ relay circuit protection specifics. Refer to response provided for Question 10c which provides the estimate of distribution HFRA circuit miles not protected by REFCL GFN.

b) At the end of 2030?
   - Please refer to 11b for HiZ relay circuit protection specifics. Refer to response provided for Question 10c which provides the estimate of distribution HFRA circuit miles not protected by REFCL GFN.

d) Provide the efficiency of Hi-Z as a risk mitigation for all risk drivers.
   - SCE did not conduct this analysis as part of our RAMP filing since we did not estimate any scope in 2029 – 2032. To the extent that SCE proposes funding in 2029 – 2032, we will provide this showing in our upcoming GRC.

e) Provide the efficiency of Hi-Z+CC as a risk mitigation for all risk drivers.
   - SCE did not conduct this analysis as part of our RAMP filing since we did not estimate any scope in 2029 – 2032. To the extent that SCE proposes funding in 2029 – 2032 we will provide this in our upcoming GRC.

f) Provide the BCR of Hi-Z.
   - For circuits installed in 2026-2028 period,
   - For all circuits that would be unprotected by either REFCL or Hi-Z in 2030.
     - SCE did not conduct this analysis as part of its 2026 RAMP because SCE did not estimate any Hi-Z scope during the 2029-2032 period. Accordingly, Hi-Z was not included as a wildfire mitigation in SCE's 2026 RAMP portfolio and does not contribute to the baseline or incremental wildfire risk reduction reflected in the RAMP analyses. To the extent SCE seeks funding for Hi-Z-related activities during the 2029 GRC cycle, SCE would provide the appropriate benefit-cost analysis in that proceeding.

       Additionally, as noted in SCE's response to part (b), the Hi-Z system is currently operating in alarming mode. While operating in alarming mode, Hi-Z provides notification and situational awareness capabilities but does not provide circuit-tripping protection. As a result, Hi-Z in alarming mode is not expected to produce the risk-reduction benefits associated with a protection-enabled deployment. Because it is currently unclear whether Hi-Z will be enabled for tripping protection by the end of 2028, SCE has not developed a benefit-cost ratio for Hi-Z operating solely in alarming mode.

g) What are the reasons that Hi-Z was not chosen for further deployment in the HFTD after 2030?
   - At the time of filing RAMP SCE was and is still investigating the need for future deployments. SCE is revisiting this for the upcoming GRC. During the 2026–2028 period, SCE intends to complete Hi-Z relay installations on a select set of circuits and evaluate the effectiveness and viability of the technology. The evaluation will help inform SCE's strategy for implementing future protection technologies across its HFRA. SCE is deploying and evaluating a set of protection technologies that includes Hi-Z, DOPD, TOPD, and REFCL to determine which possible combination of protection technologies paired with other wildfire hardening strategies reduce the

Commented [SV1]: Kris to resume editing and review here

most risk cost-effectively.

SCE's evaluation of the technology is intended to help inform whether it will be part of its portfolio to reduce wildfire risk. SCE is continuing to evaluate the long-term viability and may choose to implement the technology more broadly at a later time.

h) If there are any reports or documentation providing SCE's analysis of the Hi-Z technology justifying its decision not to expand the program during the current GRC period, please provide non-confidential versions.
   - SCE does not have such a report. SCE is working to continue installations HiZ relays during the current GRC period and is still evaluating future deployments in the upcoming GRC cycle.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Daniel Komula
Job Title: Senior Advisor
Received Date: 8/11/2026

Response Date: 8/18/2026

Question 12:
Provide a non-confidential version of the Logic20/20 WIM v1 documentation.

Response to Question 12:

SCE objects to this request as it is overly broad, unreasonable, and unduly burdensome. Subject to and without waiving these objections, SCE responds as follows:

Providing a non-confidential version of the referenced WIM documentation would require review of extensive materials and redaction on a page-by-page basis. Without waiving any of its rights, SCE notes that it is willing to discuss with MGRA (at a mutually convenient time) whether an appropriate Non-Disclosure Agreement or Protective Order can be put in place to help safeguard confidentiality.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 1

To: MGRA
Prepared by: Daniel Komula
Job Title: Senior Advisor
Received Date: 8/11/2026

Response Date: 8/18/2026

Question 13:
Provide a non-confidential version of WIM Model- Logic 2020 Shared 10.24.25.pdf.

Response to Question 13:

SCE objects to this request as it is overly broad, unreasonable, and unduly burdensome. Subject to and without waiving these objections, SCE responds as follows:

Providing a non-confidential version of the referenced WIM documentation would require review of extensive materials and redaction on a page-by-page basis. Without waiving any of its rights, SCE notes that it is willing to discuss with MGRA (at a mutually convenient time) whether an appropriate Non-Disclosure Agreement or Protective Order can be put in place to help safeguard confidentiality.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 01:
Please provide for Asset Point data for Camera, Support Structure, and Weather Station.

Response to Question 01:
SCE has provided Asset Point data for Camera and Weather Station in the attached zipped file MGRA-SCE-RAMP26-002, which contains geodatabases for Q1 through Q4 2025 and Q1 and Q2 2026.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 02:
Provide Asset Line data for Transmission Line (as permitted as non-confidential), Primary Distribution Line, and Secondary Distribution Line.

Response to Question 02:
SCE has provided Asset Line data for Primary Distribution Line and Secondary Distribution Line in the zipped file MGRA-SCE-RAMP26-002 (attached to MGRA-SCE-002 01), which contains geodatabases for Q1 through Q4 2025 and Q1 and Q2 2026.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 03:
Provide PSPS Event data. Include Event Log, Event Line, Event Polygon data. Please exclude customer meter data. Provide all PSPS Event Asset Damage data. Data should include time, duration

Response to Question 03:
SCE has provided PSPS Event Log, PSPS Event Line, PSPS Event Polygon, and all reasonably available PSPS Damage data in the zipped file MGRA-SCE-RAMP26-002 (attached to MGRA-SCE-002 01), which contains geodatabases for Q1 through Q4 2025 and Q1 and Q2 2026. There is no PSPS Damage data for the period Q2 2025 through Q2 2026. In addition, there is no PSPS Event data for Q1 2026.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 04:
Provide Risk Event Point data, including Wire Down, Ignition, Transmission unplanned outage (as classified non-confidential), Distribution Unplanned Outage data, Distribution Vegetation Caused Unplanned Outage, Risk Event Asset Log. Attributes should include location, time, and cause information.

Response to Question 04:
SCE has provided the reasonably available Risk Event Point data, including Wire Down Event, Ignition, and Unplanned Outage, in the zipped file MGRA-SCE-RAMP26-002 (attached to MGRA-SCE-002 01), which contains geodatabases for Q1 through Q4 2025 and Q1 and Q2 2026.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 05:
Under Initiatives, please provide Grid Hardening data, including Hardening Log, Hardening Point, and Hardening Line data. Inspection data is not requested at this time.

Response to Question 05:
SCE has provided the available Grid Hardening Point data in the zipped file MGRA-SCE-RAMP26-002 (attached to MGRA-SCE-002 01), which contains geodatabases for Q1 through Q4 2025 and Q1 and Q2 2026.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 06:
Under Other Required Data, please provide Red Flag Warning Day polygon data including dates and duration.

Response to Question 06:
SCE has provided Red Flag Warning day Polygon data in the zipped file MGRA-SCE-RAMP26-002 (attached to MGRA-SCE-002 01), which contains geodatabases for Q1 through Q4 2025 and Q1 and Q2 2026. There is no Red Flag Warning Day Polygon data for Q1 2026.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 07.a:
Please provide a layer indicating calculated circuit-level risk using the methodology presented in the RAMP.

a. If independent probability and consequence layers exist, please provide these independently as well.

Response to Question 07.a:
SCE has provided a zipped geodatabase, MGRA-SCE-002-07a, indicating circuit-level risk using the methodology presented in the RAMP.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 2

To: MGRA
Prepared by: Jessica Vibbert
Job Title: GIS Advisor
Received Date: 8/11/2026

Response Date: 8/21/2026

Question 08:
If SCE maintains that providing specific data in response to the above requests would violate confidentiality as it has asserted it please provide a justification for each of the asserted violations. Likewise, if requested data cannot be provided for other reasons please provide justifications.

Response to Question 08:
The following GIS data has been withheld because they contain location-specific infrastructure information that SCE classifies as confidential and sensitive: Support Structure and Transmission Line. Disclosure of this data would reveal the locations of electric system assets, and therefore SCE is not providing this information to protect the confidentiality and security of its infrastructure.

