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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) Regarding 2022 Risk Assessment Mitigation Phase.	Application 22-05-___

APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) REGARDING 2022 RISK ASSESSMENT MITIGATION PHASE (RAMP)

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Dated: **May 13, 2022**

Application of Southern California Edison Company (U 338-E) Regarding 2022 Risk Assessment Mitigation Phase

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APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) REGARDING 2022 RISK ASSESSMENT MITIGATION PHASE (RAMP)

I.

INTRODUCTION

Pursuant to California Public Utilities Commission (CPUC or Commission) Rule 2.1 and Decisions (D.)18-12-014[1] and 21-11-009,[2] Southern California Edison Company (SCE) respectfully submits this 2022 Risk Assessment Mitigation Phase (RAMP) Application, covering the assessment and mitigation of key safety risks facing the company for years 2025-2028 (the RAMP Period). The Commission's RAMP process is an integral part of SCE's overall risk management process. RAMP is a pre-requisite to the filing of the General Rate Case (GRC), allowing the Commission to review in detail how SCE identifies and then proposes to address these critical safety risks.

Pursuant to the direction in the April 17, 2020 Amended Scoping Memo and Ruling of Assigned Commissioner and Assigned Administrative Law Judges in A.19-08-013 (*i.e.*, SCE's

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[1] D.18-12-014 is commonly referred to as the "S-MAP Settlement." Because of timing, the Commission exempted SCE's 2018 RAMP Report from the requirements of the S-MAP settlement.

[2] D.21-11-009 was issued in Rulemaking (R.)20-07-013 (*i.e.*, the Risk OIR).

2021 GRC) (the Amended Scoping Memo), SCE is filing this RAMP on May 13, 2022 – one year before SCE files its Test Year (TY) 2025 GRC Application. SCE's 2022 RAMP filing:

- Describes SCE's top safety risks;
- Explains how SCE analyzes and prioritizes each safety risk; and
- Evaluates mitigation activities for each risk, including by providing Risk Spending Efficiency (RSE) scores.

Funding is not authorized and the reasonableness of funding is not decided during the RAMP. In its subsequent TY 2025 GRC Application, SCE may update and modify (with explanation) the cost estimates, mitigation selections, and risk analysis and scoring set forth herein.

II.

BACKGROUND

A. Commission Guidance on RAMP

On November 14, 2013, the Commission issued the Risk OIR (R.13-11-006). The Risk OIR sought to incorporate a risk-based framework into the Rate Case Plan (RCP) that each Investor-Owned Utility (IOU) must follow. In the Risk OIR, the Commission instituted two new processes designed to feed into the portions of GRC Applications where utilities request funding for safety-related activities. These two processes were the Safety Model Assessment Proceeding (S-MAP) and the RAMP.

SCE's 2022 RAMP Application originates from, and is guided by, four key Commission decisions:

First, in the Risk OIR, the Commission issued D.14-12-025, which modified the RCP to include a risk-based framework and "provide a transparent process to ensure that the energy utilities are placing the safety of the public, and of their employees, as a top priority in their respective GRC proceedings."[3] The Decision indicated that each utility's RAMP Report should show:

- The utility's prioritization of the risks it believes it is facing and a description of the methodology used to determine these risks.
- A description of the controls currently in place, and the "baseline" costs associated with the current controls.
- The utility's prioritization of risk mitigation alternatives, in light of estimated mitigation costs in relation to risk mitigation benefits (a Risk Mitigated-to-Cost Ratio).
- The utility's risk mitigation plan, including an explanation of how the plan considers the following: utility financial constraints; execution feasibility; affordability impacts; and any other constraints identified by the utility.
- For comparison purposes, at least two other alternative mitigation plans for each major risk that the utility considered and an explanation of why the utility views these plans as inferior to the proposed plan to mitigate those risks.[4]

Second, the Commission issued an interim decision in the S-MAP proceeding. That interim decision, D.16-08-018, provided certain guidelines for what should be included in the utilities' RAMP Reports. The decision also guided the Commission's Safety Enforcement Division (SED) on what it should look for in evaluating the utilities' RAMP submissions and preparing its report on each utility's RAMP showing.

Third, the Commission's final decision approving the S-MAP settlement instituted a number of new requirements for utility RAMP submissions. For example, utilities are now required to "tranche" each modeled risk -- that is, break each risk as feasible into logical sub-parts and perform separate risk analysis for each sub-part.

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[3] D.14-12-025, p. 35.

[4] *See* D.14-12-025, pp. 31-32. The bullet points regarding the referenced Decision are intended for background purposes and are not intended to serve as any exhaustive listing of RAMP requirements.

Fourth, the Commission's recent Decision regarding Phase 1 and Phase 2 Issues in the Risk OIR included several new requirements for future RAMP filings.[5] The Decision on Phase 1 and 2 indicated that each utility's RAMP report should display the following:

- Each IOU shall establish baselines for mitigation measures as follows. The baseline is a reference point in time at the start of the new GRC cycle. The baseline risk as applied to RAMP and GRC proceedings refers to the amount of residual risk evaluated at the baseline (*i.e.*, at the start of the new GRC cycle) after taking into account all risk reduction benefits from all risk mitigation activities projected to have been performed by the start of the new GRC cycle. The projected risk mitigation activities include those that are classified by the IOUs as controls, as well as all mitigation activities for which the IOUs are seeking approval and/or funding in the current or upcoming RAMP and GRC applications.
- For foundational programs that support a portfolio of risk mitigations, the IOUs must include the cost of foundational programs when calculating RSEs of mitigations, if the aggregate cost (over the next GRC period) of the foundational programs exceeds prescribed thresholds.
- Each IOU shall model Public Safety Power Shutoff (PSPS) events as risk events pursuant to requirements in D.18-12-014 (and not just as a wildfire mitigation tool).
- Solely for informational purposes, SCE will be "test driving" a PG&E transparency proposal and will provide the relevant results within 60 days after filing this 2022 RAMP.

[5] *See* D.21-11-009.

B. SCE's 2018 RAMP Met All Applicable Requirements

In its detailed report concerning SCE's 2018 RAMP showing, SED found that SCE had met all applicable RAMP requirements.[6] SED also concluded that SCE "has pioneered the use of Multiple Variable Attribute Risk Score (MARS) framework to utilize data science tools to examine mitigation options and predict the value of a mitigation plan. This milestone establishes a risk modeling standard for RAMP proceedings."[7]

C. SCE Integrated its 2018 RAMP into its 2021 GRC

SCE integrated the results of its 2018 RAMP showing throughout its 2021 GRC testimony. SCE received positive feedback from the Commission's Safety Policy Division (SPD) regarding SCE's integration efforts, including in the joint RCP/Risk OIR workshop that occurred on February 9, 2021. SPD noted that SCE thoroughly addressed Commission Staff evaluations and stakeholder feedback and included a more useful "RAMP roadmap" by tying the GRC sections to the RAMP report. According to SPD, this enabled greater transparency and stakeholder input into SCE's GRC.[8] Further, the Commission acknowledged that in many ways, SCE's 2021 GRC Application was a major advancement in the development of a risk-based decision-making framework envisioned in D.14-12-025.[9] The Commission also concluded, as a matter of law, that "SCE's use of risk modeling to inform its GRC requests has enabled greater transparency and participation in this proceeding, increasing accountability for how safety risks are managed, mitigated, and minimized."[10]

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6 *See* "A Regulatory Review of Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case" (SED Report), p. 60. The SED Report is dated May 15, 2019 and was placed into the record of I.18-11-006.

7 *See* SED Report, p. 60.

8 *See* SMAP_Tr_3_RCP_Wrkshp_4_Presentation.pdf, slides 6 and General Rate Case Plan Workshop #4 Report - Standardization of RAMP Filings, March 11, 2021, p. 5.

9 *See* D.21-08-036, p. 36.

10 D.21-08-036, p. 649, Conclusion of Law 14.

D. Advances in SCE's Wildfire and PSPS Risk Modeling

Risk modeling and analysis has been a cornerstone in developing and executing our Wildfire Mitigation Plans (WMPs) and the annual updates to those Plans. Our approach has prudently matured over time. Since the 2018 RAMP, SCE has made significant progress in its wildfire and PSPS risk modeling capabilities.

For our 2018 RAMP, SCE developed a RAMP risk model and MARS framework (SCE's version of a Multi-Attribute Value Function (MAVF)) to quantify our enterprise-level risks and evaluate mitigation options. SCE's MARS model aligns with the methodology approved in the S-MAP Settlement. This analysis informed SCE's earlier wildfire mitigation work, as set forth in SCE's Grid Safety and Resiliency Program (GSRP) and 2019 WMP. In parallel, at that time we developed the Wildfire Risk Model (WRM), which was used to determine probability and consequence of ignitions at the asset level.

For the 2021 GRC and 2020 WMP, SCE continued to use the 2018 RAMP model and MARS framework to assess system- or High Fire Risk Area (HFRA)-level wildfire risks and risk mitigation using HFRA-level "top down" averages for probability and consequence of ignitions, and a "bottoms-up" approach for circuit segment mitigation prioritization, in conjunction with other operational considerations.

For this 2022 RAMP, we have subsequently developed asset-specific Probability of Ignition (POI) databases and have utilized a more refined fire consequence modeling tool. We have also developed a method to translate the risk scores produced by our POI and consequence models into unitless values consistent with the RAMP framework, using the MARS approach at the structure (pole or tower) level. In addition, SCE has developed a PSPS risk calculation at the circuit-segment level to more comprehensively account for wildfire risk reduction benefits, as well as the customer impacts associated with using PSPS as a necessary measure of last resort against wildfire ignition risk. All of these improvements and additions are integrated into the overarching model referred to as the Wildfire Risk Reduction Model

(WRRM). Then, in 2021, SCE further updated its models by using the latest asset, fire consequence, weather, fuel and burn scar data; as well as with updated algorithms.

Finally, as discussed at length in the Wildfire and PSPS Chapter, SCE has recently developed an Integrated Grid Hardening Strategy (IHGS), which takes into account both the quantitative risk factors discussed above as well as qualitative factors, such as egress risk. Egress risk is an important factor that SCE uses to determine whether to deploy targeted undergrounding as a replacement of existing overhead conductor.

E. Safety Culture and Related Issues

Safety is integrated into our business through our core values and vision. SCE is committed to delivering safe, reliable, affordable, and clean energy to its customers. Safety is our number one value, and part of that is making sure that we empower employees with the knowledge, motivation, and means to make safe choices. SCE is also committed to collaborating with our contractors to strengthen safe work practices, as well as educating the public to avoid hazards associated with our electrical grid. In the Chapter entitled "Safety Culture, Organizational Structure, Executive and Utility Board Engagement, And Compensation Policies Related to Safety," SCE describes its safety culture and performance, safety organizational structure, executive and senior management engagement, board engagement, and compensation policies related to safety.

III.

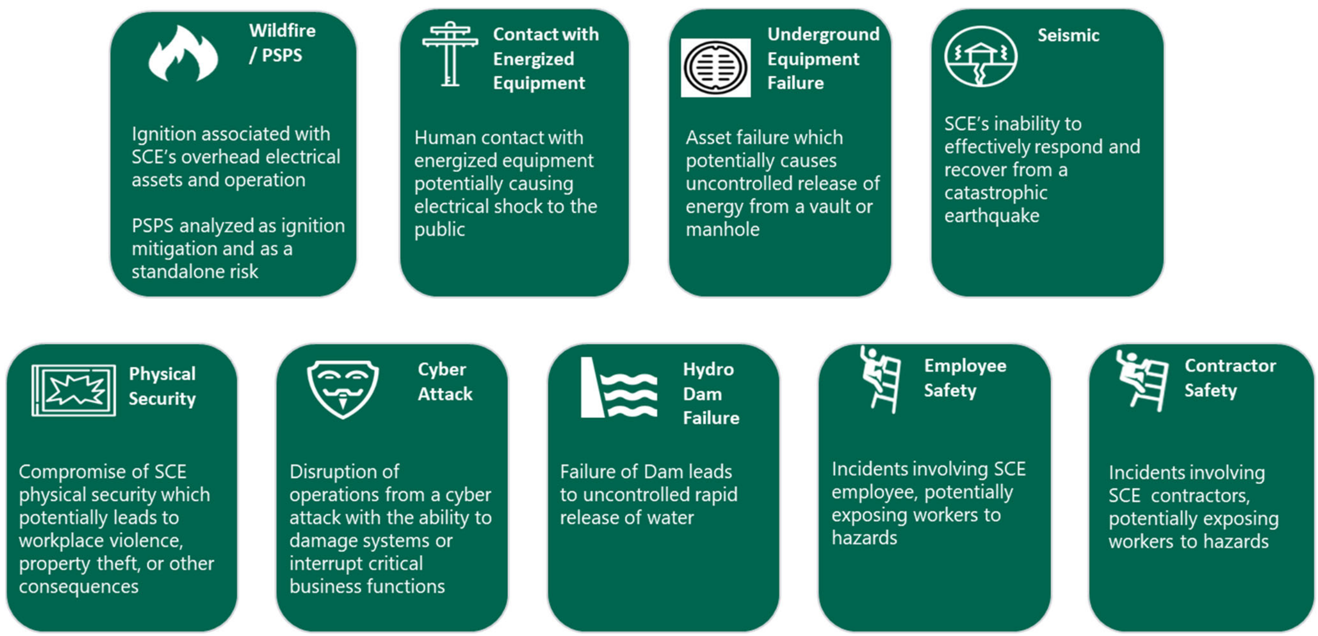
STRUCTURE OF SCE'S 2022 RAMP SUBMISSION

SCE's 2022 RAMP submission is separated into Chapters, starting with:

- Overview
- Risk Model and RSE Methodology
- Safety Culture and Compensation Policies

Following these opening Chapters, SCE's 2022 RAMP presents the company's enterprise-wide risks, in the following stand-alone Chapters:

SCE's RAMP Risks



Finally, this 2022 RAMP submission includes five Appendices:

- Appendix A – Battery Energy Storage Systems
- Appendix B – Climate Change
- Appendix C – Transmission and Substation Assets
- Appendix D – Nuclear Decommissioning (*i.e.*, SONGS)
- Appendix E – Widespread Outage

IV.

RELIEF SOUGHT

SCE respectfully requests through the disposition of this Application that:

- The Commission direct SPD to review SCE's 2022 RAMP Report and timely issue a regulatory review report consistent with the requirements of D.14-12-025 and D.20-01-002 and any other applicable Commission guidance; and
- The Commission close this proceeding upon such time as SCE has complied with applicable RAMP requirements.

V.

STATUTORY AND PROCEDURAL REQUIREMENTS

A. Statutory And Other Authority – Rule 2.1

Rule 2.1 requires that all applications: (1) clearly and concisely state authority or relief sought; (2) cite the statutory or other authority under which that relief is sought; and (3) be verified by the applicant. Rules 2.1(a), 2.1(b), and 2.1(c) set forth further requirements that are addressed separately below. The relief being sought is summarized above and is further described in the accompanying Track 4 testimony. The statutory and other authority under which this relief is being sought include various provisions of the California Public Utilities Code, the Commission's Rules of Practice and Procedure, and prior decisions, orders, and resolutions of this Commission, including D.14-12-025, D.20-01-002, and D.21-11-009. This 2022 RAMP submission has been verified by an SCE officer, consistent with Rule 1.11.

B. Legal Name and Correspondence – Rules 2.1(a) and 2.1(b)

Pursuant to Rules 2.1(a) and 2.1(b),[11] SCE is a public utility organized and existing under the laws of the State of California. The location of SCE's principal place of business is: 2244 Walnut Grove Avenue, Rosemead, California.

Correspondence or communications regarding this 2022 RAMP submission should be addressed to:

[11] Rule 2.1(a) requires an Application to state the exact legal name of the applicant and location of its principal place of business, and, if a corporation, the state under the laws of which the applicant was organized. Rule 2.1(b) requires the Application to state the name, title, address, telephone number, facsimile transmission number, and e-mail address of the person to whom correspondence or communications in regard to the application are to be addressed.

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C. Proposed Categorization, Need For Hearings, Issues To Be Considered, Schedule – Rule 2.1(c)

Commission Rule 2.1(c) requires that all Applications state "the proposed category for the proceeding, the need for hearing, the issues to be considered including relevant safety considerations, and a proposed schedule."[12] SCE respectfully requests that this 2022 RAMP be designated as "ratesetting." SCE does not believe evidentiary hearings are necessary, nor are they contemplated by Commission's proceeding schedule in D.20-01-002.[13]

SCE's proposed schedule is set forth below and has largely been pre-determined through the issuance of the Amended Scoping Memo.[14] In addition, because D.14-12-025 also includes two public workshops in the RAMP schedule (one following a utility's RAMP submission and another following the issuance of the Commission Staff report), SCE has included proposed dates for those events too, as well as other procedural events typical in utility RAMP proceedings. Finally, adhering to this schedule is important, because doing so will provide the time necessary for SCE to consider SPD's findings and parties' comments on its proposed mitigations and associated spending in the preparation of SCE's TY 2025 GRC forecast.

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[12] Title 20 Cal. Code Regs. Div. 1, Art. 2, §2.1(c).

[13] While the Amended Scoping Memo contemplates evidentiary hearings, SCE believes those hearings are intended to cover 2021 GRC Track 4-specific issues, not 2022 RAMP issues. *See also* Footnote 14, *infra*.

[14] Events and dates that are bolded in SCE's proposed schedule are taken directly from the Amended Scoping Memo. Please note that the Amended Scoping Memo's adopted schedule includes dates relevant to Track 4 of SCE's 2021 GRC (which is being filed concurrently with this 2022 RAMP), but SCE has omitted those dates from the proposed schedule set forth herein.

Event	Date
2022 RAMP Application Filed	**5/13/2022**
Protests and Responses	~6/16/2022
Reply to Protests and Responses	~6/27/2022
Post-filing workshop	6/30/2022
Pre-hearing Conference	~7/11/2022[15]
SPD Files and Serves Report on SCE's RAMP Submission	**9/1/2022**
Post-SPD Report Workshop	9/15/2022
Opening Comments on RAMP Submission and the SPD Report	**11/15/2022**
Reply Comments on RAMP Submission	**12/1/2022**
Filing of SCE's TY 2025 GRC	5/15/2023

D. Organization and Qualification to Transact Business – Rule 2.2

In compliance with Rule 2.2,[16] a copy of SCE's Certificate of Restated Articles of Incorporation, effective on March 2, 2006, and presently in effect, certified by the California Secretary of State, was filed with the Commission on March 14, 2006, in connection with Application No. 06-03-020,[17] and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series D Preference Stock filed with the California Secretary of State on March 7, 2011, and presently in effect, certified by the California Secretary of State, was filed with the Commission on April 1, 2011, in connection with Application No. 11-04-001, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series E Preference Stock filed with the California Secretary of State on January 12, 2012, and a copy of SCE's

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[15] For purposes of judicial economy, SCE has proposed a 2022 RAMP Prehearing Conference date concurrent with the date proposed in SCE's 2021 GRC Track 4 Request for that procedural milestone.

[16] Rule 2.2 requires the applicant to submit a copy of its organizing documents and evidence of its qualification to transact business in California, or to refer to that documentation if previously filed with the Commission.

[17] Application 06-03-020, *For Authority to Add City of Anaheim's Share of San Onofre Nuclear Generating Station Unit Nos. 2 & 3 (SONGS 2 & 3) to SCE's Rates and Associated Relief*.

Certificate of Increase of Authorized Shares of the Series E Preference Stock filed with the California Secretary of State on January 31, 2012, and presently in effect, certified by the California Secretary of State, were filed with the Commission on March 5, 2012, in connection with Application No. 12-03-004, and are incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series F Preference Stock filed with the California Secretary of State on May 14, 2012, and presently in effect, certified by the California Secretary of State, was filed with the Commission on June 29, 2012, in connection with Application No. 12-06-017, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series G Preference Stock filed with the California Secretary of State on January 24, 2013, and presently in effect, certified by the California Secretary of State, was filed with the Commission on January 31, 2013, in connection with Application No. 13-01-016, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series H Preference Stock filed with the California Secretary of State on February 28, 2014, and presently in effect, certified by the California Secretary of State, was filed with the Commission on March 24, 2014, in connection with Application No. 14-03-013, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series J Preference Stock filed with the California Secretary of State on August 19, 2015, and presently in effect, certified by the California Secretary of State, was filed with the Commission on October 2, 2015, in connection with Application No. 15-10-001, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series K Preference Stock filed with the California Secretary of State on March 2, 2016, and presently in effect, certified by the California Secretary of State, was filed with the Commission on April 1, 2016, in connection with Application No. 16-04-001, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series L Preference Stock filed with the California Secretary of State on June 20, 2017, and presently in effect, certified by the California Secretary of State, was filed with the Commission on June 30, 2017, in connection with Application No. 17-06-030, and is incorporated herein by this reference.

Copies of SCE's latest Annual Report to Shareholders and its latest proxy statement sent to its stockholders has been filed with the Commission with a letter of transmittal dated March 18, 2022, pursuant to General Order Nos. 65-A and 104-A of the Commission.

E. Service List

SCE is serving this 2022 RAMP on the current 2021 General Rate Case service list (A.19-08-013), the Risk-Informed Decision-making Order Instituting Rulemaking (R.20-07-013), and the S-MAP docket (A.15-05-005, *et. al.*).

Respectfully submitted,

CLAIRE E. TORCHIA
RUSSELL A. ARCHER

/s/ Russell A. Archer

By: Russell A. Archer

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Dated: May 13, 2022

RULE 1.11 VERIFICATION

I am an officer of the applicant corporation herein and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing document are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 12th day of May 2022 at Sierra Madre, California.

/s/ Michael Backstrom

Michael Backstrom
Vice President of Regulatory Affairs

SOUTHERN CALIFORNIA EDISON COMPANY

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(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

RAMP Overview

Chapter 1

Rosemead CA
May 13, 2022

Chapter 1: Overview

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I.

EXECUTIVE SUMMARY

Southern California Edison Company (SCE) appreciates the opportunity to present its Risk Assessment Mitigation Phase (RAMP) Report to the California Public Utilities Commission (Commission) and other Stakeholders. The Commission's RAMP process is an integral part of SCE's overall risk management process. SCE's 2022 RAMP focuses on assessing and mitigating key safety risks for years 2025-2028. RAMP is a pre-requisite filing of the General Rate Case (GRC), allowing the Commission to review in detail how SCE identifies and then proposes to address these critical safety risks.

SCE is filing this RAMP on May 13, 2022 – one year before SCE files its Test Year 2025 GRC application.[1] SCE's RAMP filing will:

- Describe SCE's top safety risks
- Explain how SCE analyzes and prioritizes each safety risk
- Evaluate mitigation activities for each risk. SCE's analysis includes Risk Spending Efficiency (RSE) scores. An RSE score estimates the risk reduction per dollar spent on the mitigation.

Spending is not authorized and reasonableness is not decided during the RAMP. In its subsequent GRC application, SCE may update and modify (with explanation) the cost estimates, mitigation selections, and risk analysis and scoring.

This is SCE's first RAMP filed under the requirements of the settlement reached in the Commission's Safety Model Assessment Proceeding (S-MAP).[2] Because of timing, the Commission exempted SCE's 2018 RAMP Report from the requirements of the S-MAP settlement.[3] SCE's 2022

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[1] Thus, this RAMP Report informs SCE's 2025-2028 GRC cycle.

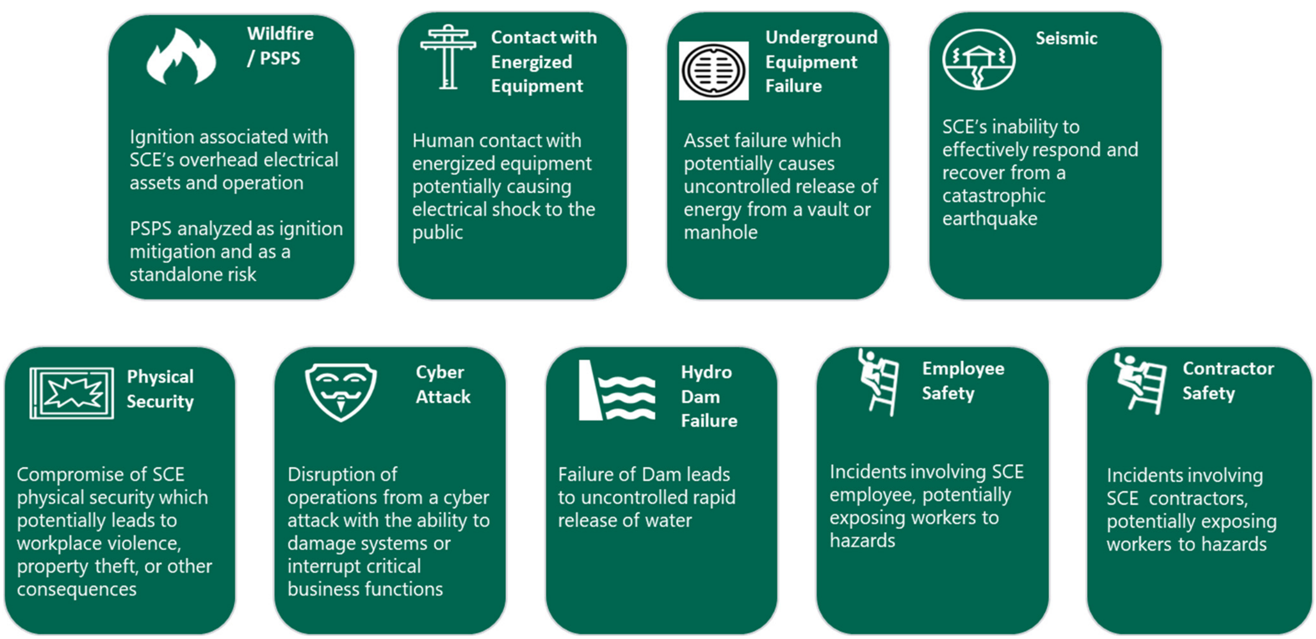
[2] A.15-05-002 *et al*.

[3] The Commission's final decision approving the S-MAP settlement was issued after the deadline for SCE to file its 2018 RAMP. *See* D.18-12-014, issued on December 13, 2018.

RAMP complies with the new requirements from the settlement, as well as a recent decision in the Commission's Risk-Informed Decision-Making Rulemaking (R.20-07-013).[4]

Our RAMP Report examines the top safety risks to our customers and the communities we are privileged to serve, to our company, and to our employees and contractors. After rigorous analysis pursuant to the terms of the S-MAP settlement, SCE identified these top safety risks that warranted inclusion in RAMP, as displayed in Figure I-1: *Wildfire/PSPS, Contact with Energized Equipment, Underground Equipment Failure, Seismic, Physical Security, Cyber Attack, Hydro Dam Failure, Employee Safety, and Contractor Safety.* Collectively, SCE refers to these top safety risks as RAMP Risks.

Figure I-1
SCE's RAMP Risks



The RAMP Risks in this report are substantially similar to the RAMP Risks that SCE presented in its 2018 RAMP. For reference, the general differences are as follows:

- The 2018 RAMP combined Employee and Contractor Safety in one RAMP chapter and overall risk analysis.

4 *See* D.21-11-009.

- The 2022 RAMP application provides separate risk chapters and analyses for Employee and Contractor safety.
- The 2018 RAMP only included Seismic as a sub-part of a RAMP Risk titled Building Safety.
    - The 2022 RAMP analyzes Seismic as a standalone RAMP Risk, and does not include Building Safety as a standalone RAMP Risk.
- The 2018 RAMP examined PSPS as an ignition mitigation for the Wildfire RAMP Risk.
    - The 2022 RAMP, per Commission direction, also assesses PSPS as a standalone risk.[5]

Moreover, the analysis of each RAMP Risk now occurs at a more granular level compared to our 2018 RAMP Report. In SCE's last RAMP, risks could be analyzed at the overall system level. In accordance with the S-MAP settlement provisions on risk tranching,[6] the 2022 RAMP breaks each risk into logical sub-parts and performs a separate risk analysis for each sub-part. For example, rather than analyzing employee safety from the lens of all employees, our 2022 RAMP analyzes field employees separate from office employees (and then further breaks down field employees into additional separate risk tranches).

Each of the RAMP Risks is explained and assessed in detail in the individual chapters of this Report. We analyze existing controls,[7] and identify new mitigations that can potentially enhance capabilities in addressing the RAMP Risks. For each mitigation plan, we also present two separate alternative mitigation plans that we considered. We outline why, out of the three plans, we chose the mitigation plan we have selected. Finally, we discuss lessons learned, address feedback from other stakeholders, and examine potential improvement opportunities for future RAMPs.

In addition to the RAMP Risk chapters, SCE also includes a chapter that outlines our risk methodology and calculations, and explains how the baseline for each risk was established. SCE is also

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[5] SCE has followed the Commission's preference. We respectfully note that the PSPS RAMP risk analysis does not classify it as a top safety risk for this RAMP period.

[6] *See* D.18-12-014, Attachment A – Settlement Agreement, Step 3. p. A-11.

[7] The term "control" refers to an activity performed prior to or during 2022 to address the risk, and that may continue through the RAMP period. Controls are modeled in this Report. In the context of SCE's proposed plan and two alternative plans for each RAMP Risk, the term "mitigation" refers to an activity commencing in 2023 or later that addresses the RAMP Risk. Mitigations are modeled in this Report.

submitting a chapter that discusses our compensation policies related to safety, the ongoing transformation of our safety culture as a whole, our enterprise risk management approach, and our engagement with and oversight of safety at the most senior levels of leadership at SCE.

Lastly, SCE is including the following five topics as appendices to the RAMP Report. These topics are addressed in appendix form either because they cut across multiple RAMP risks or have previously been suggested for inclusion through informal feedback from Commission Staff. The five appendices are:

- *Appendix A: Battery Energy Storage Systems* – This appendix discusses the applicable risk where deployment of Battery Energy Storage System assets continues to increase to help meet reliability and clean energy goals.
- *Appendix B: Climate Change* – SCE is filing its Climate Adaptation Vulnerability Assessment (CAVA) concurrently with its RAMP. SCE is integrating the CAVA into this appendix. Other climate models might potentially augment CAVA results as forecasts are prepared for the GRC.
- *Appendix C: Transmission and Substation Assets* – Although safety impacts from transmission and substation asset failure are covered within the main RAMP chapters, in this appendix SCE discusses (at a high level) the health of its transmission and substation electrical assets.
- *Appendix D: Nuclear Decommissioning* – In this appendix, SCE discusses the updated risk profile for the San Onofre Nuclear Generating Station (SONGS) since the 2018 RAMP, and summarizes the current state of risks, including dry fuel storage and execution of the Dismantling and Decommissioning (D&D) project phase.
- *Appendix E Widespread Outage* – This appendix addresses the risks associated with widespread outage to the extent not already covered in the RAMP chapters.

In sum, our 2022 RAMP Report represents a vital step in how we think about, plan for, and mitigate our top safety risks. The Report will inform the safety-related funding requests that we will include in our Test Year 2025 GRC application next year.

II.

BACKGROUND

A. Commission RAMP Guidance

On November 14, 2013, the Commission issued an Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the Rate Case Plan for Energy Utilities (R.13-11-006, or Risk OIR). The Risk OIR sought to incorporate a risk-based framework into the Rate Case Plan that each utility must follow. In the Risk OIR, the Commission instituted two new processes designed to feed into the portions of General Rate Case applications where utilities request funding for safety-related activities. These two processes were the S-MAP and the RAMP.

SCE's RAMP report originates from, and is guided by, four key Commission decisions.

First, in the Risk OIR, the Commission issued D.14-12-025, which modified the Rate Case Plan to include a risk-based framework and "provide a transparent process to ensure that the energy utilities are placing the safety of the public, and of their employees, as a top priority in their respective GRC proceedings."[8] The decision indicated that each utility's RAMP Report should show:

- The utility's prioritization of the risks it believes it is facing and a description of the methodology used to determine these risks.
- A description of the controls currently in place, and the "baseline" costs associated with the current controls.
- The utility's prioritization of risk mitigation alternatives, in light of estimated mitigation costs in relation to risk mitigation benefits (a Risk Mitigated to Cost Ratio).
- The utility's risk mitigation plan, including an explanation of how the plan considers the following: utility financial constraints; execution feasibility; affordability impacts; and any other constraints identified by the utility.

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8 D.14-12-025, p. 35.