In addition, Transmission Unplanned Outage, Distribution Unplanned Outage, Distribution Vegetation-Caused Unplanned Outage, Risk Event Asset Log, and Grid Hardening Log are not provided because these datasets are no longer included in the OEIS QDR schema.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 3

To: MGRA
Prepared by: Phu Pham
Job Title: Manager
Received Date: 8/14/2026

Response Date: 8/28/2026

Question 01.a-c:
In regard to Data Request Response SPD-SCE-2026RAMP-010: 14.a-b:
a. What is the definition of "Pole Line Hardware" as an ignition Sub-Driver category?
b. Why are there 11 events categorized as "Pole Line Hardware" observed in 2024 when the mean value for prior years is less than 1 event?
c. How does SCE account for the observation of 46 and 33 events categorized as "Birds Nest" in 2023 and 2024 whereas there were no more than 2 such categorizations in the 2019-2022 period?

Response to Question 01.a-c:

Response to A) "Pole Line Hardware" refers to a category of miscellaneous equipment that does not fall under specific asset type. Examples include guy wire, anchor rod, crossarm support braces, wildlife protection.

Response to B and C) Since 2022, enhancements to SCE's Fire Incident and Preliminary Analysis (FIPA) data collection, investigation, and reporting processes have allowed SCE to capture and classify event information in greater detail. As a result, events that may previously have been grouped into broader categories are now more often identified and recorded under specific categories such as "Pole Line Hardware" and "Birds Nest." Accordingly, the increase in the number of events reported in these categories is largely due to improvements in event identification, documentation, and classification practices, rather than solely reflecting an increase in the occurrence of such events. While SCE believes these process improvements contributed to the increase in reported event counts, SCE cannot determine with precision the extent to which the observed changes are attributable to improved classification practices versus changes in the underlying occurrence of events.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 3

To: MGRA
Prepared by: Phu Pham
Job Title: Manager
Received Date: 8/14/2026

Response Date: 8/28/2026

Question 02:
Provide a version of 02.a_SPD-SCE-2026RAMP-004-02a_20260615.xlsx that shows CPUC reportable ignitions instead of FIPA events, in other words clearly classifying ignitions by SCE-defined risk drivers.

Response to Question 02:

Please see attached "MGRA-SCE-RAMP26_DataRequest3-2_20260826.xlsx" for the updated column with "CPUC Reportable."

"CPUC Reportable" shows True for CPUC reportable and False for a FIPA ignition for each of the events reported.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 3

To: MGRA
Prepared by: Charles Tong
Job Title: Data Scientist
Received Date: 8/14/2026

Response Date: 8/28/2026

Question 03.a-c:
With regard to Workpaper Chapter 4 "Conditional Probability of Ignition Assumptions":
a. What is the original data source for Table Breakdown of Historical Ignitions to Derive Conditional Probability Percentages?
b. Please provide the original data for these tables, including all non-confidential fields.
c. Do ignitions in these tables actually correspond to historical utility wildfire ignitions?
a) These show 4/5 years with over 20 ignitions leading to structure loss. This appears incongruous with utility wildfire records in which structure loss wildfires have been relatively rare in recent years. Please resolve this apparent incongruity.
b) If in fact these are historical utility ignitions please provide the data in the Historical Ignitions Tables showing how each of Cond 1, Cond2, and Cond 3 are classified into SCE's risk driver categories.

Response to Question 03.a-c:

a. The data source for this table comes from SCE's Fire Investigation Preliminary Analysis (FIPA) database, and SCE's ESIR reports to CPUC that are related to ignitions.

b. Please see the attached file for the original data.

c. These ignitions correspond to historical utility wildfire ignitions.

    a. SCE's Condition 3 is intended to identify ignitions that occur under environmental and fire-behavior conditions associated with elevated fire weather conditions (e.g., dry fuels with or without extreme wind conditions) while recognizing that many ignitions under these conditions may not ultimately result in significant realized impacts due to several reasons. Accordingly, an ignition may be classified as Condition 3 even if it ultimately results in no structures damaged or destroyed and burns less than 200 acres. In such circumstances, the absence of realized structure impacts may reflect successful suppression actions, limited structure exposure, or other event-specific factors that reduced the ultimate consequences of the fire. Condition 3 represents ignitions that happen during high fire weather conditions that

may result in structures damaged or destroyed. Consistent with the approach described in SCE's 2026 RAMP Wildfire Power Law White Paper, SCE's classification framework seeks to characterize wildfire consequence potential rather than relying exclusively on realized historical outcomes. In other words, SCE hopes to mitigate against the Lucretius Problem, which is the cognitive bias to think that the worst events of the past are the worst possible that could ever occur.

b. Please see the attached file.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 3

To: MGRA
Prepared by: Charles Tong
Job Title: Data Scientist
Received Date: 8/14/2026

Response Date: 8/28/2026

Question 04.a-b:
With regard to SCE response to SPD Data Request 10, Question 37, file "37_spd_sce_2026ramp_010_q37_condition3_data.csv":

a. Event 14358, occurring on 11/6/2024 in the HFRA, was a fire of 19,904 acres that resulted in the destruction of 136 structures. Please confirm whether this was the Mountain fire (https://en.wikipedia.org/wiki/Mountain_Fire_(2024)).

b. If the event indeed represents the Mountain fire, this fire origin was linked to a tractor clearing brush. Why is it linked to Distribution in the Condition 3 dataset?

Response to Question 04.a-b:

a. The event was the Mountain Fire.

b. Around the time of the event, SCE submitted an Electric Safety Incident Report (ESIR) as an extreme precaution because it did not know for certain that this event was not caused by a utility; attached is a pdf file containing the report. One of the circuits identified as a potential suspect is at the Distribution level. Because a report was still filed, this record was kept for the RAMP application.

   SCE is continuing to refine and assess the modeling assumptions that underpin SCE's risk analysis and preliminary cost estimates and scope projections as part of its preparation process for presenting GRC forecasts in May of 2027. Any resulting refinements that occur in the one-year period between the filing of SCE's RAMP and the filing of SCE's GRC Application will be duly incorporated into SCE's Test Year 2029 GRC modeling as appropriate.

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - 0 0 3

To: MGRA
Prepared by: Angelo Rivera
Job Title: Sr. Advisor
Received Date: 8/14/2026

Response Date: 8/31/2026

Question 05.a-c:
With regard to SCE response to SPD Data Request 10, Question 24, SCE states that "Once a TUG project is approved and moves into the planning and engineering phases, secondary facilities are evaluated as part of project design. Secondary lines that are in-line with or attached to the approved TUG scope are undergrounded where feasible…"

a. Does SCE use BCR as an input in selecting circuit segments for undergrounding and specifying TUG projects?

b. In cases where SCE has included secondary lines within the scope of a TUG project, what is the range of costs of the secondary additions as a fraction of the overall TUG costs?

c. If secondary lines are added to the scope of the project afterwards, does SCE recalculate BCR for the project including both primary and secondary components?

Response to Question 05.a-c:

a) Yes. SCE uses benefit-cost ratio (BCR) as one of the inputs in identifying and prioritizing Targeted Undergrounding (TUG) opportunities. Consistent with SCE's RAMP methodology, TUG project selection is based on a risk-informed evaluation that considers wildfire risk reduction potential and associated project costs. The BCR evaluation is performed at the project level and is focused on the risk reduction associated with undergrounding primary conductor facilities. Wildfire risk associated with secondary lines and service drops is not explicitly included in the TUG BCR methodology or mitigation effectiveness calculation

b) The proportion of secondary undergrounding included within a TUG project varies significantly based on project-specific characteristics, including customer density, system configuration, terrain, and constructability requirements. As a result, SCE does not apply a standard percentage or typical fraction of secondary line undergrounding across all TUG projects. For example, a TUG project located near a community may require a greater amount of secondary undergrounding to serve adjacent customers, whereas a project in a remote mountainous area may primarily consist of primary facilities serving a limited customer population.

c) No. Once a TUG project has been selected through SCE's risk-informed planning process, secondary facilities are evaluated during the planning and engineering phases as part of final project design. If secondary lines are determined to be feasible for inclusion, SCE does not perform a separate BCR calculation for secondary facilities added as part of a TUG project. The regional cost-

per-mile assumptions used in the initial BCR evaluation are developed from historical undergrounding projects and therefore should inherently reflect the approximate expected costs associated with both primary and secondary undergrounding work. As previously stated, secondary line wildfire risk is not explicitly included within SCE's TUG BCR methodology. Costs associated with secondary facilities that are incorporated into approved TUG projects are reflected in overall project execution costs, and are ultimately captured through SCE's accountability and reporting processes

Southern California Edison
A.26-05-018 – SCE 2026 RAMP

DATA REQUEST SET M G R A - S C E - V e r b a l - 0 0 1

To: MGRA
Prepared by: Bryan Landry
Job Title: Senior Advisor, Enterprise Risk Management
Received Date: 8/27/2026

Response Date: 8/31/2026

Question 01-03:
1. Were the Eaton and Palisades fires included in the fitted plot in SCE's Power Law whitepaper?
2. Did SCE use an 8 or 24 hour burn in the fitted plot in SCE's Power Law whitepaper?
3. Can SCE provide specific page references to the Taleb citations from the Power Law whitepaper?