- 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 proposed plan.[9]

Second, the Commission issued an interim decision in its S-MAP proceeding. That interim decision, D.16-08-018, provided certain guidelines for what should be included in the utilities' RAMP reports. The decision also guided the Commission's Safety Enforcement Division (SED) on what it should look for in evaluating the utilities' RAMP submissions and preparing its report on each utility's RAMP showing.

Third, the Commission's final decision approving the S-MAP settlement instituted a number of new requirements for utility RAMP submissions.[10] For example, as discussed above utilities are now required to tranche each risk -- that is, break each risk as feasible into logical sub-parts and perform separate risk analysis for each sub-part.

Fourth, the Commission's recent decision regarding Phase 1 and Phase 2 Issues in Rulemaking 20-07-013 included several new requirements for future RAMP filings.[11] The decision on Phase 1 and 2 indicated that each utility's RAMP report should display the following:

- Each IOU shall establish baselines for mitigation measures as follows. The baseline is a reference point in time at the start of the new GRC cycle. The baseline risk as applied to RAMP and GRC proceedings refers to the amount of residual risk evaluated at the baseline (i.e. at the start of the new GRC cycle) after taking into account all risk reduction benefits from all risk mitigation activities projected to have been performed by the start of the new GRC cycle. The projected risk mitigation activities include those that are classified by the IOUs as controls, as well as all mitigation activities for which the IOUs are seeking approval and/or funding in the current or upcoming RAMP and GRC applications.

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[9] *See* D.14-12-025, pp. 31-32. The bullet-points regarding the referenced decision are intended for background purposes, and are not intended to serve as any exhaustive listing of RAMP requirements.

[10] Each of the requirements is listed and addressed in WP. Ch. 1 – RAMP Compliance Requirements.

[11] *See* D.21-11-009.

- For foundational programs that support a portfolio of risk mitigations, the IOUs must include the cost of foundational programs when calculating RSEs of mitigations, if the aggregate cost (over the next GRC period) of the foundational programs exceeds prescribed thresholds.
- Each IOU shall model Public Safety Power Shutoff (PSPS) events as risk events pursuant to requirements in D.18-12-014.
- Solely for informational purposes, SCE will be "test driving" a PG&E transparency proposal, and will provide the relevant results within 60 days after filing RAMP.

B. SCE's 2018 RAMP Met All Applicable Requirements

In its detailed report concerning SCE's 2018 RAMP showing, SED found that SCE's RAMP met all applicable RAMP requirements.[12] SED also concluded that SCE "has pioneered the use of Multiple Variable Attribute Risk Score (MARS) framework to utilize data science tools to examine mitigation options and predict the value of a mitigation plan. This milestone establishes a risk modeling standard for RAMP proceedings."[13]

C. SCE Integrated its 2018 RAMP into its 2021 GRC

SCE integrated the results of its 2018 RAMP showing throughout its 2021 GRC testimony. SCE received positive feedback from the Commission's Safety Policy Division (SPD) regarding SCE's integration efforts, including in the joint Rate Case Plan/Risk OIR workshop that occurred on February 9, 2021. SPD noted that SCE thoroughly addressed Commission Staff evaluations and stakeholder feedback and included a more useful "RAMP roadmap" by tying the GRC sections to the RAMP report. According to SPD, this enabled greater transparency and stakeholder input into SCE's GRC.[14] Further, the Commission acknowledged that in many ways, SCE's 2021 GRC application is a major

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[12] *See* A Regulatory Review of Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case (SED Report), p. 60. The SED Report is dated May 15, 2019 and was placed into the record of I.18-11-006.

[13] *See* SED Report, p. 60.

[14] *See* SMAP_Tr_3_RCP_Wrkshp_4_Presentation.pdf, slides 6 and General Rate Case Plan Workshop #4 Report - Standardization of RAMP Filings, March 11, 2021, p. 5.

advancement in the development of a risk-based decision-making framework envisioned in D.14-12-025.[15]

The Commission also concluded, as a matter of law, that "SCE's use of risk modeling to inform its GRC requests has enabled greater transparency and participation in this proceeding, increasing accountability for how safety risks are managed, mitigated, and minimized."[16]

III.

SCE HAS MET WITH STAKEHOLDERS IN ADVANCE OF FILING OUR RAMP, AND PRESENTED INFORMATION ON THE RAMP RISKS, PRELIMINARY RISK SCORING, AND OTHER KEY AREAS

A. SCE Gave a Presentation at a Commission-hosted RAMP Pre-Filing Workshop

On December 6, 2021, the Commission hosted a pre-filing workshop for SCE's 2022 RAMP. SCE presented in detail on a number of aspects of its in-progress RAMP, including but not limited to the following:

- The preliminary selection of SCE's top safety risks, and additional substantive appendices;
- The preliminary safety risk scores for each risk in the Enterprise Risk Register;
- The preliminary Multi-Attribute Value Function (MAVF or "Risk Quantification") for the top 40% of those risks in the ERR that had a preliminary Safety Risk Score greater than zero;
- The specifics of the MAVF;
- A walk-through of the risk calculations for one of the RAMP Risks; and
- The individual parts of the RAMP showing, and of each RAMP Risk chapter.

A copy of SCE's presentation from this workshop is included in our workpapers.[17] SCE very much appreciated the thoughtful questions and feedback from the stakeholder audience, and as appropriate has incorporated them into the RAMP Report. At the conclusion of the workshop, neither the Commission nor any party indicated that they felt the need for any further pre-filing workshops.

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[15] *See* D.21-08-036, p. 36.

[16] D.21-08-036, p. 649, Conclusion of Law 14.

[17] Please refer to WP. Ch. 1 – SCE Pre-RAMP Workshop Presentation.

B. SCE Reached Out to The Public Advocates Office Regarding SCE's Mitigation Plans for Dam Failure Risk

In SCE's Test Year (TY) 2021 GRC decision, the Commission made a Finding of Fact that "SCE provided reasonable justification for the inclusion of its hydro risk asset alternative mitigation plan in the 2018 RAMP Report."[18] The GRC decision included what appeared to be dicta that "encouraged" coordination between SCE and the Public Advocates Office (Cal Advocates) regarding alternative migration plans for SCE's hydro risk assets in connection with the development of future RAMP submissions.[19]

In preparing its 2022 RAMP, SCE reached out to Cal Advocates to schedule a meeting to discuss SCE's planned alternative mitigations for hydro asset risk. SCE met with the Cal Advocates team on April 7, 2022. SCE briefed Cal Advocates in detail regarding the following: (a) SCE's planned controls and mitigations for the upcoming 2022 RAMP filing; (b) the specific controls and mitigations that SCE intended to select for SCE's Proposed Plan and two Alternative Plans; and (c) the reasons why individual controls and mitigations were included in the Proposed Plan versus an Alternative Plan.

SCE appreciates and thanks Cal Advocates for its courtesy and thoughtful questions during the meeting. SCE believes that the parties had a cooperative and productive conference, and SCE received positive feedback from Cal Advocates on SCE reaching out and coordinating the meeting, and on the substantive nature of the briefing. At the meeting, SCE did not receive any specific feedback regarding items that Cal Advocates wished to see treated differently in the alternative mitigations.

IV.

SCE'S RAMP MEETS ALL APPLICABLE REGULATORY REQUIREMENTS

To demonstrate its compliance with the applicable requirements for SCE's RAMP filing, SCE has provided a workpaper addressing each individual compliance requirement.[20] The format of the workpaper is similar to the compliance exhibit that SCE filed in Track 1 of the Test Year 2021 GRC, as

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18 D.21-08-036, p. 567, Finding of Fact 27.

19 D.21-08-036, p. 37.

20 Please refer to WP. Ch. 1 – RAMP Compliance Requirements.

well as prior SCE GRCs. The workpaper is intended to confirm for the Commission and stakeholders that SCE has submitted all required data, information, and analysis that the Commission requires for the RAMP Report.

We identified compliance action items by reviewing the provisions of the Settlement that the Commission approved in the S-MAP. We also re-examined Ordering Paragraphs, Conclusions of Law, Findings of Fact, and other guidance found in Commission decisions in RAMP proceedings.[21]

The compliance workpaper identifies the compliance action item, ordered by the proceeding in which the compliance item arose. For each compliance action item, we have provided the following information:

- The Commission decision or Public Utilities Code provision which resulted in the compliance action item. For example, "D.19-05-020 - Commission's 2018 GRC Decision" refers to SCE's Test Year 2018 General Rate Case decision.
- Action Required. This usually consists of a verbatim quote of the applicable language from the decision. In general, if the decision cite includes an Ordering Paragraph, the "Action Required" will only quote such Ordering Paragraph. In some instances, other decision language will be quoted if we believe it is helpful in clarifying the Action Required.
- Decision Reference. This indicates where in the Commission decision the identified compliance action may be found. The Decision Reference may refer to any combination of Ordering Paragraph, Conclusion of Law, Finding of Fact, or Discussion pages.
- Proof of Compliance. A brief summary is provided regarding the proof of compliance of any compliance action items, and/or a reference to SCE's RAMP chapters or workpapers pointing to where a particular item is addressed.

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[21] While SCE has made all reasonable efforts to address every applicable compliance item in the compliance workpaper, we appreciate feedback from the Commission and stakeholders in the event that we have inadvertently not included any salient requirement.

V.

ADVANCES IN SCE'S RISK MODELING

A. Wildfire and PSPS Risk Modeling

Since the 2018 RAMP, SCE has made significant progress in its wildfire and PSPS risk modeling capabilities. Risk modeling and analysis has been a cornerstone in developing and executing our Wildfire Mitigation Plan (WMP) and the annual updates to that Plan. Our approach has prudently matured over time.

For our 2018 RAMP, SCE developed a RAMP risk model and MARS framework (SCE's version of a Multi Attribute Value Function (MAVF)) to quantify our enterprise-level risks and evaluate mitigation options. SCE's MARS model aligns with the methodology approved in the S-MAP. This analysis informed SCE's Grid Safety and Resiliency Program (GSRP) and 2019 WMP. In parallel, we developed the Wildfire Risk Model (WRM), which was used to determine probability and consequence of ignitions at the asset level.

In 2019, SCE continued to use the RAMP model and MARS framework to assess system- or HFRA-level wildfire risks and risk mitigation using HFRA-level "top down" averages for probability and consequence of ignitions. Once the appropriate mitigation was selected for overall implementation (e.g., covered conductor), SCE used the segment-level probability of ignition (POI) and Reax-based consequence model[22] (together referred to as the WRM) to risk-rank conductor segments. This "top-down" RAMP model, along with the "bottoms-up" circuit segment prioritization, in conjunction with other operational considerations, was used to determine the prioritization of covered conductor installation in the field. The results of these analyses were included in SCE's Test Year 2021 GRC and 2020 WMP.

In 2020, SCE achieved several key milestones in enhancing our wildfire risk analytics. We developed asset-specific POI models for transmission and sub-transmission assets to add to our previously-built distribution asset models. SCE also transitioned from Reax to a new fire consequence

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22 Reax refers to Reax Engineering, whose specializations include wildland fire computer modeling.

modeling tool developed by Technosylva.[23] We developed a method to translate the risk scores produced by our POI and consequence models into unitless values consistent with the RAMP framework, using the MARS approach at the structure (pole or tower) level.

Finally, SCE developed a PSPS risk calculation at the circuit segment level to more comprehensively account for wildfire risk reduction benefits, as well as the customer impacts associated with using PSPS. All of these improvements and additions are integrated into the overarching model referred to as the Wildfire Risk Reduction Model (WRRM). In 2021, SCE updated its existing asset-specific WRRM POI models by using the latest asset data, weather data, and updated algorithms. Concurrently, SCE updated the Technosylva fire consequence models. We included additional historical weather scenarios and incorporated the most up-to-date fuel information, including the recent burn scars.

SCE also developed a Severe Risk Methodology to assess the risks associated with qualitative factors, such as egress risk. Egress risk is an important factor that SCE uses to determine whether or not to engage in targeted undergrounding of conductor.

Figure V-2 below traces the advancements in our wildfire and PSPS risk modeling.

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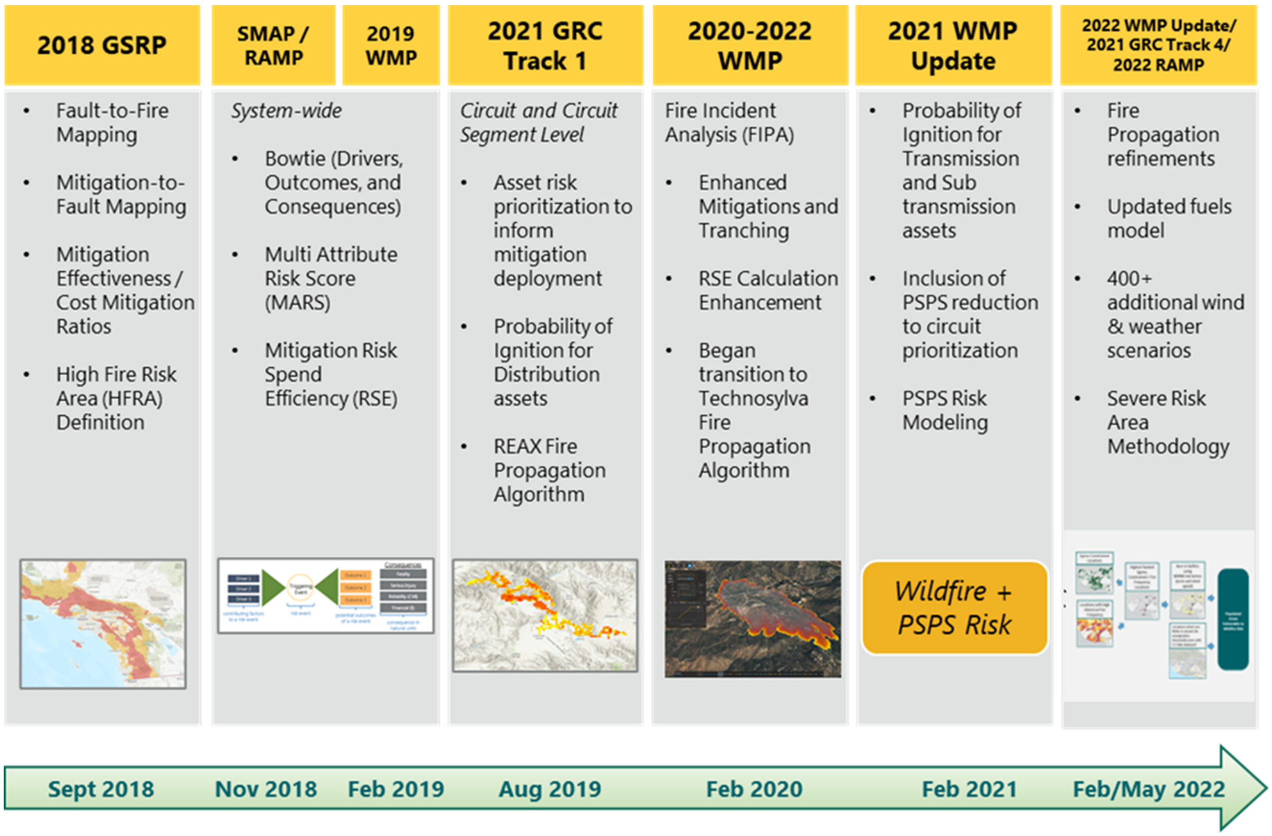
[23] *See* SCE 2022 WMP Annual Update, p. 60, submitted on February 18, 2022.

Figure V-2
Evolution of SCE's Wildfire (and PSPS) Risk Modeling



VI.

<u>Treatment of Climate Change in RAMP</u>

Climate change is a central concern for SCE, just as it is for the Commission and for so many Californians. In Appendix B to our RAMP Report, SCE addresses certain aspects of its efforts to help carry out the Commission's policies regarding climate change and California's resiliency to the effects of such change. Climate change is addressed in appendix form because it cuts across multiple risks. SCE notes the following five points related to this climate change risk.

<u>First</u>, under RAMP criteria established by the Commission, only a relatively narrow subset of climate change issues and strategies for mitigations fall within the parameters that are used to determine RAMP risks. Climate change is a long-term concern. Although we are beginning to experience the impacts of climate change, the magnitude of the risk is expected to increase significantly over the course

of the next several decades. And the impacts of climate change are not simply felt in the safety realm, but also in reliability, financial, and other critical areas.

In a sense, these aspects of climate change stand in contrast to the stated goals and boundaries of a utility's RAMP report. RAMP primarily examines and assesses the top safety risks that the utility faces in the shorter-term. But climate change is a risk whose *direct safety impact* today and in the shorter-term is a fraction of the totality of the risks, consequences, and outcomes that climate change is expected to bring in the next 10 years, or the next 20 years, or the next 40 years.

Thus, despite its critical importance and significant projected effects on public and private interests in the long run, the parameters and restrictions for RAMP risk calculations mean that climate change may not rise to the level of being one of the top safety risks that SCE faces in the near-term years that make up this RAMP cycle. The place where climate change "lands" as a safety risk under RAMP constraints is neither a true measure of its importance nor an accurate reflection of the priority that SCE places on it.

<u>Second,</u> in recognition of the long-term stakes that exist with respect to climate change, the Commission has directed the utilities to file long-term Climate Adaptation and Vulnerability Assessments (CAVAs).[24] SCE's CAVA is being filed on the same date as this RAMP Report. SCE is the first of the large California IOUs to file a CAVA.

There are important contrasts between what the Commission asks for in the RAMP and what the Commission asks for in the CAVA. RAMP must identify and examine the highest and most immediate safety risks that are implicated in the utility's activities and delivery of electricity to its customers. In assessing assets, operations and services (AOS), the CAVA must assess the vulnerability of the utility to the damaging effects of climate change on AOS. Also, the temporal scope of the CAVA assessments is longer-term. In the Commission's words, an IOU filing a CAVA must "[a]ddress the key time frame to be considered by the vulnerability assessment of the next 20 to 30 years. Also address the intermediate time frame of the next 10 to 20 years and the long-term time frame of the next 30 to 50

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24 The CAVA is discussed in Appendix B to this RAMP Report.

years."[25] Thus, because the timeframe of the CAVA stretches out to 50 years from today, the CAVA and RAMP do not neatly intersect for integration purposes.

Third, under the procedural schedule established by the Commission, the RAMP and CAVA file on the same date. As a result, the two regulatory submissions were developed somewhat in parallel rather than in serial fashion. SCE has worked to integrate CAVA results into the RAMP. But the RAMP is not the endpoint of integration of the CAVA. Over the next year, SCE will diligently continue its exploration of wider integration of the CAVA analyses and recommendations into affordable and actionable activities and projects that can be proposed in SCE's Test Year 2025 GRC. This is entirely consistent with the Commission's express guidance in both the text and the Conclusions of Law of the CAVA Decision:

"Instead of dictating a pathway for how to mitigate impacts of climate change, the vulnerability assessments should identify any challenges the IOUs will face due to climate change, and describe possible solutions ranging from easy to difficult. Thus, the assessments themselves will identify vulnerabilities and include a suite of options for consideration. The specific projects and mitigations themselves will be chosen in the GRC or other ratesetting proceeding seeking project funding. Thus, vulnerability assessments are an intermediate step in identifying options, and funding will be left to other decisions."[26]

Fourth, SCE is currently engaged in very significant efforts to mitigate the effects of climate change. But in the present, those efforts must take the form of mitigating the risk of climate-driven wildfires. The safety risk and devastating impact of California's wildfires have arisen from conditions created or directly exacerbated by climate change. SCE's nearer-term mitigation work to address the impacts of climate change focuses on the most immediate threat to the safety and well-being of our customers and communities.

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[25] D.20-08-046, p. 125, Ordering Paragraph 9.3. This decision is referred to as the "CAVA Decision."

[26] CAVA Decision, p. 72. *See also* CAVA Decision, p. 117, Conclusion of Law 56.

Fifth, in addition to the CAVA efforts referenced above, SCE is a national leader among utilities taking significant steps to reduce greenhouse gases (GHGs) minimize climate change as feasible, and help meet State and Federal climate change goals by driving a clean energy transition. We provide a summary in section II of the Climate Change Appendix (Appendix B).

VII.

KEY PARAMETERS AND ASSUMPTIONS UNDERLYING OUR RAMP

A. Direct vs. Secondary Impacts

In this RAMP Report, SCE has measured the immediate impacts of consequences and has not attempted to quantify secondary impacts. To give a simplified example, if electricity service is interrupted to a traffic signal light, the direct impact is that the signal light is out. An indirect impact of the power being out could be an auto accident occurring due to the lack of a functioning signal light.

SCE appreciates how non-direct impacts may manifest themselves in some risks. But ultimately, the definition of what types of consequences constitute a secondary impact has not been established by the S-MAP settlement, much less how to evaluate it within the context of the MAVF.

There are challenges in collecting data and establishing an appropriate level of certainty for secondary or indirect impacts. These hurdles must be addressed, particularly when dealing with the tranche-level modeling that is mandated under current RAMP requirements. Any approach that the Commission may choose to direct must avoid, among other things, unintentional distortion of baseline risks or RSE results. SCE welcomes the opportunity to discuss challenges in incorporating secondary impacts into risk analysis in future technical workshops as contemplated by the Risk OIR.

B. RAMP Time Period

SCE has evaluated the risk, reduction and RSEs for each of the risk chapters over the 2025-2028 period, which is SCE's upcoming GRC period. For purposes of calculating risk reduction and RSEs, the initial starting baseline will be the end of the 2024 period. More details concerning the baseline can be found in Chapter 2, Section 4 (Risk Calculation).

C. Financial Information Provided in RAMP

1. Cost Estimates

For the 2025-2028 RAMP period, SCE has developed preliminary cost estimates for each control and mitigation activity. The costs are not jurisdictionalized, so they include both CPUC and Federal Energy Regulatory Commission (FERC) costs. They represent total company unadjusted expenditures regardless of regulatory cost recovery mechanism. SCE presents these costs, both O&M and capital, in nominal dollars. For controls and mitigations funded through capital expenditures, SCE does not include capital-related expense, which typically amounts to approximately 2-3% of the capital expenditures. SCE will include capital-related expense in the 2025 GRC.

It is crucial to note that these costs are estimates at a point in time. SCE has developed our preliminary projected costs for each control and mitigation based on the information reasonably available at the time that we developed this RAMP report. This information is provided a full year in advance of the GRC forecasts for the controls and mitigations. Those forecasts will be developed and refined prior to being included in the GRC application. Moreover, the GRC forecasts will appropriately integrate feedback we receive in the course of this RAMP proceeding, including the regulatory review issued by the Commission's Safety Policy Division.

2. Recorded Costs

SCE has provided workpapers that detail the recorded and projected costs for each control and proposed mitigation activity modeled in our RAMP report from 2017 – 2028.[27] These costs represent total company, unadjusted costs in nominal dollars, including balancing/memorandum accounts.

D. Use of SME Assessments in RAMP

Wherever possible and practicable, SCE has used data pertaining to our customers and our system to buttress the 2022 RAMP risk analyses. When this is not available, we look to other utilities in California, or other utilities around the country, for data and information comparable to our operating

[27] For certain controls and mitigations, SCE may not have historical costs at the tranche level.

environment and size. When such data does not exist, we reasonably rely on the judgment of subject matter experts (SMEs) to develop assumptions for risk models.[28] Where this occurs, SCE has endeavored to explain the assumptions and processes used to develop such judgment. Please refer to the individual RAMP Risk chapters and associated workpapers for details.[29]

VIII.

RISK SPENDING EFFICIENCY SCORES ARE ONLY ONE OF SEVERAL FACTORS THAT MUST BE CONSIDERED IN A PRUDENT RISK-INFORMED DECISION-MAKING PROCESS

Like other stakeholders, SCE appreciates that RSEs represent a measure of risk reduction per dollar spent. RSE represents a relative measure of estimated cost-effectiveness for actions a utility takes to mitigate a specific risk. RSE scores may offer certain insights into how effective a mitigation appears to be in reducing risk at a system, or portfolio level, while providing guidance on how effective new mitigations may appear to be. But RAMP RSEs are based in part on assumptions and preliminary cost projections, and thus should be viewed as point-in-time approximations one full year in advance of GRC forecasting.

It is also crucial to recognize that RSEs are not and should not be the only factor used to develop a proposed risk mitigation plan. The RSE metric does not take into account certain operational realities, resource constraints, and other factors that SCE must consider in developing its mitigation plan. For example, if one were to consider PSPS as an ignition mitigation, then despite a seemingly attractive RSE score there are critical practical and regulatory limits to how much PSPS can be deployed. SCE tries to minimize the use of PSPS given the hardships they cause for our customers. Indeed, the

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28 These categories of information are not mutually exclusive. For example, the availability and use of SCE-specific data does not cancel out exercising appropriate judgment.

29 Please refer to individual RAMP chapter workpapers describing the data sources leveraged, rationale and/or methodology associated with the baseline risk numbers, and mitigation inputs. A data file that includes RSEs at the tranche level will also be provided at https://www.sce.com/regulatory/CPUC-Open-Proceedings.

Commission expressly prescribes that PSPS should be used "as a last resort" despite any relatively high RSE.[30]

Accordingly, to address the most pressing safety risks facing the Company, SCE develops a comprehensive and balanced mitigation plan with activities that will collectively reduce the greatest amount of risk in the shortest amount of time, considering RSE as well as various regulatory, operational, resource, and cost constraints. To do otherwise would not be prudent. For example, it would be inappropriate to implement a comprehensive wildfire risk mitigation plan based solely on RSEs, which would likely lead to significant parts of the system and potentially significant risk issues being left unaddressed.

The Commission's Safety and Enforcement Division (SED) has stated that focusing solely on RSEs in selecting mitigations could be "suboptimal from an aggregate risk portfolio standpoint."[31] This feedback was included in SED's regulatory review of PG&E's 2017 RAMP Report. SED also acknowledged that "mitigations are usually selected based on the highest risk spend efficiency score **unless there may be some identified resource constraints, compliance constraints, or operational constraints that may favor another candidate measure with a lower RSE**."[32]

In sum, the RSEs found in this RAMP Report are an important consideration for sound risk-informed decision-making. But they are not, and cannot, serve as the sole barometer when making operational decisions and prioritizing mitigation efforts.

IX.

AVAILABILITY OF RISK MODEL DATA AND RESULTS

For each RAMP chapter, SCE provides workpapers describing the data sources leveraged, rationale and/or methodology associated with the baseline risk numbers, and mitigation inputs. A data

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[30] *See* D.21-06-034, p. 17, *citing* D.19-05-042, Appendix A at A1; D. 20-05-051, Appendix A at 9.

[31] California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company Investigation 17-11-003 (March 30, 2018), p. 18.

[32] California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company Investigation 17-11-003 (March 30, 2018), p. 18 (emphasis added).

file that includes RSEs at the tranche level will also be provided on SCE's website.[33] Workpapers not submitted concurrently with our RAMP filing will be provided within 14 days or less of the filing date.

33 https://www.sce.com/regulatory/CPUC-Open-Proceedings.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Risk Model and RSE Methodology

Chapter 2

Rosemead CA
May 13, 2022

Chapter 2: Risk Model and RSE Methodology

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I.

SUMMARY

A. Introduction

In this chapter, SCE provides an overview of its risk analysis framework, in conformance with D.18-12-014 ("S-MAP Settlement"). This structure was used in quantifying and analyzing the RAMP Risks. This chapter contains three framework sections:

- Section II – Describes how SCE developed the Multi-Attribute Value Function (MAVF), the risk metric by which the RAMP Risks are scored.
- Section III – Describes how SCE utilized the bowtie methodology to break down the risk into its respective risk drivers, and associated outcomes and consequences.
- Section IV – Describes the framework for calculating risk reduction and Risk Spend Efficiency (RSE) scores for programs that reduce risk.

Section V provides a roadmap of the workpapers associated with each RAMP chapter. Finally, in Section VI, SCE will address feedback provided through the Pre-Filing RAMP workshop conducted on December 6, 2021.

B. Key Changes from 2018 RAMP

SCE's 2022 RAMP report will be our first RAMP that is governed by the terms of the S-MAP Settlement. As background, SCE's 2018 RAMP was filed on November 15, 2018. Approximately one month later, the Commission issued a final decision for the S-MAP Settlement.[1] SCE carried over many of the foundational risk analysis elements from its 2018 RAMP into the 2022 RAMP report.
This includes elements such as our development of the risk bowties as explained in Section II below.

Based on Commission guidance, a key change found in the 2022 RAMP is a more granular risk analysis, with each risk broken down into logical sub-parts for analysis purposes (the applicable requirement uses the phrasing "risk tranches"). For example, in the Employee Safety Risk Chapter, field employees are analyzed separately from office employees, reflecting the different risk profile that exists

[1] The Commission issued the S-MAP Settlement decision (D.18-12-014) on December 13, 2018.

for each of these employee tranches. (SCE then further breaks down the field employee tranche into sub-tranches.)

SCE's risk analysis does not start and stop at the inception of each RAMP cycle, but instead continues to evolve and be refined in the intervening years between RAMP filings. As an example, the wildfire model in the 2018 RAMP was based on a system-level analysis, using historical data for risk driver probability and consequences. For 2022, SCE has developed an asset-based wildfire probability model based on machine learning, and we have incorporated a fire simulation tool (Technosylva) to inform wildfire consequence modeling.

In addition, SCE has advanced our risk analysis for PSPS and its impact on the communities we serve. In the 2018 RAMP, PSPS was addressed solely as a wildfire ignition mitigation. In our current RAMP, SCE now examines PSPS both as an ignition mitigation, and as a standalone risk. This technical and quantitative progression is discussed in more detail in the Wildfire/PSPS chapter of our RAMP Report, as well as in SCE's most recent WMP Annual Update.[2] Table I-1 below provides additional details for ease of reference. In the table, WRM stands for Wildfire Risk Model. WRRM stands for Wildfire Risk Reduction Model. Further details regarding these models are found in the Wildfire Risk chapter.

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[2] *See* SCE's 2022 Wildfire Mitigation Plan Update February 18, 2022. Section 4 – Lessons Learned and Risk Trends.

Table I-1
Updating of Modeling

Year	Model Name	WF Probability Component	WF Consequence Component	PSPS Probability Component	PSPS Consequence Component
2019	WRM	SCE Machine Learning (ML)	Reax Consequence	Not captured	Not captured
2020	WRRM	SCE ML	Technosylva consequence	Probability of PSPS De-energization	Consequence of PSPS De-energization
2021	WRRM	SCE ML (Updated with latest available data)	Technosylva Consequence (Updated with latest fuel data and more weather scenarios)	Probability of PSPS De-energization (Updated with latest PSPS operation protocols)	Consequence of PSPS De-energization (Updated with latest customer and circuit connectivity data)

By leveraging the risk analysis framework we have developed for wildfire, SCE was able to improve the granularity of tools and risk analysis for other risks. For instance, SCE developed Probability of Failure models associated with wire down and underground failures. Thus, we have been able to supplement our modeling of safety consequences in connection with public safety. We describe these improvements in greater detail in the Contact with Energized Equipment (CEE) and Underground Equipment Failure (UEF) Risk chapters.

II.

MULTI-ATTRIBUTE VALUE FUNCTION (MAVF)

A. Overview

The MAVF is a framework to combine different consequences (e.g., safety, reliability and financial) into a generic unitless risk score, so that risks and mitigation alternatives can be compared on a uniform scale. The same unitless risk score can be used, as appropriate, to compare scores across different risks and their respective mitigations, given that the generic unitless score itself has no visible standalone value. The risk score that is generated from SCE's MAVF scoring framework is called the multi-attribute risk score (MARS). A MARS score of 10, for example, by itself does not inform the reader whether it is a high or low score. It must be evaluated in relation to the scores for other risks to fully appreciate the order of magnitude difference between risk scores.

There is perhaps a natural tendency to want to compare scores between different IOUs. However, each utility individually contours its MAVF construction based on the guidelines provided in the S-MAP settlement. Thus, it is not practical to make meaningful direct comparisons of risk scores across the IOUs. As an example, both PG&E and Sempra have a natural gas component to their overall business, while SCE does not. Accordingly, PG&E's and Sempra's MAVF factors in gas reliability (weights and ranges). This factor alone skews the results of the reliability MAVF component when trying to make comparisons with SCE. This is true even if each utility appears to similarly characterize the broad parameters of the risk itself (i.e., risk drivers, triggering event, mitigations, etc.).

SCE looks forward to continuing to work with Staff and stakeholders in Phase II of the Risk-Based Decision Making Framework (R.20-07-013) in discussing potential ways to meaningfully examine risk scores amongst different utilities.