Response to Question 01-03:

1) No. Instead, the natural unit consequences resulting from the Eaton and Palisades fires (e.g., acres burned, structures destroyed) were overlaid on the system-level WIM distributions in order to compare the resulting system-level WIM model against the modeled distributions.
2) SCE used the FireSight 8 24-hour simulation data for this scaled hybrid model.
3) Relevant discussions of Taleb (2022) can be found in Taleb, N. N. (2019). *Statistical Consequences of Fat Tails: Real World Preasymptotics, Epistemology, and Applications* (Technical Incerto Collection PDF ed.), pp. 99 106, 111 121, 132 144, 175 184.

2026 RAMP
SCE
MGRA Data Request No. 4
August 25, 2026

MGRA-4-1 In Data Request Response SPD-SCE-2026RAMP-04 Q26, SCE provided a list of 2,323 FIPA events.

a. Geospatial analysis finds that only 19 of the FIPA events are within the HFRA. Does SCE concur with this analysis and if so how does it explain the fact that so few FIPA events are within the HFRA?

b. Among FIPA causes, Weather/Contamination is listed as a major cause of FIPA ignitions from 2022 to February 2024. After that date, Weather/Contamination is not used as a cause classification. Instead, the "Tracking" classification appears.

a) Are "Weather/Contamination" and "Tracking" different classifiers for the same kind of event cause?

b) What are the definitions for "Weather/Contamination" and "Tracking"?

MGRA-4-2 In SCE Chapter 4 Workpapers, SCE presents the result of a sensitivity analysis in which it compares requested grid hardening miles with and without risk scaling. CC miles increase from 501 to 505 miles and UG miles increase from 201 to 211 miles when risk scaling is applied.

a. Why is the explanation for such a small increase in requested hardening miles when a risk averse scaling function is applied compared to the much larger increases seen in the SDG&E and PG&E analysis?

MGRA-4-3 At Chapter 4, p. 44, SCE states that in its proposal 236 miles of HFRA will remain unhardened.

a. Based on SCE's Technosylva wildfire simulations to date, how many of the 236 miles that it proposes to leave unhardened can result in wildfires of over 10,000 acres?

MGRA-4-4 Has SCE identified any ignitions due to tree fall-in in 2024, 2025, and 2026? If yes,

a. Provide the ignition ID and date of each ignition.

b. Identify if these were installed on the circuit experiencing the ignition:

a) REFCL

b) DOPD

c. Identify which were active for each ignition:

a) REFCL

b) DOPD

d. Provide details as to cause for each ignition.

MGRA-4-5 With regard to SCE Data request response SPD-SCE-2026RAMP-010, Q24.a, SCE states that:
"*Accordingly, the decision to underground a secondary line is not based on a separate risk-benefit determination for the secondary facility itself, but rather on whether the secondary line is associated with an approved TUG project and can be feasibly included within the final project design*."
When TUG projects are selected, they are screened for BCR as one of the conditions for inclusion. However, if a secondary line is subsequently added to the scope of the project, costs will be increased, while additionally there is a potential reduction of wildfire potential.

a. What fraction of a TUG project would undergrounding of secondary lines typically represent?

b. Does SCE recalculate a BCR for the joint primary and secondary TUG project once feasibility is finalized to ensure that addition of the secondary lines has not degraded the BCR?

MGRA-4-6 With regard to SCE Data Request Response SPD-SCE-2026RAMP-004, Q. 53, SCE reports the number of FCS faults in 2023, 2024, and 2025 showing that there were significantly more FCS faults in 2025 than in the other years.

a. Provide the number of hours that FCS settings were active in 2023, 2024, and 2025.

b. Was the increase seen in 2025 due to a larger number of hours spent with FCS settings on or due to a reduction in the threshold for FCS activation?

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company Regarding 2026 Risk Assessment Mitigation Phase. (U 338-E)	Application No. 26-05-018 (Filed May 15, 2026)

INFORMAL COMMENTS OF SMALL BUSINESS UTILITY ADVOCATES ON THE SOUTHERN CALIFORNIA EDISON 2026 RISK ASSESSMENT AND MITIGATION PHASE APPLICATION

Luke May
Regulatory Attorney
E&E Law Corp.
One Sansome Street, Suite 1400
San Francisco, CA 94104
T: (503) 702-3655
E: luke@utilityadvocates.org

Counsel for **Small Business Utility Advocates**

September 4, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company Regarding 2026 Risk Assessment Mitigation Phase. (U 338-E)	Application No. 26-05-018 (Filed May 15, 2026)

INFORMAL COMMENTS OF SMALL BUSINESS UTILITY ADVOCATES ON THE SOUTHERN CALIFORNIA EDISON 2026 RISK ASSESSMENT MITIGATION PHASE APPLICATION

I. INTRODUCTION

Pursuant to the ALJ's Scoping Memo filed August 6, 2026, Small Business Utility Advocates (SBUA) submits the following Informal Comments to the California Public Utilities Commission Safety Policy Division (SPD), in relation to the Southern California Edison (SCE) Risk Assessment Mitigation Phase (RAMP) Application.

II. SCE SHOULD SEPARATELY EVALUATE IMPACTS FROM SMALL-BUSINESS OUTAGES RESULTING FROM PSPS EVENTS.

SCE appears to assign a single aggregate non-residential Customer Minutes Interrupted (CMI) outage value (approximately $41.62 per CMI) to all non-residential (*i.e.*, commercial) customers. [1] The record does not disaggregate that value or otherwise disclose differing outage costs attributable to small, medium, and large non-residential customers; nor does the Application itself clearly explain whether, and how, the $41.62 per CMI figure reflects a weighted average of outage costs across these commercial customer subcategories. This valuation stands in stark contrast to the $0.09 CMI assigned to residential customers, and in

[1] SCE RAMP Application, Ch. 2 at 6.

contrast to the "blended" rate of $5.63.[2] Notably, the $41.62 per CMI estimate of cost per minute interrupted for commercial customers is over four-hundred times the value assigned to residential customers.

Oversized cost impacts of interrupted service to large commercial and industrial customers could skew estimates such that the modeled Benefit-Cost Ratio (BCR) is artificially inflated. An inaccurate BCR, in turn, would negatively impact small business customers if they are assessed costs to fund mitigation projects without receiving commensurate benefits.

SBUA requests that SPD examine whether the value of $41.62 per CMI assigned to *all* commercial (*i.e.*, non-residential) customers is truly representative of impacts to small business customers, or that the estimate of $41.62 per CMI is the proper result of a quantitatively proportional weighted average. While SCE indicates that it has weighted risks between customer classes for different geographic regions,[3] the "non-residential" category ostensibly still combines small businesses with medium-, large-, and industrial-customers.

SPD previously identified this concern in its 2025 Sempra RAMP Report. In that proceeding, SDG&E separated CMI costs between Small Commercial & Industrial (C&I) customers from those for Medium and Large C&I customers. SDG&E reported CMI values of $7.81 for small business customers, and $188.38 for medium and large C&I customers.[4] However, SDG&E applied a flat value per CMI to represent electric reliability valuation for all customer classes; SPD found that applying a "single value overlooks important differences in how outages affect residential versus non-residential customers," and that "over-aggregation"

[2] *Id.*

[3] *Id.*

[4] SPD Evaluation Report on SEMPRA 2025 RAMP at 120-22; 145.

can increase costs and "distort CBR results."[5] Here, SCE's use of one single non-residential value poses the same aggregation problem.