The following section describes the steps that SCE took to construct the latest iteration of MARS, including selecting attributes and units, ranges, scaling function, and weightings. At the conclusion of Section II, SCE provides an illustrative example of how these different MARS components work together to arrive at a single risk score.

B. Construction

1. Summary

SCE developed its MAVF based on the six principles as set forth in the S-MAP Settlement.[3] These principles drove the process by which SCE developed the requisite components of its MAVF, as well as the combination of these elements for generating appropriate MARS scores. MARS serves as the basis for calculating RSEs and then comparing the RSEs with each other.

3 *See* S-MAP Settlement Agreement, pp. A-5 – A-6.

Table II-2 presents an overview of SCE's MAVF, including the associated attributes, units, weights, ranges, and scaling functions.

Table II-2
Multi Attribute Value Function (MAVF)

Attribute	Units	Weight	Range	Scaling
Safety	Index	50%	0 - 100	Linear
Reliability	Customer Minutes of Interruption (CMI)	25%	0 - 2 Billion	Linear
Financial	Dollars	25%	0 - 5 Billion	Linear

2. Attributes and Units

S-MAP Settlement Principle 1 – Attribute Hierarchy: Attributes are combined in a hierarchy, such that the top-level Attributes are typically labels or categories and the lower-level attributes are observable and measurable.[4]

SCE identified 3 top-level attributes: 1) Safety, 2) Reliability, and 3) Financial. These three attributes comport with the S-MAP Settlement requirements that Safety, Reliability and Financial consequences are included. Pursuant to the referenced S-MAP Settlement Principle, the lower-level attribute for Safety are a combination of observable and measurable attributes, namely serious injuries and fatalities. For purposes of risk modelling, SCE used a safety index to combine these two lower-level safety attributes in the following manner: *Safety Index = (# of fatalities) + ¼ * (# of serious injuries).* This approach is consistent with the direction that both SDG&E and PG&E have taken. The lower-level observable and measurable attribute for Reliability is customer minutes of interruption (CMI). The lower-level observable and measurable attribute for Financial is Dollars.

In considering what other attributes to incorporate into its MAVF, SCE's due diligence included reviewing both SDG&E and PG&E's most recent RAMP reports. PG&E incorporated

[4] The term "attribute" is defined in the S-MAP Settlement, and the same meaning applies here.

environmental consequences into its Financial attribute. SDG&E included air quality, modeled as a function of wildfire acres burned, within its Safety attribute.

SCE considered using various environmental metrics related to air quality and water impacts based on the relevance of those factors to specific RAMP Risk chapters. SCE factored in the associated data needed to model these environmental attributes, while also recognizing the need to balance the level of data collection with the actual impact this type of analysis may have on the RAMP Risk scores for those chapters.

The air quality environmental impact attribute, for instance, would have factored primarily into the wildfire RAMP Risk chapter. However, including this attribute would necessarily have led to offsetting and reallocating some of the attribute weight from the other attributes (safety, reliability, and financial) in favor of an environmental attribute, applicable solely to this specific risk. This may have led to the unintended consequence of diminishing the importance of those other attributes, including Safety. In addition, the other attributes represent direct impacts from the risk event. In contrast, analyzing and giving weight to a more indirect impact such as effect on air quality can be a less reliable exercise. Among other reasons, parties may reasonably disagree on whether a change in air quality sprang from the risk event, or whether it sprang from a different cause, or whether it sprang from some unknown combination of the risk event and other causes.

Ultimately, SCE determined that our MAVF should emphasize applicability to all RAMP safety-driven risks, rather than focus primarily on specifically targeted risk(s). As such, SCE did not implement a specific environmental attribute into the 2022 RAMP. We look forward to continued discussion on this topic in Phase 2 of the Risk OIR.

SCE appreciates that Sempra attempted to incorporate stakeholder impact into their MAVF. SCE also explored different avenues to collect quantitative data, and experienced similar challenges outlined in Sempra's RAMP filing regarding the availability of data.[5] Therefore, we determined, given the sparsity of data, as well as the inherent subjectivity associated with modeling this

[5] *See* A.21-05-011, RAMP-C Risk Quantification Framework and Risk Spend Efficiency. pp. C-20 – C-21.

attribute, a prudent course would be to qualitatively describe the impact to stakeholders. Perhaps most importantly, after considering the issue in the context of Sempra's RAMP, the Commission directed that Sempra **eliminate** the Stakeholder Satisfaction attribute from the MAVF when preparing its upcoming General Rate Case (GRC) showing.[6]

3. Ranges

S-MAP Settlement Principle 2 – Measured Observations: Each lower-level Attribute has its own range (minimum and maximum) expressed in natural units that are observable during ordinary operations and as a consequence of the occurrence of a risk event.

SCE selected the safety range to be between 0 and 100. The maximum safety range was chosen based on the 2018 Camp Fire, which caused over 80 fatalities. For the reliability attribute, SCE used the 2011 Southwest blackout event on September 8, 2011 as the basis for the maximum range of 2 billion CMI. Finally, to set a range for the financial attribute, SCE used the Woolsey Fire (2018) as the basis for the maximum range of 5 billion dollars. Although there have been other more destructive and catastrophic financial losses observed in California's history, SCE chose the financial range based on its recency and in light of the paramount importance of mitigating wildfire risk.

S-MAP Settlement Principle 3 – Comparison: Use a measurable proxy for an Attribute that is logically necessary but not directly measurable.

SCE's lower-level attributes are measurable and observable. Therefore, this principle is not applicable.

S-MAP Settlement Principle 4 – Attributes: When Attribute levels that result from the occurrence of a risk event are uncertain, assess the uncertainty in the Attribute levels by using expected value or percentiles, or by specifying well-defined probability distributions, from which expected values and tail values can be determined. This principle is addressed in Section III below, so that the practical context of the application of this principle can be shown in step-by-step fashion.

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[6] *See* A.21-05-011, Assigned Commissioner's Ruling Directing Sempra Utilities to Incorporate Staff Recommendations on Their Risk Assessment And Mitigation Phase In The Upcoming 2024 General Rate Case Applications, p. 3.

4. Scaling Functions

S-MAP Settlement Principle 5 – Scaled Units: Construct a scale that converts the range of natural units (Principle 2) to scaled units to specify the relative value of changes within the range, including capturing aversion to extreme outcomes or indifference over a range of outcomes.

SCE selected a linear scaling function, which converts an attribute's natural units to a scaled unitless score between 0 to 100, for all three attributes. A key difference between our 2018 RAMP report and 2022 RAMP Report is the shift of the safety consequence from a non-linear to a linear scaling function to reflect that each incremental safety event is valued the same as the previous one. The scaled score of 100 was taken directly from the S-MAP lexicon of a "Scaled Unit of an Attribute," which prescribes the value to be in terms of 0-100.

5. Weights

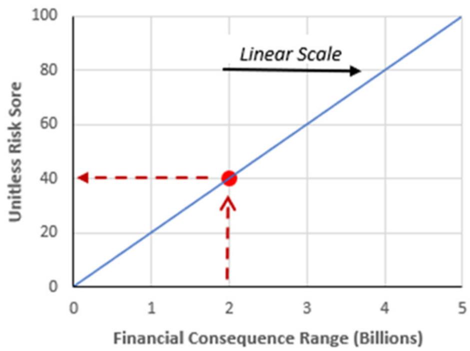
S-MAP Settlement Principle 6: Relative Importance: Each Attribute in the MAVF should be assigned a weight reflecting its relative importance to other Attributes identified in the MAVF. Weights are assigned based on the relative value of moving each Attribute from its least desirable to its most desirable level, considering the entire range of the Attribute.

SCE selected the following weights for each attribute: Safety – 50%, Reliability – 25% and Financial – 25%. The 50% Safety weight complies with the S-MAP Settlement minimum Safety weight of 40% and is consistent with what SCE used in its 2018 RAMP MAVF. Having allocated 50% to Safety, the remainder of 50% is left to allocate between the Reliability and Financial Attributes. Based on the relative value of moving the Reliability range from 2 billion CMI to 0 and the Financial range from $5 billion to $0, SCE believes that equal weighting is appropriate. Thus, for purposes of RAMP analysis we assigned 25% to the Reliability Attribute, and 25% to the Financial Attribute.

C. Illustrative Example

Table II-3 below provides a step-by-step example of using the aforementioned weights, ranges and scaling function to transform a natural unit consequence (e.g., Financial consequence in dollars) into a MARS score.

Table II-3
Step by Step Example



Step	Action	Value
1	Identify Consequence Value	$2 Billion
2	Determine Scaled Score	40
3	Identify Attribute Weight [Financial]	25%
4	Apply Weight to Scaled Score	10 = 25% * 40
5	**Financial Risk Score (MARS)**	**10**

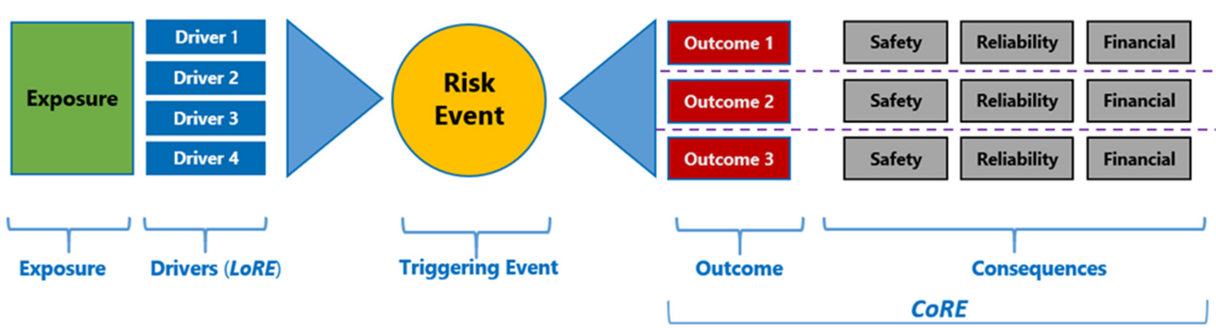
III.

BOWTIE METHODOLOGY

A. Overview

The risk bowtie provides a simple and effective means of translating a particular risk event into its drivers and consequences. As illustrated in Figure III-1 below, a bowtie can be broken down into a number of key components: 1) Exposure, 2) Likelihood of Risk Event (LoRE), and 3) Consequence of Risk Event (CoRE). In the RAMP Risk chapters, SCE will present a bowtie for each RAMP Risk and discuss in more detail the data that was used to populate the bowtie. The sections below will describe, on a more general basis, the individual components that make up a risk bowtie.

Figure III-1
Illustrative Risk Bowtie



B. Exposure

The exposure describes the overall population that is encompassed by the risk. For example, if the risk is a wildfire event, the risk population could include the total miles within the service territory. Or it may be more focused and use those miles in the High Fire Risk Area. This exposure is usually used in conjunction with the scope of a mitigation program to normalize the effectiveness of a mitigation.

C. Drivers / Likelihood of Risk Event (LoRE)

Risk drivers are the factors causing the risk event. They can range from one to many risk drivers, depending on the granularity of data collection. Examples of risk drivers for the Wildfire risk can include Contract From Object-Animal and Contact From Object-Balloons. The measurement units of risk drivers may be expressed as a likelihood, as alluded to by the "Likelihood of Risk Event" (LoRE) lexicon. SCE has instead chosen to use an annualized frequency. The frequency approach lends itself to a more intuitive understanding of the estimated number of risk events.

For example, if the annualized historical average number of wire down events is 800, conveying that information in a likelihood/probabilistic manner would likely provide little to no value to the reader. The reader would only know that the likelihood of a wire down event is near 100%. Furthermore, if one wished to forecast how many wire downs events would happen given a certain level of mitigation deployment, a frequency approach would convey that the number of wire down events decreased from 800 to 750; this is an easy-to-understand metric. In contrast, with a likelihood approach, the reader would only know that the likelihood of a wire down event dropped from 100% to some slightly smaller percentage.

The Commission's Safety Policy Division Staff Evaluation Report (Evaluation Report) on PG&E's 2020 RAMP Application (A.20-06-012) supports the frequency approach. The observations in the Evaluation Report stated the following: "Staff believes the PG&E use of frequency is a practical way of accounting for risk when more than one event is expected per year, such that the likelihood is greater than one."[7] Given that all of SCE's RAMP Risks have a risk event frequency greater than one, except

[7] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/pge-2020-ramp-evaluation-report-final.pdf, p. 22.

for Hydro Dam Failure and Seismic, SCE has decided to use frequency for all of the RAMP Risks, in order to maintain consistency.

D. Triggering Event

The triggering event is characterized by the event-based risk statement. More specifically, it is characterized by the annualized number of times the risk event has happened. The individual frequency of each risk driver can be added together to arrive at the total number of risk events annually.

E. Outcome and Consequence of Risk Event (CoRE)

In developing the bowtie, SCE incorporated Outcomes and Consequences to reflect the probabilistic manner of consequences given that a risk event has already occurred. Outcomes are represented as a percentage from 0 – 100 %. The total sum of all outcome percentages must equal 100%. SCE selected the outcomes to generally convey different gradients of severity, essentially a stratified distribution.

Take, for example, a Hydro Dam failure risk event. In one outcome (Outcome 1), the risk event may result in no significant inundation, while in another outcome (Outcome 2), it may result in significant inundation in a populated area. The consequences (measured on a per risk event level) for the Outcome 1 may result in only financial consequences. In comparison, in Outcome 2 there could be significant inundation in a populated area, resulting in significant consequences in all three Attribute areas - safety, reliability, and financial.

Accordingly, the consequence scores associated with each outcome reflect the severity level of that particular outcome. The consequences for each outcome are based on expected value of a given risk event. Consequences are, in most cases, calculated from historical occurrences, simulated data,[8] as well as, in some instances Subject Matter Expert (SME) judgement. The choice of Outcomes and Consequences are discussed further in each RAMP Risk chapter. Our methodology comports with *S-MAP Settlement Principle 4 – "When Attribute levels that result from the occurrence of a risk event are uncertain, assess the uncertainty in the Attribute levels by using expected value or percentiles, or by*

[8] E.g., Technosylva for Wildfire.

specifying well-defined probability distributions, from which expected values and tail values can be determined." There is alignment here because SCE is using the expected value based on the different outcomes.

IV.

RISK CALCULATION

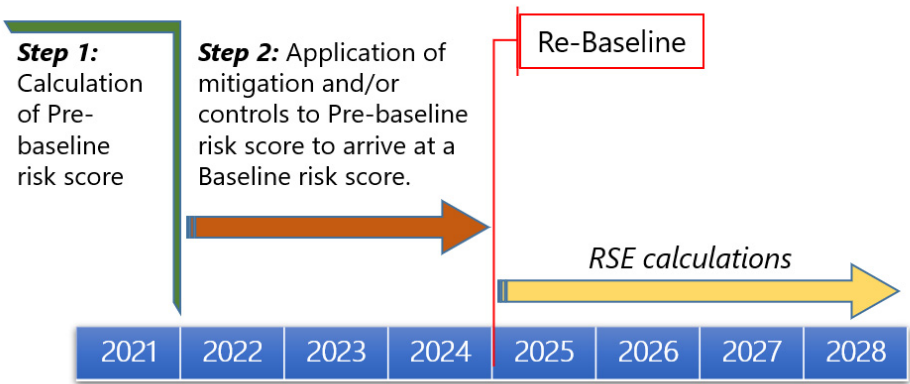
A. Overview

The risk calculation relies on the MAVF and the risk bowtie development as previously discussed, and focuses on two key aspects: 1) establishing a baseline risk number and 2) calculating risk spending efficiency (RSE) for the applicable programs that mitigate a particular risk between the 2025-2028 period. In addition to providing more detail and discussion on those two key components in this section, SCE also discusses other corollary issues related to the risk calculation, including risk tranching and foundational activities. SCE also discusses RSEs. We outline why RSEs must be viewed as one important factor among a number of important factors that the utility leadership considers when engaged in its balanced and risk-*informed* decision-making process, rather than a "trump card" factor that in and of itself dictates the decision.

B. Baseline Risk Development

Establishing a risk baseline is a critical step in the RSE process, as it establishes a starting point from which risk reduction can be calculated. The method for calculating the risk baseline for the 2022 RAMP is broken down into two steps and illustrated in Figure IV-2.