As such, SPD should evaluate and require separate outage values for residential, small-, medium-, large-commercial, and industrial customers.[6] After recalculating material mitigation BCRs using a more refined customer-segment composition of each circuit, SCE should also disclose whether this customer-class disaggregation results in any changes to project rankings.

III. POTENTIALLY EFFECTIVE PSPS RESILIENCE RESOURCES APPEAR CATEGORICALLY UNAVAILABLE TO SMALL BUSINESS CUSTOMERS.

The criteria to qualify for SCE's "Fully Subsidized Permanent Battery Storage pilot," which – from a customer support perspective – is likely one of the more effective Public Safety Power Shutoffs (PSPS) assistance options, ostensibly categorically precludes participation by small business customers. SCE indicates that the Fully Subsidized Permanent Battery Storage offering is only offered to customers that have experienced at least five Public Safety Power Shutoff (PSPS) events, use multiple medical devices, and participate in CARE or FERA.[7] Those requirements effectively exclude ordinary small business customers. While SBUA acknowledges that SCE admits that this specific offering is intended to be "very limited," it is unclear to SBUA which specific types of PSPS resources are readily available and would actually be adopted by a notable share of small business customers – or whether there are any PSPS resources that would be tailored to small business customer needs.

---

[5] *Id.* at 121 (finding that "SDG&E uses a flat $3.67 per CMI to represent the electric reliability valuation for all customer classes, while actual values vary significantly by customer type ($188 for large C&I vs. $0.05 for residential). A single value overlooks important differences in how outages affect residential versus non-residential customers and does not account for higher-risk and lower-risk regions. This over-aggregation can increase residential reliability costs and distort CBR results.").

[6] *See Id.* (note that – in the SEMPRA RAMP Proceeding – SPD identified a related aggregation concern in the Sempra RAMP).

[7] ESJ White Paper at 18.

SCE does not explicitly explain which PSPS resilience assistance is available to small business customers, how many small businesses could participate, or whether those PSPS resources would effectively address outage-related needs. SPD should evaluate meaningful backup-power assistance available to ordinary small business customers, including available power capacity; small business historical participation in the Self-Generation Incentive Program (SGIP) (or any other relevant PSPS resource); whether funding is sufficient to support robust small business customer participation; prior marketing efforts toward small business customers; and whether small business customers funding these programs actually receive comparable resilience benefits to residential and large-load customers. Furthermore, SPD should evaluate what efforts, if any, SCE has made toward addressing PSPS needs of specific sub-categories of small business customers, including restaurants, retailers, professional offices, and other small businesses facing economic losses through spoiled inventory or closure. As such, SPD should require a disclosure and analysis of PSPS resource eligibility, participation, expenditures, capacity, and duration, by customer class; only by such disclosure can SPD determine whether small business customers will receive commensurate resilience benefits.

Lastly, if SCE develops specific PSPS resource offerings that categorically preclude small business customers from participating, then SCE should also develop a standalone small business PSPS resource program. Small business customers contribute to the ratepayer base, and small business customers should not be ignored at the expense of residential and large commercial customers.

IV. RISK AND RISK MITIGATION IN DISADVANTAGED & VULNERABLE COMMUNITIES IS NOT PROPERLY EXPLAINED.

SCE reports that Disadvantaged & Vulnerable Communities (DVCs) proportionate share of wildfire risk is expected to *increase* from 9% (before mitigation) to 10% (after mitigation),

while their PSPS-risk share remains constant at 14%.[8] Furthermore, nominal monetized DVC wildfire risk also increases during the RAMP mitigation timeframe – from approximately $639 million to $675 million. This is particularly notable, given that systemwide wildfire risk declines.[9]

While SCE states that inflation may cause post-mitigation risk to appear higher, this could only explain the increase in the nominal monetized dollar value associated with total risk. If inflation is applied comparably across DVC and non-DVC consequences, then it should not materially change their relative shares; inflation simply cannot explain why the *proportional share* of total risk increases in Disadvantaged & Vulnerable Communities.[10] The increased share raises a material question as to why SCE's portfolio produces proportionally less wildfire-risk reduction in Disadvantaged & Vulnerable Communities. SPD should require clear reporting on investment dollars, completed work, and risk reduction per dollar in DVC and non-DVC areas, and evaluate reasons why disadvantaged communities will not reap equitable and commensurate risk-reduction benefits.

Small business customers located in DVCs are necessarily part of the population bearing this disproportionate residual wildfire and PSPS risks. Accordingly, SCE's DVC analysis should specifically evaluate whether small businesses in these communities receive equitable risk-

[8] ESJ White Paper at 11.

[9] *See* SCE RAMP Application, Ch. 4 at 76, Table VII-32 (providing that systemwide wildfire risk gradually declines from approximately $6.981 billion (before mitigation, 2029) to $6.718 billion (after mitigation, 2032)).

[10] *Id.*

reduction benefits from the proposed mitigation portfolio, consistent with the Commission's direction to consider impacts on "small businesses in ESJ communities."[11]

V. SPD SHOULD CLOSELY EXAMINE HIGH-COST PROGRAMS THAT ARE ASSOCIATED WITH LOW REPORTED BCRS.

SPD should evaluate high-cost programs with low reported Benefit-Cost Ratios. While SBUA agrees that a low BCR does not categorically suggest that a safety mitigation option should be rejected, high-cost programs with low BCRs require stricter substantiation – including an analysis separating legally mandatory minimum scope activities from discretionary or enhanced scope activities; whether lower-cost alternatives exist; and whether deploying a high-cost and low-BCR mitigation action could effectively supplant other lower-cost actions that would yield greater risk reductions; and whether there are notable non-quantifiable benefits that may not be captured in the BCR methodology. SBUA recommends that SPD evaluate the following specific areas:

- Employee Safety proposed plan: This proposed mitigation forecasts costs of $332.4 million, but is only estimated to result in a (hybrid) BCR of 0.34.[12] Within the Employee Safety plan, High Hazard Field Safety Training alone is estimated to cost approximately $211.8 million, but yields a BCR of only 0.02.[13]
- Public Safety Locate and Mark–Distribution: This proposed mitigation forecasts costs of approximately $147.7 million, but is only estimated to yield a BCR of 0.49.[14]
- Physical Security proposed plan: This proposed mitigation forecasts costs of approximately $501.5 million, but is only estimated to yield a BCR of 0.15.[15]

[11] Environmental and Social Justice (ESJ) Action Plan 2.0, Goal 1.1.1, directs that the Commission consider ESJ impacts on "small businesses in ESJ communities" when developing new processes.

[12] SCE RAMP Application, Ch. 7 at 39, Tables VII-11, VII-12, and VII-14.

[13] SCE RAMP Application, Ch. 7 at 42, Table VII-14 (BCR Values for Proposed Plan Controls).

[14] SCE RAMP Application, Ch. 9 at 30.

[15] SCE RAMP Application, Ch. 12 at 44-45, Tables VII-8; VII-9, and VII-10.

A further evaluation of these factors would better satisfy Scoping Issue Number 1(a), relating to whether SCE "identifies and integrates the full set of benefits that are the result of the incurred costs into its benefit cost ratio (BCR) estimates," and whether SCE has demonstrated an "adequate consideration of these costs and benefits."[16] In sum, for programs with low BCRs, SCE should better explain why its proposal is justified.

VI. SPD SHOULD REQUIRE THAT SCE SEPARATE REAL RISK REDUCTION FROM INFLATION NOISE AND REQUIRE A "NO-PROGRAM" COUNTERFACTUAL.

SCE's Application provides that the nominal monetized risk score, *after* mitigation, will increase for certain categories. These include:

- Employee Safety: approximately $52.839 million to $57.870 million.[17]
- Contractor Safety: approximately $84.233 million to $92.254 million.[18]
- Public Safety: approximately $275.963 million to $294.476 million.[19]
- Physical Security: approximately $159.810 million to $165.971 million.[20]

As noted, *supra* Section IV, SCE asserts that some nominal dollar risk increases may be explained by inflation, persistent exposure, and changes in risk conditions.[21] These nominal values obscure the actual risk-reduction value associated with SCE's proposed mitigation expenditures. As such, SPD should require further explanation for each risk identified above – including the pre- and post-RAMP risk in a static and comparable metric (*e.g.*, fixed 2026 dollars); a counterfactual scenario providing the nominal value of risk expected in 2032 without

[16] Scoping Memo at 2, Issue 1(a).

[17] SCE RAMP Application, Ch. 7 at 2; 38-41.