Figure IV-2
Baseline Risk Calculation Methodology



Step 1 involves calculating a "Pre-baseline" risk score at the end of 2021. The risk driver frequency and consequences may be informed by historical data. There may also be variances for certain risks where historical data is not available or is inconsistent. As such, each RAMP chapter contains a discussion on the data sources used to populate the risk bowtie. This information is also provided in workpapers.

In SCE's Pre-Filing RAMP Workshop (which occurred in early December 2021), SCE stated that it would use a pre-baseline risk score that was current as of the end of 2020. SCE stated that using an end-of-2020 baseline was consistent with the information available at the time of the Pre-Filing RAMP Workshop, since 2021 had not yet ended. Now, as shown above, SCE has been able to update the risk scores to reflect additional data from calendar year 2021.

Step 2 involved modeling the proposed mitigations and their associated scope to arrive at a "Re-Baseline" at the end of 2024. From this Re-Baseline, SCE develops its risk reduction and RSE estimates for year 2025. Subsequent year RSEs (e.g., 2026 and onwards) use the baseline from the previous year as the starting point for risk reduction calculations for those years. SCE does not calculate RSEs for years outside of the RAMP analysis period (2025-2028). However, programs deployed between 2022-2024 that have multi-year benefits that may stretch through the RAMP period are carried over by adjusting the baseline risk score accordingly.

C. Tranching

In each RAMP chapter, SCE discusses the rationale of how each RAMP Risk was disaggregated into tranches. "Tranching" in this context refers to breaking down each RAMP Risk into logical sub-parts and performing separate risk analysis for each sub-part to estimate risk spend efficiency. Using risk tranches is a requirement of the S-MAP Settlement.[9]

Each tranche can be considered a "mini bowtie," with its own set of drivers, outcomes/consequences, and exposure representative of the risk characteristics of the particular tranche. For example, in the Employee Safety chapter, SCE divided the risk into three tranches. Each tranche has the same number of risk drivers, but the frequency of each risk-driver is different amongst the tranches. This reflects the different risk profile associated with each tranche. In addition, the exposure is different amongst all three tranches, reflecting the different populations associated with each of the tranches (e.g., the number of office employees vs. the number of field employees). In situations where a tranche is modeled at the most granular level, the outcome/consequence framework turns into a consequence-only approach. This means that a particular asset (e.g., a pole) would have a direct consequence associated with it, instead of multiple outcomes and consequences via the mini bowtie framework.

D. Risk Spend Efficiency

1. Introduction

The RSE calculation provides an indicator of the program's risk reduction compared to the costs for that program. The RSE is calculated based on those programs that have a direct impact on risk driver and/or consequence reduction. By itself, a single RSE score provides little intuitive value. It does not, for example, communicate whether the score represents a 'high' or 'low' RSE. The RSE for a mitigation should be considered in comparison to the RSEs of the other mitigations for that particular RAMP Risk. In this way, the RSE provides one perspective regarding the relative spending efficiency of one mitigation for the RAMP Risk compared to other mitigations for that same RAMP Risk. However, an RSE has limitations. It does not address or encompass a number of other crucial factors that SCE

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[9] The S-MAP Settlement uses the term "tranching."

must take into account as part of a prudent mitigation selection process. This is discussed in greater detail below, as well as in the Overview chapter.

The next portion of this section focuses on the inputs to an RSE calculation, and the process of calculating an RSE.

2. <u>Inputs</u>

a) <u>Mitigation Effectiveness</u>

A program's effectiveness, ranging from 0 – 100%, is determined for each risk driver and for each attribute on the consequence side. A mitigation can be effective at addressing the likelihood of a risk event, the consequence, or both. The effectiveness of mitigations are based on data, engineering analysis, field experience, subject matter expertise, as well as other sources of information. SCE documents the rationale for how the mitigation effectiveness numbers were calculated in workpapers for each RAMP Risk chapter.

b) <u>Useful Life</u>

A mitigation's useful life is the benefit stream measured in the number of years. This component can be informed by sources such as the manufacturer's claims or warranties, depreciation schedules, contractual terms, or appropriate SME judgement. For example, vegetation trimming has a useful life of one year, given that vegetation grows back each year. Trimming is required in the subsequent year as a result. This is in contrast to capital-based work, such as installing Covered Conductor -- for Covered Conductor, the Effective Useful Life (EUL) is approximately 45 years. A program's EUL can have a meaningful impact on the total risk benefits accrued by a program. The EUL benefit stream is discounted in accordance with the S-MAP Settlement.

As noted earlier, SCE's consequence attributes include safety, reliability and financial. The safety benefit is measured in the estimated number of fatalities and serious injuries avoided. These benefits are not simply fungible dollars, but represent human lives. Solely for purposes of the RSE analysis in this RAMP report, SCE has chosen to use a 3% discount rate for the benefit stream. SCE selected this rate based on Commission Decision 19-05-019, which prescribed a societal discount rate as part of a cost-benefit framework for evaluating distributed energy resources. SCE used the same discount rate for the other consequences (reliability and financial) for consistency and ease of understanding.

c) Cost Estimates

SCE has developed preliminary cost estimates for the 2025-2028 RAMP period for all controls and mitigations. These costs include both capital and O&M, and are presented in nominal dollars. It is important to note that these costs are simply estimates at a point in time. Using reasonable efforts, SCE developed these estimated costs based on the information that was reasonably available when this RAMP Report was prepared. We anticipate providing updated and more refined cost estimates in our Test Year 2025 GRC forecasts.

For purposes of RSE analysis, and in compliance with S-MAP guidelines, nominal costs are discounted by 10%, which is SCE's incremental cost of capital. Costs are discounted to 2025, which is considered Year 0 for purposes of this calculation, as that year is the first year of the RAMP analysis period.

3. Illustrative Example

a) Calculating Baseline Risk (Pre-mitigated risk score)

Table IV-4
Baseline Risk Calculation

LoRE	
Risk Driver	**Freq.**
Driver-A	10
Driver-B	10
Driver-C	20
Driver-D	10
Total	**50**

CoRE (MARS units)		
Safety	**Reliability**	**Financial**
5	5	10

Sample CoRE calculation was provided in Section II above.

$$Risk\ Score_{Pre-mitigated} = LoRE \times CoRE = 50 \times (5 + 5 + 10) = 1{,}000$$

b) <u>Applying Program's Mitigation Effectiveness</u>

In this example, the mitigation program only addresses two of the four risk drivers (Driver-C and Driver D), each of which has different levels of effectiveness.

Table IV-5
Mitigation Applied to Baseline Risk

Baseline		Post-Mitigation	
Risk Driver	**Freq**	**Program Effectiveness**	**Remaining Freq**
Driver-A	10	0%	10
Driver-B	10	0%	10
Driver-C	20	25%	15
Driver-D	10	50%	5
Total	**50**		**40**

$$Risk\ Score_{Post-mitigated} = 40\ \times (5 + 5 + 10) = 800$$

To calculate the post-mitigated score, SCE multiplied the new LoRE (40) with the same CoRE (as previously illustrated), since the mitigation program only impacted the risk drivers and not the consequences.

c) <u>Risk Reduction Calculation</u>

$$Risk\ Reduction = Risk\ Score_{Pre-mitigated} - Risk\ Score_{Post-mitigated}$$

$$Risk\ Reduction = 1{,}000 - 800 = 200$$

d) <u>Benefit Stream</u>

Assuming a 5-year useful life for this program, the Net Present Value (NPV) calculation is illustrated below, using a 3% discount rate:

Non-Discounted Benefit Stream

Year 0	Year 1	Year 2	Year 3	Year 4
200	200	200	200	200

Discounted Benefit Stream

Year 0	Year 1	Year 2	Year 3	Year 4
200	194	189	183	178

The discounted benefit stream total is ~943.

e) RSE final calculation

Estimated Cost (discounted to 2025) = $5 million

$$RSE = \frac{Discounted\ Benefits}{Estimated\ Cost\ ('000)} = \frac{943}{\$5{,}000} = 0.1886$$

SCE applied a final readability multiplier of 10,000,000 to the RSE calculated above to arrive at a final number of 1,886,000.

4. Discussion on Estimated RSE Metrics

Overlapping mitigations – The estimated RSEs calculated in this report are independently calculated from other mitigations, meaning they do not take into account the potential operational efficiencies gained from combining multiple mitigations together. This allows a like-for-like comparison of mitigation RSEs against one another.

Computing an RSE that combines multiple mitigations together would require establishing a “loading order” of mitigations, and then quantifying the risk reduction and/or cost overlaps for all the different combination of mitigation program activities. This “loading order” can be viewed as a sequential evaluation of mitigation deployment, where given a set of mitigations on a particular asset, one has to pre-determine, for risk calculation purposes, which mitigation is applied first, second, and so forth. The order has a significant impact on which mitigation program gets a higher absolute portion of the risk reduction, and may potentially skew RSE estimates.

In the case of Wildfire, SCE is in the process of conducting a deep-dive analysis regarding how long-lived system-hardening initiatives such as undergrounding may reduce the need for vegetation work. We currently expect that this analysis will inform our risk analysis in the upcoming 2025 GRC. In the case of other RAMP Risks, the sequential ordering of mitigations on a particular risk driver / tranche is not readily apparent. For example, there may be multiple training programs proposed to address a particular risk driver or tranche. The "sequential" ordering could run the gamut of multiple scenarios, from time-based (e.g., one is deployed in January vs. the other mitigation is deployed in March of the same year), or cost-based, or based on risk reduction, etc.

SCE welcomes the opportunity to discuss these challenges in future workshops or technical working group sessions in the Risk OIR. As fundamental as RSEs are to the RAMP filing, SCE stresses that RSEs themselves are an estimate based on a wide range of assumptions. As such, they are only one factor that must be considered when utility management is engaged in a prudent decision-making process. Please refer to the Overview chapter for further details.

Uncertainty in RSE estimates - The RSE estimate itself is a directional estimate, and should not be judged from a purely quantitative stand point. This is primarily due to the inherent uncertainty in the inputs. The RSE calculation is based on multiple variables, such as the estimated spend, the useful life, and the projected effectiveness of a mitigation activity. SCE strives to use internal data where possible, supplemented by external data/benchmarks and informed by appropriate SME judgment. Some mitigation programs lend themselves to a more data-driven estimate, particularly those mitigation activities which are more mature. Other mitigation activities may require many more years of data to reduce the uncertainty regarding the effectiveness of those mitigations in mitigating risk.

SCE has identified and carried out methods to help reduce the uncertainties in these estimates, including the following: 1) Conducting working sessions with SMEs to assess and document mitigation effectiveness, and foster mitigation effectiveness being informed by engineering standards (such as the standards applicable to the Seismic and Hydro Dam Failure RAMP Risks; 2) Calibrating mitigation effectiveness across different activities that mitigate the same risk, to achieve a relative degree of consistency; 3) Conducting in-depth challenge sessions with SMEs and risk management professionals to review inputs and assumptions; and 4) In certain cases, collaborating with other utilities to further refine mitigation effectiveness assumptions. (One such example is the Joint IOU Covered Conductor Effectiveness Working Group, as part of the Wildfire Mitigation Plan Action Statements.)

RSE cannot be sole metric to determine mitigations - RSEs, though an important and valuable input, are not, and cannot be, the only factor used to develop or execute a risk mitigation plan. Other factors include, but are not limited to: 1) Risk Drivers and Consequences Addressed (including lessons learned from other utilities or drivers that can be only addressed by other mitigations); 2) Risk Reduction; 3) Operational Feasibility / Deployment Time; 4) Cost to Customers; 5) Enabling Activity/Technology Maturity/Additional Benefits; 6) Compliance/Regulatory Guidance; and 7) Resource Availability.

RSEs do help SCE evaluate the relative cost-effectiveness of potential mitigation initiatives and, in turn, may provide additional insight concerning prudently allocating resources, funding, and efforts to mitigate the risk. But RSEs may not reflect certain operational realities. For example, PSPS may appear to have a strong risk spend efficiency, largely because there are relatively minimal direct financial costs to the utility of implementing the mitigation. And its effectiveness is high because it involves shutting off the power entirely. However, there are substantial reliability and other impacts to the customers and communities affected, and there are regulatory and practical limits to how much PSPS can and should be deployed. Indeed, the Commission has stated that PSPS should only be used "as a last resort."[10]

As a general matter, SCE's proposed mitigation plans balance activities that should collectively and prudently reduce risk in a reasonable amount of time, when one considers not just RSEs but important regulatory, operational, resource, and cost factors and constraints as well. The preliminary

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[10] D.21-06-034 at p. 17, *citing* D.19-05-042, Appendix A at A1; D. 20-05-051, Appendix A at p. 9.

risk estimates in RAMP can change as the analysis is further refined and updated in connection with our upcoming Test Year 2025 GRC.

E. Foundational, Compliance, Controls and Mitigation Activities

Foundational Activities – As part of the Risk-Based Decision-Making Framework (R.20-07-013), the Commission issued a Decision (D.21-11-009) that addresses the treatment of foundational activities in RAMP. Foundational activities are defined as "initiatives that support or enable two or more mitigation programs or two or more risks, but do not directly reduce the consequences or reduce the likelihood of safety risk events." RSE calculations for foundational activities are not required.[11] However the estimated budget, subject to certain thresholds, should be incorporated into the mitigation programs that the foundational activities enable. As part of its RAMP filing, SCE has identified those programs which meet this definition. Unless otherwise indicated, SCE allocates the costs of these activities based on a proportional cost of the mitigation programs they enable.

For example, consider two mitigation programs with the following costs: Mitigation A is $50, and Mitigation B is $100. A foundational activity that enables both Mitigation A and B would have an estimated cost of $60. SCE would allocate $20 of the foundational activity cost towards Mitigation A and $40 towards Mitigation B, based on a proportional cost calculation.

Compliance Activities – In the Risk OIR and other regulatory forums, SCE has consistently taken the position that calculating an RSE score for compliance-based work is not a productive endeavor, because SCE does not have the option to pick and choose which laws to follow or not follow. In propounding laws, the Legislature takes testimony from various sources (including experts), enters documentary material into the record, and carefully balances various critical interests and studies with regard to the best way to carry out the intent the Legislature has in compelling adherence to the law. It is not the utility's place to, in essence, try to second-guess the Legislature by assigning relative and ranked values of complying with different laws and sources of binding authority.

[11] D.21-11-009, Ordering Paragraph 1e, p. 11.

Assigning relative values for purposes of comparison is the central point of an RSE exercise, but it is only applicable to activities where the utility has some meaningful ability to choose one activity versus another. This option to implement or not implement is absent when the utility must undertake the activity in order to comply with laws, regulations, or judicial mandates. SCE cannot choose a non-compliance path, or select partial compliance.

In D.21-11-009, the Commission directed the IOUs collectively to work together to come up with uniform working definitions of controls (and also, if necessary, mitigations as well).[12] SCE believes that it provides RSEs for controls and mitigations in a manner generally consistent with the other IOUs, and in conformance with applicable Commission guidance. In light of the time constraints and commitment of resources needed to prepare and file a timely and compliant 2022 RAMP report, SCE plans to continue to collaborate with the other IOUs following our RAMP filing, in an effort to seek additional consistency among the IOUs. For purposes of this RAMP filing, SCE has defined three categories of programs, 1) Compliance Activities, 2) Controls and 3) Mitigations.

Compliance activities are those activities that are required by law or regulation. Some examples include activities that support Federal or State OSHA requirements, FERC orders and requirements for hydro facilities, and Commission General Orders (GO). For each risk, SCE will identify those activities that are Compliance activities, and cite the relevant statutory law or regulation.

Per D.21-11-009, RSEs are required for all controls and mitigations. SCE defines these categories as follows:

<u>Controls</u> – SCE defines a control as an activity that was undertaken prior to 2021 to address the RAMP Risk, and which may continue through the RAMP period. The controls are designated with a "C," and then followed by an identifying number (e.g., C1 is Control Number 1 for the RAMP Risk). RSEs will be calculated for controls.

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[12] *See,* D.21-11-009, Ordering Paragraph 1.a, p. 140.

Mitigations – SCE defines a mitigation as an activity commencing in 2021 or later to address a particular RAMP Risk. They are designated with a "M" and then followed by a number (e.g., M1 is Mitigation Number 1 for the RAMP Risk). RSEs will be calculated for mitigations.

V.

WORKPAPERS

For each RAMP chapter, SCE provides workpapers describing the data sources leveraged, rationale and/or methodology associated with the baseline risk numbers, and mitigation inputs. Excel models used to calculate RSEs are also provided for each risk. For risks where Excel is not a feasible solution to handle the complexities and the level of granularity required to calculate RSEs at the tranche level, SCE will provide a summary overview of the model used to calculate the RSE. This will include a discussion on the methodology used to estimate the probability and consequences for those risks. A data file that includes RSEs at the tranche level will also be provided on SCE's website.[13]

Pursuant to D.21-11-009, SCE will "test drive" PG&E's Transparency Proposal (as raised in the Commission's Risk-Informed Decision-Making Rulemaking). SCE plans to submit the results of the "test drive" as supplemental workpapers no later than 60 days after SCE files its RAMP. Please note that the Commission has expressly directed that the results of the SCE "test drive" are to be shared *solely for informational purposes*.[14] As part of its reporting on the results, SCE will also document any challenges associated with this endeavor, and will suggest possible alternatives if applicable.

VI.

ADDRESSING FEEDBACK

TURN provided feedback during the Pre-filing RAMP workshop regarding the implied value of statistical life (VSL) in SCE's MAVF; TURN suggested changing the Safety range to 1000 instead of 100.

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[13] *See* https://www.sce.com/regulatory/CPUC-Open-Proceedings.

[14] *See* D.21-11-009, p. 133, Finding of Fact Number 11.

SCE responded as follows: SCE's development of the MAVF complies with the S-MAP Settlement guidelines. The topic of VSL and other matters pertaining to MAVF development is already designated as a topic to be taken up in Phase II the Risk-Based Decision Making Framework Rulemaking (R.20-07-013).

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Safety Culture, Organizational Structure, Executive and Utility Board Engagement, And Compensation Policies Related to Safety

Chapter 3

Rosemead CA
May 13, 2022

Chapter 3: Safety Culture, Organizational Structure, Executive and Utility Board Engagement, and Compensation Policies Related to Safety

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I.

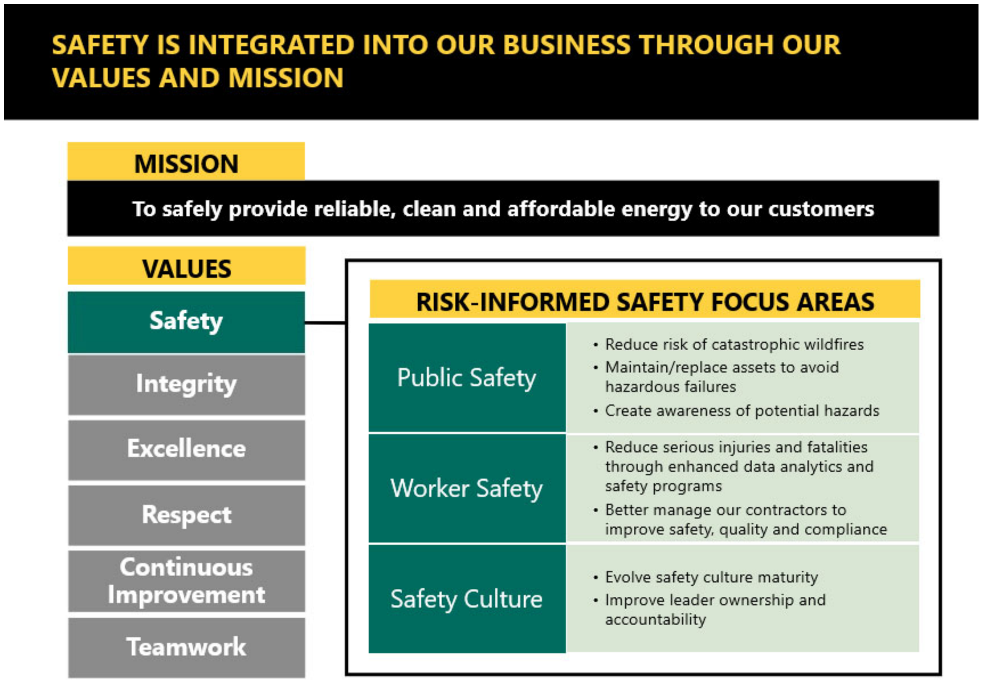
EXECUTIVE SUMMARY

This chapter describes SCE's safety culture and performance, safety organizational structure, executive and senior management engagement, board engagement, and compensation policies related to safety.[1]

As shown below in Figure I-1, safety is integrated into our business through our core values and vision. SCE is committed to delivering safe, reliable, affordable, and clean energy to its customers. Safety is our number one value, and part of that is making sure that we empower employees with the knowledge, motivation, and means to make safe choices. SCE is also committed to collaborating with our contractors to strengthen safe work practices, and educating the public to avoid hazards associated with our electrical grid.

[1] Inclusion of Safety Culture and Organizational Structure in RAMP Filings, D.18-12-014, p. 35 and D.16-08-018 at 140-142.

Figure I-1
Safety is SCE's # 1 Value



II.

SAFETY CULTURE AND PERFORMANCE

A. Safety Performance

Safety is a core value at SCE. Our safety objectives are to strengthen our safety culture, eliminate serious injuries and fatalities (SIF) to the public and to our workers, and continue to make efforts to reduce injuries with the ultimate goal of achieving an injury-free workplace. In some performance areas, SCE has seen a dramatic improvement in its safety results. However, SCE recognizes that it has more work ahead to ultimately achieve and maintain a fully mature safety culture, foster an injury-free workplace, and protect members of the public.

1. Public Safety

Through various mechanisms, we strive to bring awareness to the public about our system, while in parallel taking opportunities to protect customers in our service area from potentially adverse outcomes. Table II-1 outlines the trend of public serious injuries and fatalities reported to the Commission from 2014 through December 2021.

Table II-1
Historical Public Serious Injuries and Fatalities

Public Serious Injuries & Fatalities due to system failures

	2014	2015	2016	2017	2018	2019	2020	2021
Public Fatalities due to system failure	0	0	0	1	0	0	0	0
Public Serious Injuries due to system failure	0	0	0	1	0	1	1	0

Total Public Serious Injuries & Fatalities reported to the CPUC

	2014	2015	2016	2017	2018	2019	2020	2021
Public Fatalities	11	4	6	4	9	2	2	4
Public Serious Injuries (Cal OSHA)	19	12	8	10	11	10	10	5

Using a multi-pronged approach, SCE addresses public safety in three distinctive ways. During the course of maintaining and inspecting our infrastructure, we leverage controls and mitigations to help mitigate the risk of system failure contributing to a public safety incident. In Chapter 5, Contact with Energized Equipment and Chapter 6, Underground Equipment Failure (UEF), examples of this can be seen through deployment of the Overhead Conductor Program (OCP) and Covered Pressure Relief Restraint (CPRR) program.

Outward-facing actions around public safety come in the form of various outreach and awareness programs. Through these communications to the public, both in the form of mass marketing and targeted outreach, we strive to deliver essential information across a plethora of platforms, to people of various ages, at-risk workers,[2] and the diverse population of our service area (through translation into

[2] At-risk workers are defined as those who may not have been properly trained to work in close proximity to power lines.

multiple languages). Chapter 4, Wildfire and PSPS, provides additional examples of the types of communication we deploy during emergent conditions.

2. Employee Safety

SCE has established numerous safety programs and initiatives designed to maintain and improve employee safety. The Edison Safety and Enterprise Risk Management (ERM) organizations provide guidance, governance, and oversight of the Company's safety programs and activities focused on public, contractor, and employee safety. This includes developing and managing programs to meet requirements outlined by governing regulatory agencies, including the Occupational Safety and Health Administration (OSHA) and the California Division of Occupational Safety and Health (Cal/OSHA). Our activities also encompass learning from safety incident evaluations, tracking and analyzing the Company's safety data and records, managing and implementing SCE's Safety Culture Transformation, as well as managing all other employee (field and office) and contractor safety programs and standards.

Since 2012, SCE has achieved more than a 40% improvement in employee safety performance, as measured by our Employee Days Away, Restricted or Transferred (DART) Rate and the Edison Electric Institute (EEI) SIF Rate, as depicted below in Figure II-2. Additional information on SCE's efforts to reduce employee injuries and fatalities can be found in the Employee Safety RAMP chapter and in our Annual Safety Performance Metrics (SPM) report.[3]

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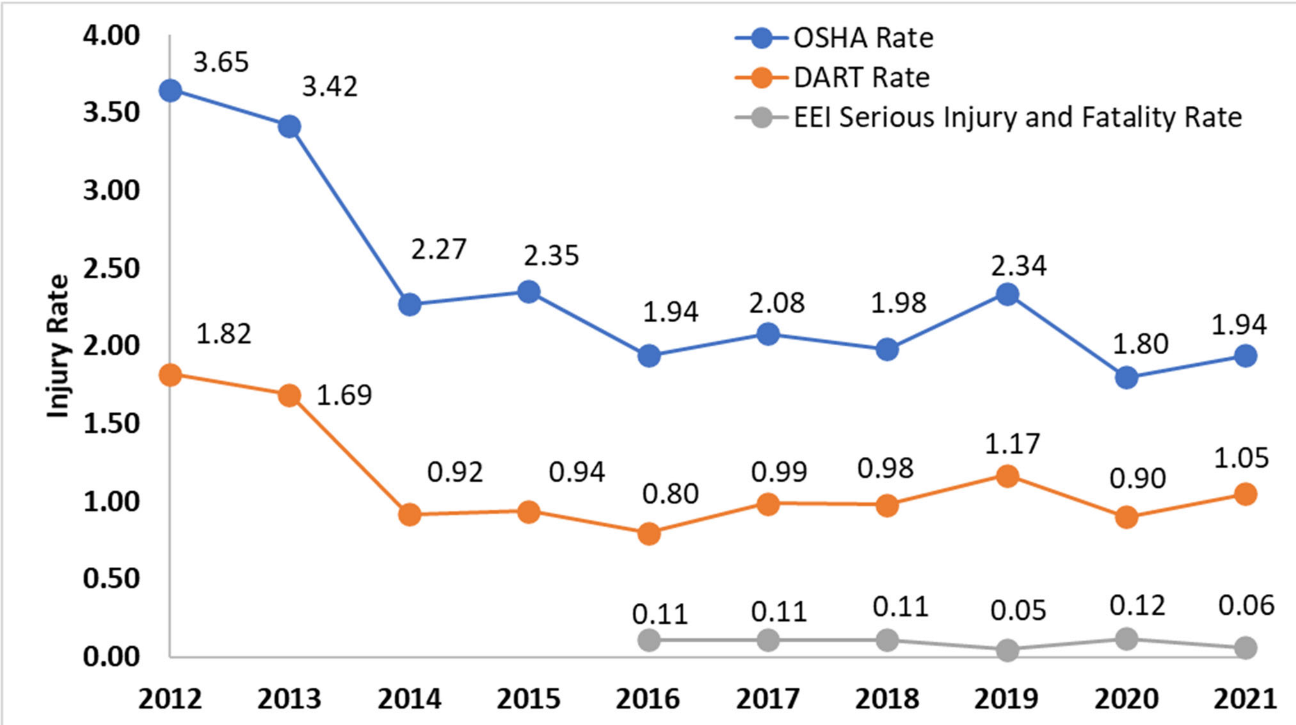
[3] *See* Chapter 9 - Employee Safety and SCE's annual SPM Reports accessible at https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/safety-performance-metrics-reports.

Figure II-2
SCE Employee OSHA, DART and EEI Serious Injury & Fatality Rates

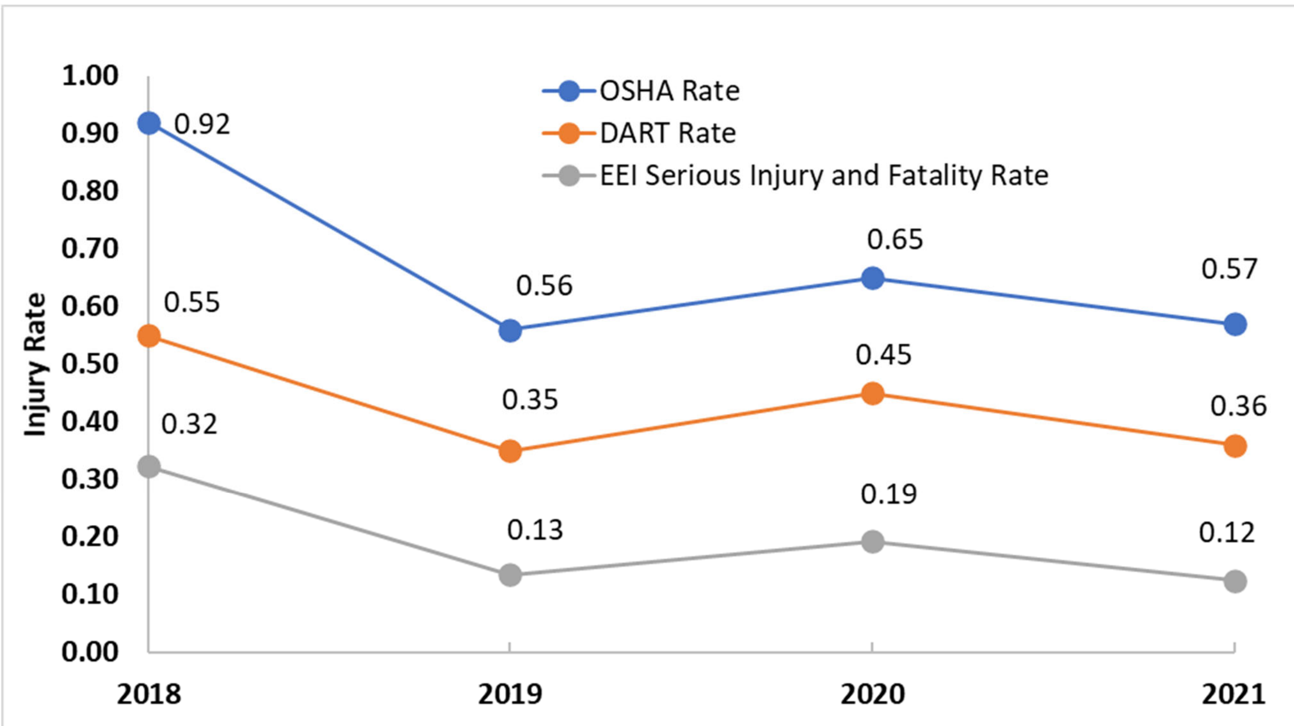


3. **<u>Contractor Safety</u>**

SCE contractors perform a variety of work, including certain high-hazard tasks that SCE does not regularly perform through its own employees. Some examples of the work performed by SCE contractors include transmission and distribution line construction, vegetation management, hazard tree removal, crane operations, traffic control, helicopter operation, drone operations, civil operations (horizontal directional drilling and jack and bore), substation operation and maintenance, generation maintenance, heavy civil equipment operation, environmental monitoring, materials transportation, and certain corporate real estate tasks.

SCE continues to utilize contractors for the work listed above, and the overall contractor hours have grown from 16.7 million hours in 2018 to 22.5 million hours in 2021. This steady increase in contractor workload represents an increased risk for SCE and is expected to continue in the foreseeable future. Figure II-3 below shows that despite the significant increase in contractor hours and the increase in absolute SIF counts, the EEI SIF *rate* has decreased by 62% since 2018. SCE has also observed a downward trend in both OSHA and DART rates for contractors. Additional information on SCE's efforts to reduce contractor injuries and fatalities can be found in the Contractor Safety RAMP chapter and in our annual SPM report.[4]

Figure II-3
SCE Contractor OSHA, DART and EEI Serious Injury & Fatality Rates



B. <u>Evolution of SCE Safety Culture:</u>

In 2018, Edison Safety began implementing its Safety Culture Transformation efforts. Transformation efforts were driven by safety culture training for all Company employees to foster a safety ownership mindset, where employees make safety choices to protect themselves and for who and what they value. SCE's Safety Culture Transformation is foundational to achieving our overarching mission of eliminating serious injuries and fatalities, strengthening safety culture, and reducing lesser

4 *See* Chapter 10- Contractor Safety and SCE's annual SPM Reports accessible at https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/safety-performance-metrics-reports.

injuries as well. Our safety performance improvement efforts will also rely on more refined use of safety metrics and data to foster a learning organization and drive targeted improvement actions.