[18] SCE RAMP Application, Ch. 8 at 2; 33-37.

[19] SCE RAMP Application, Ch. 9 at 5; 29–31.

[20] SCE RAMP Application, Ch. 12 at 4; 43–45.

[21] *See e.g.*, SCE RAMP Application, Ch. 4 at 22, Footnote 41.

applying mitigation options to the risk areas identified above; and the net residual risk after mitigation, compared to a "no action" counterfactual. This additional comparison would better satisfy Issue 1(e) from the ALJ's Scoping Memo.[22]

VII. SCE DOES NOT CLEARLY ESTABLISH A SEGMENT-TO-TRANCHE RISK REPORTING UNIT "CROSSWALK" FOR CERTAIN RISK ASSESSMENTS.

SCE indicates that its Wildfire Integrated Model (WIM) utilizes detailed asset and location-level information; however, the model selects mitigations at the circuit level. Stated alternatively, while SCE's WIM is capable of assessing wildfire risk at a "granular, asset-level resolution" (which serves as a basis to identify high-risk segments), the model nevertheless selects mitigation actions at the circuit (*i.e.*, aggregated) level.[23] (*See* SCE RAMP, Ch. 4 at 38, noting that the wildfire Risk Reporting Unit (RRU) is defined as *all* High Fire Risk Area (HFRA) portions of a *circuit*).[24] Since SCE's model is capable of assessing risk at the "asset-level," SCE should provide an auditable crosswalk showing how granular inputs produced circuit-level decisions.

If SCE aggregates HFRA portions of a circuit into a single RRU and selects among certain grid-hardening mitigations using a circuit-level BCR framework, then the record should be further developed to evaluate how each segment's risk tranche appropriately corresponds to proposed mitigation actions (*e.g.*, covered conductor, undergrounding, Rapid Earth Fault Current Limiter (REFCL), or no selected mitigation action). SPD should require that SCE provide further

[22] Scoping Memo at 3, Issue 1(e) ("Whether SCE incorporates overall residual risk reporting in compliance with the directives of D.25-08-032.").

[23] SCE RAMP Application, Ch. 4 at 18-19.

[24] SCE RAMP Application, Ch. 4 at 38 ("Consistent with Commission guidance, SCE defined the Risk Reporting Unit (RRU) for wildfire risk as all the portions of a given circuit within SCE HFRA.) (*See also* PubAdv-SCE-2026-RAMP-AYN01, Q.1, Response at 1, noting that "SCE first applied a circuit-level benefit-cost framework" comparing Covered Conductor, Targeted Undergrounding, and Covered Conductor paired with Rapid Earth Fault Current Limiter (REFCL) as selectable mitigation options.).

narrative and quantitative explanation, such that each segment's risk, tranche, circuit RRU, cost, selected mitigation, risk reduction, and BCR is clearly mapped. This additional analysis is necessary to better determine whether certain lower-risk circuit completion work may leave higher-risk segments untreated, which is fundamentally necessary for parties to evaluate SCE's filing for prudence.

VIII. CONCLUSION

SBUA respectfully requests that SPD require the analyses, corrections, and disclosures identified *supra* Sections II-VII. Greater transparency is necessary for meaningful review; SPD should require further record development relating to: outage cost valuation; PSPS resource availability to small business customers; disproportionately low risk mitigation reductions to Disadvantaged & Vulnerable Communities; high-cost and low Benefit-Cost Ratio programs; impacts of inflation on nominal costs of proposed programs; and wildfire risk aggregation & mitigation selection. These measures will help ensure that SCE's proposed investments target the greatest risks, provide measurable benefits, and do not impose costs on small-business ratepayers without receiving commensurate safety and reliability benefits.

Dated: September 4, 2026

Respectfully Submitted,

By: /s/ Luke May

Regulatory Attorney
E&E Law Corp.
One Sansome Street, Suite 1400
San Francisco, CA 94104
Counsel for Small Business Utility Advocates

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) Regarding 2026 Risk Assessment Mitigation Phase.	Application 26-05-018 (Filed May 15, 2026)

INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK

Hayley Goodson
Managing Attorney
Email: hayley@turn.org

Thomas Long
Outside Counsel
Email: tomjlong@sbcglobal.net

THE UTILITY REFORM NETWORK
360 Grand Avenue, #150
Oakland, CA 94610
Phone: (415) 929-8876

September 4, 2026

TABLE OF CONTENTS

1. SUMMARY OF TURN'S RECOMMENDATIONS 1

2. TURN'S ANALYSIS OF SCE'S PRESENTATION OF OPTIMIZED PORTFOLIOS 3

2.1 Overview of Applicable RDF Requirements 3

2.2 SCE's Presentation of Optimized Portfolios 6

2.3 Assessment of SCE's Approach 10

2.4 Recommendations for the GRC 12

3. SCE'S MITIGATION GROUPING FRAMEWORK 14

3.1 RDF Requirements 14

3.2 SCE's Methodology 15

3.3 Assessment of SCE's Methodology 16

3.4 Recommendations for the GRC 17

4. CONCLUSION 17

INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK

In accordance with the August 6, 2026 Scoping Ruling, The Utility Reform Network (TURN) submits these Informal Comments on the Risk Assessment Mitigation Phase (RAMP) submission of Southern California Edison Company (SCE). TURN's comments are limited to SCE's presentation regarding the new Risk-Informed Decision-making Framework (RDF) requirement adopted in Decision (D.) 25-08-032 to present budget-constrained optimized portfolios of mitigations for four prescribed budget scenarios. In these comments, TURN refers to this as the Budget-Constrained Optimization (BCO) requirement.

1. SUMMARY OF TURN'S RECOMMENDATIONS

Analysis of SCE's Presentation of Optimized Portfolios. SCE presented two sets of optimized portfolios under the four required Budget Scenarios– an Optimized *Enterprise* Portfolio and an optional set of Optimized *Risk-Specific* Portfolios. In presenting its preferred optional Risk-Specific portfolios, SCE did not sufficiently justify the different and less cost-effective allocation of costs to risks than would occur under the Optimized Enterprise Portfolio, as required by RDF Rule 25.2. For example, SCE did not explain why it would elect to spend less than optimal amounts on Wildfire mitigations to enable increased funding for less cost-effective mitigations for the PSPS, Employee Safety, and Physical Security risks. While SCE may have a good justification for its preferred allocation of resources among risks, it is not provided. SCE should correct this shortcoming in its GRC submission to improve the usefulness of the new BCO requirement as a tool to help decisionmakers decide which activities are most deserving of funding. Specifically, SCE should do the following in its GRC:

- If SCE chooses to present alternative Optimized Risk-Specific Portfolios under Row 25.2 as its preferred optimized portfolios, it must justify and explain, for each sub-100% budget scenario, why it proposes to allocate costs among risks differently and less cost-effectively than the Row 25.1 Optimized Enterprise Portfolio. For each budget scenario, SCE should identify and explain, for each risk in which SCE proposes a materially different allocation of costs compared to the Row 25.1 portfolio, all non-BCR factors that SCE believes make its less cost-effective recommendation the superior proposal.

Interrelationships Among Mitigations and Controls. A key element of the new BCO requirement is that the activities that are being optimized in the portfolios must take into account the interrelationships among mitigations and controls, such as mutual exclusivity, synergies and diminishing returns. SCE provided an explanation of its methodology for complying with that requirement in one of its Chapter 2 PDF workpapers.[1] TURN was unable to conduct a full analysis of SCE's methodology and calculations to implement that methodology. However, TURN's limited analysis identified room for improvement to SCE's Mitigation Grouping Framework in two respects. SCE's GRC should correct the following problems:

- SCE should include compliance activities in its Mitigation Grouping Framework, as required by the RDF.

- In its Excel workpaper documenting its optimized portfolios,[2] for each row identifying a grouped set of activities, SCE should list the activities in the priority order that SCE claims to have used to account for interrelationships among mitigations.

[1] Chapter 2 PDF Workpaper: Risk Model and BRC Methodology, Mitigation Grouping and BCR Calculation (Mitigation Grouping workpaper).

[2] Chapter 2 Excel Workpaper: SCE 2026 RAMP Optimization.

2. TURN'S ANALYSIS OF SCE'S PRESENTATION OF OPTIMIZED PORTFOLIOS

2.1 Overview of Applicable RDF Requirements

The revised RDF adopted in D.25-08-032 requires Optimized Portfolios at each of four Budget Scenarios.[3] The term "Optimized (Enterprise or Risk Mitigation) Portfolio" is defined as follows:

> A portfolio that is optimized using an optimization model where the objective to be maximized is risk reduction, the constraint is a given budget level in dollars, and the decision variable (i.e., what is selected by the optimization algorithm to maximize the objective function) is whether a given mitigation is included in the portfolio or not.[4]

In other words, an optimized portfolio is one that provides the maximum risk reduction for the given level of spending.

The RDF specifies four Budget Scenarios for the optimized portfolios, 85%, 90%, 95% and 100% of the "Baseline Cost Forecast."[5] The Baseline Cost Forecast is defined as "[a]n estimate of the expenditures for all RAMP-related Mitigation and Control Programs for which an IOU is seeking approval and/or funding in its RAMP or current GRC application."[6]

Row 25.1 of the RDF requires an Optimized *Enterprise* Portfolio under each of the four budget scenarios. "Enterprise Portfolio" is defined as a "collection of activities within a specified Budget Scenario reflecting all of the RAMP-related Mitigation and Control Programs

[3] RDF, Rows 25.1 and 25.2.

[4] RDF, page A-6. In these comments all references to the RDF are to the RDF adopted in D.25-08-032, which is Appendix A to that decision.

[5] RDF, Row 25.1

[6] RDF, p. A-3.

to be funded in the utility's General Rate Case."[7] Optimized Enterprise Portfolios thus reflect the most cost-effective activities to address the full set of RAMP risks within the constraint of an overall budget covering all of those risks.

Row 25.2 of the RDF allows the utility to construct Optimized Risk Mitigation Portfolios specific to each risk "based on a different allocation of costs among risks than would occur under the corresponding Optimized Enterprise Portfolio."[8] In other words, the utility can specify an amount it wishes to spend for each risk that is different from the per risk spending amounts that resulted under the Optimized Enterprise Portfolio, thus imposing an additional risk-by-risk budget constraint. Row 25.2 recognizes that, while Enterprise-level optimized portfolios provide important information, the utility may have good reasons for altering the allocation of resources among risks that Enterprise-level optimization would prescribe. By definition, these risk-specific optimized portfolios would not be optimal compared to the Optimized Enterprise Portfolios, in that they will be less cost-effective and achieve less risk reduction at each sub-100% budget level than a portfolio that maximizes risk reduction at the enterprise level. For this reason, Row 25.2 requires the utility to "justify" the proportion of resources devoted to each risk.[9]

---

[7] RDD, p. A-4. The definition further states that "[t]he Enterprise Portfolio will include a Risk Mitigation Portfolio for every Enterprise Risk presented in a RAMP."

[8] Row 26 of the RDF states that "the utility must present the set of Optimized Enterprise Portfolios required by Row 25.1 and may present an alternative set of Optimized Risk Mitigation Portfolios within each Enterprise Portfolio in accordance with Row 25.2." This sentence recognizes that the alternative set of Optimized Risk Mitigation Portfolios allowed under Row 25.2 combine to create a different Enterprise Portfolio than the Optimized Enterprise Portfolio required under Row 25.1.

[9] The role of Row 25.2 risk-specific optimized portfolios is discussed in on pages 4 to 5 of TURN's Opening Comments in R.20-07-013 (dated 8/14/25) on the proposed decision (PD) that

Row 26 imposes additional requirements to identify and justify the utility's preferred portfolios. In both the RAMP and GRC, Row 26 requires the utility to identify its "proposed Enterprise Portfolio," which could be either the Row 25.1 Optimized Enterprise Portfolio or, if the utility so elects, the combined set of optimized risk-specific portfolios to address each RAMP risk.[10] Row 26 states that "[t]he utility must explain how the budget scenario and other constraints factored into the utility's portfolio selection," which means that the utility must indicate its proposed portfolio and provide this explanation *for each budget scenario*. In addition, Row 26 requires the utility to explain whether and how factors other than Benefit-Cost Ratios (BCR) affected its choice of activities to include in its chosen portfolio under the various budget scenarios.[11]

---

was revised to become D.25-08-032. Virtually all of TURN's recommended changes to Rows 25.1, 25.2 and 26 in the PD were adopted verbatim in the final decision.

[10] RDF, Row 26, using the term "proposed Enterprise Portfolio" twice in the fifth paragraph. As noted in footnote 8, the utility's proposed Enterprise Portfolio could be based on either the required Row 25.1 Optimized Enterprise Portfolio, or the entire set of risk-specific optimized portfolios allowed under Row 25.2.

[11] Specifically, the fifth paragraph of Row 26 states: "The utility's proposed Enterprise Portfolio, including its Mitigation and Control Programs selection, Risk Reporting Unit prioritization, and Risk Mitigation Portfolio optimization can be influenced by Benefit-Cost Ratios and other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In the RAMP and GRC, the utility will explain whether and how any such factors affected the utility's proposed Enterprise Portfolio, including its Mitigation and Control Program selections and Risk Reporting Unit prioritization.

2.2 SCE's Presentation of Optimized Portfolios

In an Excel workpaper,[12] SCE presented Row 25.1 Optimized Enterprise Portfolios under each budget scenario. SCE also elected to provide alternative Row 25.2 Optimized Risk Mitigation Portfolios.

For both types of optimization, SCE followed the same basic approach. First, SCE identified what it deemed to be compliance activities, meaning activities SCE viewed as "must-take." The activities and associated funding estimates for these compliance activities were included in all optimized scenarios. Second, for the remaining non-compliance activities, SCE ranked them by BCR and selected them sequentially for inclusion in the portfolio until the applicable total company budget constraint was reached. For the Row 25.1 Optimized Enterprise Portfolios, this meant that SCE ranked by BCR all of the over 11,000 activities that made up its Baseline Cost Forecast and then selected the highest-BCR activities until the given budget scenario limit was reached.

For its alternative Row 25.2 risk-specific optimized portfolios, SCE specified spending amounts for each risk and applied the specific budget scenarios (85%, 90% etc.) to these risk-specific budgets, again following the same sequential activity selection process until the risk-specific budget was exhausted.[13] SCE stated that this was its "preferred approach," using "BCRs

[12] Chapter 2 Excel Workpaper: SCE 2026 RAMP Optimization.

[13] In discovery, SCE explained that, if the cost of the next available mitigation or mitigation tranche in the ranking would cause the budget limit to be exceeded, that activity would not be included. The result was that for certain mitigations, spending was less than the full-budget-constrained amount. SCE Response to DR TURN-SCE-001, Question 4(b). This is reflected in Table 1 below, which shows that the Total NPV Spend is lower under the Risk-Specific Optimization compared to the Enterprise Optimization.

as an input to decision-making within the context of ***risk-specific*** mitigation strategies, rather than a strict rank-ordering at the enterprise level."[14]

The spending results of SCE's two optimization approaches are shown in Table 1 below. The spending amounts reflect SCE's estimated costs of the specific activities that are included in each optimized portfolio. Those activities and costs are detailed in SCE's Excel workpaper. While there are differences in the included activities and the resulting allocation of costs among risks between the enterprise-level (Row 25.1) and risk-specific (Row 25.2) optimizations for all sub-100% budget scenarios, the differences are most pronounced under the 85% budget scenario. Under that scenario, the Risk-Specific Optimization alternative would spend significantly less on the Wildfire, Overhead Equipment Failure, Cyber and Seismic risks and significantly more on the Employee Safety, PSPS, Hydro, Physical Security and Underground Equipment Failure risks, compared to the Optimized Enterprise Portfolio.

[14] SCE RAMP Report, Chapter 2, p. 30 (emphasis in original).

Table 1: SCE's NPV Spend ($M) Under Budget Scenarios

Risk	Enterprise Optimization				Risk-Specific Optimization[15]			
	85%	90%	95%	100%	85%	90%	95%	100%
Cyber	600	600	600	600	487	487	544	600
Seismic	162	162	162	162	115	115	115	162
Contractor Safety	11	15	15	15	11	11	11	15
Wildfire	3,653	3,663	3,666	3,666	3,098	3,294	3,480	3,666
Overhead Equipment Failure	2,702	2,806	2,926	2,957	2,513	2,659	2,809	2,957
Underground Equipment Failure	1,317	1,431	1,538	1,723	1,465	1,551	1,637	1,723
Public Safety	14	112	112	112	14	14	14	112
Employee Safety	26	65	81	223	153	153	153	223
PSPS	11	27	76	123	102	108	117	123
Hydro	7	7	43	84	67	75	78	84
Physical Security	1	47	286	339	288	302	321	339
Total NPV Spend	**8,502**	**8,934**	**9,504**	**10,004**	**8,312**	**8,770**	**9,277**	**10,004**
Overall BCR	**6.93**	**6.61**	**6.23**	**5.92**	**6.79*[16]**	**6.53***	**6.18***	**5.92**

[15] Risk-Specific Optimization spending figures were provided by SCE in response to Data Request TURN-SCE-001, Question 3. As explained in footnote 13 above, the reason for the Total NPV Spend disparity between comparable budgets in the Enterprise and Risk-Specific Optimizations is apparently SCE's practice of not including the next available mitigation or mitigation tranche in the ranking if its cost would cause the budget limit to be exceeded.

[16] The asterisks denote adjusted BCR values. To make the Optimized Risk-Specific Portfolio BCRs an apples-to-apples comparison with the Optimized Enterprise Portfolio BCRs, the Risk-Specific BCRs were adjusted to use the same total spending amounts as the Enterprise portfolios at each of the sub-100% budget levels. TURN imputed the incremental NPV benefits associated with the incremental spend amounts to equal the Enterprise total spend based on the BCR of the activity with the lowest BCR at each budget level in the Optimized Enterprise Portfolio. These BCR values were 0.5 for the 85% scenario, 0.2 for the 90% scenario, and 0.1 for the 95% scenario.

SCE's preferred risk-specific portfolios would fund certain activities that are clearly less cost-effective than the more cost-effective activities they would supplant, as shown by the data in Tables 2 and 3 below.

Table 2: BCR of Marginal Activities that Would Not Be Funded in Risk-Specific Optimized Portfolio (85% Scenario)

Risk	BCR of Marginal Unfunded Activity
Wildfire	2.11
Cyber	2.01
Seismic	1.48
Overhead Electric Failure	1.15

Table 3: Average BCR for Entire Risk-Specific Portfolio

Risk	Average Portfolio BCR
Employee Safety	0.49
PSPS	0.28
Hydro	0.08
Physical Security	0.18

To give an idea of the BCRs of the activities that SCE's preferred portfolio would choose not to fund, Table 2 identifies the BCR of the marginal, i.e., next-in-rank, unfunded activity in SCE's risk-specific optimized portfolio for the given risks.[17] Those BCRs significantly exceed the average portfolio BCR of the funded activities for each of the risks shown in Table 3. The upshot is that, for the 85% budget scenario, SCE's preferred portfolios would fund many activities that are much less cost-effective than many of the unfunded activities for the risks

[17] For the Seismic risk, the BCR shown is for the only unfunded activity. For the Cyber risk, the only other unfunded activity had a BCR of 1.90. For each of the Wildfire and Overhead Equipment Failure risks, there were numerous unfunded activities that exceeded all of the portfolio BCRs in Table 3.

shown in Table 2. This is an illustration of the unsurprising result that an optimized *enterprise-level* portfolio is more cost-effective than a set of risk-specific optimized portfolios.

SCE may have good reasons for choosing an allocation of costs among risks that results in funding less cost-effective mitigations at the expense of other more cost-effective activities, but SCE needs to justify its preferences, as required by Rows 25.2 and 26.

2.3 Assessment of SCE's Approach

TURN does not disagree with SCE's optimization approach of using a ranking of activities by BCR to select the activities that will maximize risk reduction under each budget constraint. In fact, this approach was suggested by TURN in Track 4 of R.20-07-013.[18]

However, contrary to Row 25.1, SCE does not sufficiently justify its preferred allocation of resources among risks under its Row 25.2 risk-specific optimizations, compared to the more efficient Row 25.1 enterprise optimizations. Relatedly, contrary to Row 26, SCE does not explain how factors other than BCR affected SCE's proposed portfolio.

As Table 1 shows, SCE's alternative portfolios under Row 25.2 are based on a different allocation of costs among risks than would result under the required Rule 25.1 optimizations. For example, at the 85% budget level, SCE's Row 25.2 risk-specific alternative allocates 85% of Row 25.1 costs to the Wildfire risk, 111% of Row 25.1 costs to the Underground Electric Failure Risk, and 828% of Row 25.1 costs to the PSPS risk, among other differences. Put another way, compared to the Optimized Enterprise Portfolio, SCE's preferred set of risk-specific portfolios would spend less on mitigating the Wildfire risk (among others), and more on risks such as Underground Electric Failure and PSPS.

[18] D.25-08-032, pp. 37-38, discussing TURN's position.

As noted, Rule 25.2 requires SCE to justify, for each optimized risk-specific portfolio, why it allocated such a different proportion of costs compared to the corresponding Row 25.1 optimized portfolio. In discovery, SCE points to Chapter 2, Section P, Part 2, as supplying SCE's justification.[19] There, the only potentially relevant discussion is the following paragraph:

> This proportional allocation is appropriate given that the estimated spend for each RAMP risk has already undergone an initial review through SCE's internal business planning process, which considers feasibility, timing, overall costs, and relative prioritization across risks. As a result, and for RAMP purposes only, the estimates resulting from these budget-constrained scenarios reflect preliminary, risk-informed allocation of resources across the portfolio.[20]

This short paragraph is far too general and vague to provide a meaningful justification of SCE's preferred allocation of costs compared to the enterprise-level optimization. It does not provide any specific explanations of why, for example, SCE believed that, at budget-constrained spending levels, more cost-effective Wildfire and Cyber risk mitigation activities should be sacrificed to boost the amount of less cost-effective activities to address the Physical Security, PSPS, Employee and Hydro risks. Such explanations would be highly informative to parties and decisionmakers. A vague paragraph that only states that the activities and allocation of costs in the risk-specific optimized portfolios are based on the company's planning process does nothing to justify an allocation of costs and a portfolio of activities that is less cost-effective than the Optimized Enterprise Portfolio under each sub-100% budget scenario.

[19] SCE response to DR TURN-SCE-001, Question 6(c).

[20] SCE RAMP Report, Chapter 2, p. 35.

SCE also does not explain the non-BCR factors that cause it to prefer its Row 25.2 risk-specific portfolios under the various budget scenarios, as required by Row 26.[21] SCE omits such a discussion even though its RAMP report quotes the portion of Row 26 that recognizes that non-BCR factors can influence portfolio selection.[22] Rows 25.2 and 26 require SCE not just to state that it disagrees with basing portfolio selection on a ranking of activities by BCR but to present its preferred portfolios under each of the budget scenarios and to justify those less cost-effective scenarios by explaining the non-BCR factors that cause it to propose portfolios that result in less risk reduction at a given budget level.

2.4 Recommendations for the GRC

SCE can and must correct the above-described deficiencies in its GRC submission. Row 26 requires SCE's *GRC* showing to meet the Row 25.1 requirement and, if SCE chooses, to provide alternative optimized portfolios under Row 25.2, with the accompanying justification of its less cost-effective allocation of costs among risks.[23] As noted, Row 26 further requires SCE's

[21] The fifth paragraph of Row 26 states: "The utility's proposed Enterprise Portfolio, including its Mitigation and Control Programs selection, Risk Reporting Unit prioritization, and Risk Mitigation Portfolio optimization can be influenced by Benefit-Cost Ratios and other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In the RAMP and GRC, *the utility will explain whether and how any such factors affected the utility's proposed Enterprise Portfolio, including its Mitigation and Control Program selections and Risk Reporting Unit prioritization*." (Emphasis added).

[22] SCE RAMP Report, Chapter 2, pp. 29-30.

[23] As noted, Row 25.2 requires the utility to "justify why the proportion of the Enterprise Portfolio Budget Scenario was chosen for each Optimized Risk Mitigation Portfolio." The first paragraph of Row 26 states, in relevant part: "The utility's RAMP filing . . . must present the set of Optimized Enterprise Portfolios required by Row 25.1 and may present an alternative set of Optimized Risk Mitigation Portfolios within each Enterprise Portfolio in accordance with Row 25.2. Mitigation/Control Groups defined in Row 25.2 can also be ranked

GRC to explain how the different budget scenarios and any non-BCR factors affected SCE's portfolio selection.[24]

Accordingly, TURN urges SPD to include the following recommendation in its evaluation report of SCE's RAMP:

- If SCE chooses to present alternative Optimized Risk-Specific Portfolios under Row 25.2 as its preferred optimized portfolios, it must justify and explain, for each sub-100% budget scenario, why it proposes to allocate costs among risks differently and less cost-effectively than the Row 25.1 Optimized Enterprise Portfolio. For each budget scenario, SCE should identify and explain, for each risk in which SCE proposes a materially different allocation of costs compared to the Row 25.1 portfolio, all non-BCR factors that SCE believes make its less cost-effective recommendation the superior proposal.

within each portfolio. The utility must justify the portfolio selection, optimization, and structure of Mitigation/Control Groups." The second paragraph of Row 26 requires these RAMP showings to be updated in the GRC: "In the GRC, the utility will provide an updated presentation of the set of Optimized Enterprise Portfolios required by Row 25.1 and the optional set of Optimized Risk Mitigation Portfolios within each Enterprise Portfolio in accordance with Row 25.2 if an update is necessary. Any differences in these Optimized Portfolios from the RAMP filing must be clearly explained by the utility in its GRC filing."

[24] The fourth and fifth paragraphs of Row 26 state: "In the RAMP *and GRC*, the utility will clearly and transparently explain its rationale for selecting Mitigation and Control Programs for each enterprise risk presented in the RAMP and for its selection and optimization of its portfolio of Mitigation and Control Programs for each enterprise risk presented in the RAMP. *The utility must explain how the budget scenario and other constraints factored into the utility's portfolio selection.* In the RAMP *and GRC*, the utility will clearly and transparently explain its rationale for prioritizing Risk Reporting Units for each Mitigation and Control Program. [¶] The utility's proposed Enterprise Portfolio, including its Mitigation and Control Programs selection, Risk Reporting Unit prioritization, and Risk Mitigation Portfolio optimization can be influenced by Benefit-Cost Ratios and other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In the RAMP *and GRC*, *the utility will explain whether and how any such factors affected the utility's proposed Enterprise Portfolio, including its Mitigation and Control Program selections and Risk Reporting Unit prioritization*." (Emphasis added).

TURN would hope that SCE would view this recommendation as not just a compliance obligation, but as an opportunity to support its longstanding and repeated protestations that BCR rankings alone do not produce optimal portfolios.[25] If SCE elects to recommend portfolios that provide less than optimal risk reduction, it should provide specific explanations of each factor that led SCE to those conclusions.

3. SCE'S MITIGATION GROUPING FRAMEWORK

3.1 RDF Requirements

An important element of the new BCO requirement is that the activities that are being optimized in the portfolios must take into account the interrelationships among mitigations, as specified in Row 25.2 of the RDF:

> Mitigations and Controls in each Optimized Risk Mitigation Portfolio shall account for interrelationships between them, such as mutual exclusivity, synergies, and diminishing returns.
>
> Mutually exclusive Mitigations and Controls must be avoided, only one or the other can address the same asset or system that exhibits risk in the same portfolio.
>
> Synergies and diminishing returns can be captured by combining two or more mitigations to address risk on a given asset or system, called a Mitigation Group. Synergies or diminishing returns can be calculated for the Mitigation Group.
>
> For example, a wildfire mitigation portfolio could include for a given circuit segment: covered conductor as a mitigation, vegetation management as a mitigation, or covered conductor with vegetation management as a mitigation—but not covered conductor and vegetation management as separate mitigations since their benefits are not additive (re: may exhibit diminishing returns).

This requirement also applies to Optimized Enterprise Portfolios under Row 25.1.[26]

---

[25] See, e.g., SCE RAMP Report, Chapter 2, pp. 29-30.

[26] The third paragraph of Row 25.1 states: "Optimized Enterprise Portfolios shall account for the interrelationships among mitigations and controls, as described in Row 25.2."

D.25-08-032 describes the importance of accounting for interrelationships among mitigations in constructing optimized portfolios:

> . . . mitigations are often interrelated and may be synergistic, where they work together to decrease the amount of risk, or provide diminishing returns, in which mitigations together reduce risk but as investment in one increases, the need for the other mitigation is reduced. The solution that SPD staff proposes to evaluate interrelated mitigations is to construct portfolios of mitigations that can be compared and ranked.[27]

3.2 SCE's Methodology

SCE labels its effort to comply with the requirement to account for interrelationships among mitigations as its Mitigation Grouping Framework, which is described in a Chapter 2 PDF workpaper.[28] In that workpaper, SCE describes its methodology as follows:

> Under SCE's Mitigation Grouping Framework (MGF), interaction effects are addressed through interaction-adjusted risk reduction calculations, ensuring that the risk-reduction benefits of individual mitigations are credited only once when multiple mitigations are applied to the same asset/RRU/Tranche.
>
> In order to accomplish this, SCE processes mitigations within a specified mitigation grouping in a predefined priority order. This priority ordering is based on the whether the mitigation is durable; its relative mitigation effectiveness; as well as the mitigations effective useful life (EUL). This prioritization order was established through stakeholder review of the individual mitigations contained within each mitigation grouping.
>
> In practice, for a given asset, the mitigation effectiveness of the highest-priority mitigation within a Mitigation Group is first applied to reduce risk associated with the relevant risk drivers at that location. The resulting residual risk baseline then serves as the starting point for subsequent mitigations, which are applied sequentially with each reducing only the remaining available risk based on its mitigation

[27] D.25-08-032, p. 30.

[28] Chapter 2 PDF Workpaper: Risk Model and BRC Methodology, Mitigation Grouping and BCR Calculation (Mitigation Grouping workpaper).

effectiveness for the applicable risk drivers until all mitigations in the mitigation group have been applied.[29]

3.3 Assessment of SCE's Methodology

TURN's resource limitations for this case prevented a comprehensive review of SCE's methodology and its calculations to implement its approach. However, TURN did review the Excel spreadsheet in which SCE lists each of the over 11,000 activities that SCE included in its optimizations, a significant portion of which consist of two or more grouped mitigations pursuant to SCE's Mitigation Grouping Framework. Sometimes, SCE shows as many as 12 different grouped activities for one tranche of work.[30] In our limited analysis, TURN found two concerns.

First, SCE does not include compliance activities in its Mitigation Grouping Framework, as SCE admitted in response to a TURN data request.[31] Nothing in the RDF allows compliance activities to be removed in the process of accounting for interrelationships among activities. To the contrary, the above-quoted requirement applies expansively, to both mitigations and controls. In addition, the wildfire mitigation portfolio illustration that the RDF provides in Row 25.2 includes an activity that SCE treats as a compliance activity, vegetation management. Row 25.2 points out that covered conductor and vegetation management should be grouped because their benefits may exhibit diminishing returns. In discovery, SCE stated that it nevertheless elected to treat compliance activities separately because they are mandatory requirements.[32] However, this misses the point, reflected in Row 25.2 and admitted by SCE, that compliance and non-

[29] Mitigation Grouping Workpaper, p. WP-3.

[30] Chapter 2 Excel Workpaper: SCE 2026 RAMP Optimization.

[31] SCE response to DR TURN-SCE-002, question 1(c).

[32] SCE response to DR TURN-SCE-002, question 1(c).

compliance work can influence the other.[33] As recommended below, SCE should remedy this problem in its GRC.

Second, SCE's Excel workpaper showing the grouped activities does not list the activities in the priority order in which their mitigation effectiveness was applied,[34] even though this process is central to SCE's Mitigation Grouping Framework. Listing the activities in priority order would assist reviewers in assessing the reasonableness of SCE's efforts. This problem should be remedied in the GRC submission.

3.4 Recommendations for the GRC

TURN urges SPD to include the following recommendations in its evaluation report of SCE's RAMP:

- SCE should include compliance activities in its Mitigation Grouping Framework as required by the RDF.
- In its Excel workpaper documenting its optimized portfolios,[35] for each row identifying a grouped set of activities, SCE should list the activities in the priority order that SCE claims to have used to account for interrelationships among mitigations.

4. CONCLUSION

TURN appreciates the opportunity to submit these informal comments. TURN requests that SPD include the recommendations discussed above in its evaluation report for SCE's RAMP.

[33] SCE response to DR TURN-SCE-002, question 1(d).

[34] SCE response to DR TURN-SCE-002, question 1(a).

[35] Chapter 2 Excel Workpaper: SCE 2026 RAMP Optimization.

Dated: September 4, 2026

Respectfully submitted,

By: _____/s/_____
Thomas J. Long

Thomas J. Long, Outside Counsel
THE UTILITY REFORM NETWORK
360 Grand Avenue, #150
Oakland, CA 94610
Phone : (415) 929-8876
Email: tomjlong@sbcglobal.net