In 2018, Edison Safety created a dashboard for employee, contractor, and public safety to better facilitate a holistic definition of safety, and to equip line leaders with the tools necessary to drive safety performance improvement. SCE's 2019 efforts focused on creating and expanding additional dashboard views, and implementing an organizational change management strategy to ensure leaders are using the dashboard to drive informed safety decisions.

As SCE seeks to anchor our safety culture maturity in Private Compliance - where all employees adopt and demonstrate a safety ownership mindset - our efforts will continue to focus on improving leaders' safety ownership. This was cited as our top area of opportunity in the 2020 SCE Safety Culture Assessment. We have set the foundation for a shared safety mindset and have equipped leaders and employees with applicable skills and tools through our extensive safety culture training efforts. Our path forward is focused on fully embedding SCE's safety culture in Private Compliance - where leaders are accountable for safety culture improvements and safety outcomes, and employees consistently demonstrate safe behaviors.

Based on the results of our upcoming 2023 Safety Culture Assessment, we will refine our Safety Culture Transformation efforts to implement initiatives that evolve our safety culture to the Stewardship level of safety culture maturity. At this stage, all employees collectively engage in and reinforce making safe choices and consistently demonstrate safe behaviors. SCE attaining a Stewardship level of safety culture maturity builds on our foundation of Private Compliance, and is embodied by employees proactively sharing knowledge of hazards and learnings through increased trust and shared safety ownership. There should be increased cross-functional safety ownership and a strong proactive approach to learning, where employees go above and beyond to identify and mitigate exposures, especially as may be associated serious injuries and fatalities. Employees govern themselves and hold each other accountable for safety outcomes.

Table II-2
Safety Culture Focus Areas and Initiatives

Safety Culture Focus Areas	Initiatives
Leader Safety Ownership & Accountability	• Safety Commitment and Planning Workshops spanning executive to front line leaders to prioritize safety culture assessment themes and build contextualized OU-specific plans to address triennial assessment findings • Cognitive-behavioral leader safety ownership playbook to build on tools and concepts provided in Safety Culture Training • Leader field engagement to reinforce safety mindset and behaviors • Paired safety observation program for frontline leaders to develop coaching and recognition skillset to improve risk identification and mitigation • Coaching for front line leaders to further embed skillset and tools to sustain a psychologically safety work environment where workers speak up
Safety Culture Measurement	• Quarterly safety culture pulse facilitating increased measurement of leader safety engagement and ownership • Triennial Safety Culture Assessment that measures progress along our safety culture maturity model • Measure impact of safety culture on safety metrics
Employee Engagement Safety Ownership & Participation	• Enterprise-wide program to submit grassroots safety projects that drive continuous safety improvements • Conduct safety Kaizens with front line employees to develop and implement mitigations for high hazard risks • Conduct safety recognition event facilitated by SCE's CEO for employees who demonstrated significant safety engagement and ownership
Safety Culture Training Sustainment	• Safety culture micro-learnings to provide leaders with ongoing refreshers of core safety leader skills and tools to sustain a strong safety culture • Cognitive behavioral leader safety ownership playbook to take specific actions using tools provided in safety culture training • Safety culture micro-learnings to reinforce safety culture concepts and tools to sustain worker safety attitudes and behaviors

III.

SAFETY ORGANIZATIONAL STRUCTURE

A. Edison Safety

On October 1, 2018, SCE created the Edison Safety organization as depicted in Figure III-4. This organization is led by the Vice President of Safety, Security and Business Resiliency. The organization consolidated several existing safety organizations across Transmission and Distribution, Generation, Customer Service, Operational Services, and Corporate Health and Safety. Edison Safety provides guidance, governance, and oversight of SCE's safety programs and efforts. This includes contractor and employee safety efforts to eliminate serious injuries and fatalities, strengthen safety culture, and reduce all injuries.

Edison Safety is responsible for developing and managing programs that meet requirements outlined by OSHA and Cal/OSHA, co-leading in partnership with Organizational Units (OUs) on the following:

- Evaluating major safety incidents, including serious member-of-the-public safety incidents;
- Monitoring and analyzing the Company's safety data and records;
- Managing and implementing SCE's Safety Culture Transformation; and
- Managing other employee and contractor safety programs and standards.

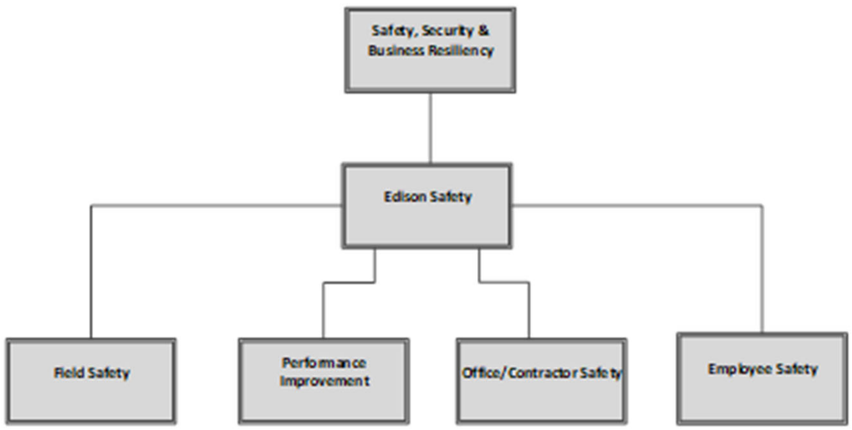
Edison Safety also partners with OUs, so that each OU's activity-specific safety programs meet applicable regulatory requirements. Edison Safety helps identify potential safety risks based on observations, incident evaluations, data collection, and analysis. Identified risks are mitigated through developing and implementing corrective actions, and maintaining safety programs and safety culture efforts informed by analyzing safety metrics as well as more broadly assessing our safety culture and safety management system.

To better drive public safety efforts through a common risk approach, SCE shifted the public safety function from Edison Safety to our ERM function. Our ERM organization[5] oversees a multi-OU

[5] The ERM organization and its role are discussed in more detail below in Section III.B.

execution model to create a common risk management framework and modeling for public safety, and provide a single source of public safety risk information to assist risk-informed decision-making across the enterprise.

Figure III-4
Edison Safety Organizational Chart



Efforts to improve SCE's safety performance and culture are centered on:

- Employee safety programs aimed at maintaining and improving employee safety;
- Employee engagement activities designed to engage workers on safety principles to create a safe work environment for employees and improve public safety; and
- Safety systems intended to address incidents and injuries, share best practices, and utilize performance metrics to support the safety culture at SCE.

B. <u>Enterprise Risk Management</u>

To protect our customers, our workers, and the communities we serve, and to continue reliable delivery of service, SCE has developed a Company-wide program that systematically identifies, evaluates, mitigates, and monitors risks. In doing so, we are able to deliberately review, discuss, and prioritize enterprise risks. Our ERM approach also incorporates risk-informed planning in the many decisions we make while serving our customers and conducting our business.

SCE's ERM organization centralizes oversight and guidance on key and emerging risks across the Company. Specifically, ERM's role is to identify the most critical risks facing the entire enterprise, validate that appropriate mitigation measures have been initiated, monitor the status of the risks and the mitigation measures, and communicate ERM's findings concerning key and emerging risks to SCE's senior management and Board of Directors (wildfire and PSPS risks are two of the most critical risks utilizing this ERM approach).

Edison International's Board of Directors has broad responsibility for the oversight of significant risks, including those related to strategy, operations, finance, and reputation. The Board actively reviews our ERM process and monitors significant risks. The Board exercises this responsibility through direct engagement with management and through its committees, which regularly report back to the Board. The Audit and Finance Committee provides oversight of ERM's risk assessment report (an annual review of significant risks, classified into three tiers: key, secondary and emerging), as well as financial reporting risk. The Safety and Operations Committee provides oversight of emergent operational risks and operational mitigation of risks.

ERM works closely with each OU through a "hub-and-spoke" structure to manage risk across the Company. ERM establishes SCE's common risk management framework. ERM also facilitates cross-OU collaboration in developing and maintaining consistent and coherent risk management tools and systems. The OUs provide data, analysis, and guidance on the risks as found within each OU. This helps ERM prioritize and manage the key risks across the Company. Throughout the year, ERM meets with senior leaders to review and discuss enterprise- and operational-level risks and mitigation plans.

SCE's risk-informed decision-making framework is built on the foundation we described in SCE's 2015 Safety Model Assessment Proceeding (SMAP) Application.[6] In the succeeding years, SCE has taken measured and prudent steps to enhance our risk management capabilities. SCE has benefitted from actively participating in the Wildfire Mitigation Plan (WMP), SMAP, and RAMP processes,[7] and collaborating with the Commission's Wildfire Safety Division, Safety Enforcement Division, the Public Advocates Office, intervenors, and other California utilities in a host of risk-related proceedings and

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6 A.15-05-002, SCE's Safety Model Assessment Proceeding application, submitted May 2015.

7 ERM serves as the lead organization for SCE in RAMP, SMAP, and other risk-related proceedings.

forums. In risk-oriented proceedings, the Commission has repeatedly noted that risk analysis and risk-informed decision-making is an evolving arena.[8] SCE continues to mature our processes to identify, review, and approve new or modified mitigation initiatives in a manner that supports an increasingly consistent assessment framework. This framework helps ensure that proposed mitigations provide measurable risk buy-down for purposes of eliminating or reducing key risks, and can be successfully placed into an executable plan.

IV.

EXECUTIVE AND SENIOR MANAGEMENT ENGAGEMENT

A. Structured Senior Management Engagement on Safety

Throughout the year, the ERM group meets with senior leaders to review and discuss enterprise- and operational-level risks and mitigation plans. SCE senior leadership plays a critical role in establishing a strong risk assessment culture across the Company. Our senior leaders actively engage with ERM efforts, encourage leaders and subject matter experts (SMEs) throughout the Company to participate in the risk assessment process, and make such risk-related efforts one of the Company-wide continuous improvement priorities. This support has enabled the ERM group to develop, establish, and implement a more consistent and structured risk-informed decision-making framework.

SCE has a Finance and Risk Management (FRM) Committee. This committee is chaired by the SCE Chief Financial Officer (CFO), and consists of the SCE General Counsel and the Senior Vice President (SVP) of Regulatory Affairs as voting members. The SCE Chief Executive Officer (CEO) and President actively participate in FRM Committee meetings.[9] The purpose of this committee is to: (1) oversee and approve the allocation of SCE's financial resources, energy procurement activities, and enterprise-wide risk management; and (2) provide a forum and a process to identify, understand, manage, and mitigate critical risks related to these areas, in accordance with regulatory directives and Company policies. On rare occasions, when the scope, scale, and exposure to a risk is large enough

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8 *See, e.g.*, D.16-08-018, Finding of Fact 35 ("There is no optimization of portfolio of risk mitigation activities, but this will take several more years of evolving utility models, data collection, and assessments.").

9 Approval from the CEO is required when matters exceed certain cost or impact thresholds.

(e.g., catastrophic wildfire), SCE may introduce an additional decision-making body (which contains all the aforementioned members).

The leadership team at SCE's parent company, Edison International (EIX), has established an Executive Management Committee (EIX EMC) that oversees SCE's risk management program and enterprise risks. The EIX EMC is chaired by the EIX CFO, and its membership includes the EIX CEO, EIX General Counsel, EIX SVP of Strategy and Corporate Development, and the EIX Vice President of Enterprise Risk Management and Insurance and General Auditor (EIX VP of Risk Management) as a participant. The SCE CEO, CFO, and General Counsel also participate in matters involving SCE risks.

The EIX EMC is responsible for reviewing and understanding critical risks facing SCE. The EIX EMC reviews and approves the annual enterprise risk assessment and mitigation plans. EIX leadership is also responsible for fostering a corporate-wide culture that makes identifying, analyzing, managing, mitigating, and reporting risks an integral part of corporate strategy and operations. Similar to SCE, on rare occasions for specific risk exposures, EIX may also introduce an additional decision-making body which contains all the aforementioned members and has explicit authorization to make risk-specific decisions on EIX's behalf.

Through these various executive committees and forums, oversight of SCE's ERM program is provided at all levels of the Company. The oversight of enterprise risks includes the following:

- EIX and SCE Board of Directors, Audit Committees of the Boards of Directors, and EIX EMC;
- SCE senior management including the SCE CEO, President, CFO, the General Counsel, and FRM Committee;
- EIX VP of Risk Management, who reports to the EIX CFO;
- SCE senior leaders who manage OU risks across the Company;
- SCE's Director of Risk Management, who reports to the EIX VP of Risk Management;
- SCE's Principal Managers of ERM, who report to SCE's Director of Risk Management; and
- Risk Advisors and Senior Advisors, who report to SCE's Principal Managers in ERM.

V.

UTILITY BOARD ENGAGEMENT

A. Quarterly Notifications

Pursuant to California Public Utilities Code §8389(e)(7), electrical corporations requesting a Safety Certification are required to submit a quarterly notification (Notification) to the Office of Energy Infrastructure Safety (OEIS). The purpose of the Notification is to detail the implementation of the electrical corporation's approved WMP and recommendations of the most recent safety culture assessment, and provide a statement of the recommendations of the Board of Directors Safety Committee (SOC) meetings that occurred during the quarter. The Notification also summarizes the implementation of the Safety Committee recommendations from the electrical corporation's previous filing.[10]

The Notification summarizes the SOC meetings that occur throughout the year. These meetings have focused discussions in the areas of wildfire safety, worker safety and public safety, among other topics. In addition to quarterly meetings, the Committee Chair meets regularly with SCE management to discuss wildfire and worker safety issues. The Notification also describes the recommendations and requests made by the SOC as well as the completed and pending management responses to those recommendations.

B. Safety and Operations Committee of the Board of Directors

The SOC is made up of five independent directors, and is responsible for oversight of the Company's safety performance and culture, operational goals, safety and operational risks, and significant safety-related incidents involving employees, contractors, or members of the public. The OC maintains joint responsibility with the full Board of Directors with respect to safety oversight at SCE.

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[10] Compliance Operational Protocols, issued February 16, 2021. https://energysafety.ca.gov/wp-content/uploads/docs/misc/wsd/2021.02.16-compliance-operational-protocols.pdf.

Figure V-5
Safety and Operations Committee Engagement with SCE Board of Directors

The SOC has the following duties and responsibilities:

1. Review and monitor the Company's safety programs, policies, and practices relating to:
    a. The Company's safety culture and risks;
    b. Significant safety-related incidents involving employees, contractors, or members of the public; and
    c. The measures and resources to prevent, mitigate, or respond to safety-related incidents.
2. Monitor the Company's safety, wildfire, and operational and service excellence performance metrics.
3. Review and monitor the Company's operations, significant developments, resources risks and risk mitigation plans relating to:
    a. Reliability, affordability and customer service;
    b. Wildfires;
    c. Cyber and physical security;
    d. Business resiliency and emergency response;
    e. Information and operational technology;

f. Climate adaptation; and

g. Decommissioning of the San Onofre Nuclear Generating Station.

4. Perform such additional functions as the Committee determines are necessary or prudent to fulfill the Committee's duties and responsibilities.

The SOC receives reports at least six times a year from SCE Leadership. The SOC Chair reports out to the full Board of Directors on key operational updates.

VI.

COMPENSATION POLICIES RELATED TO SAFETY

A. Overview of SCE's Executive Compensation Structure

SCE's executive compensation structure promotes safety as a core value, helps ensure public safety and utility financial stability, and otherwise meets (i) the requirements set forth in Public Utilities Code Sections 8389(e)(4) and 8389(e)(6); (ii) the Office of Energy Infrastructure Safety's (Energy Safety) 2022 Executive Compensation Structure Submission Guidelines (Energy Safety Guidance); and (iii) the majority of elements in Assigned Commissioner Ruling, Proposal 9 for Pacific Gas and Electric Company (PG&E).

The SCE Board of Directors' Compensation and Executive Personnel Committee (Compensation Committee) determines three compensation elements each year that constitute Total Direct Compensation for our Senior Officers.[11] These three elements are base salary, annual incentive compensation, and long-term incentive (LTI) awards. Base salary is a fixed rate of income for the year. Annual incentive awards are the variable portion of market-based cash compensation, and are designed to focus attention on specific safety, operational, financial, and strategic objectives that benefit our customers and other stakeholders. LTI compensation is largely tied to underlying EIX stock

[11] The Compensation Committee determines compensation for all officers who are executive officers under Rule 3b-7 of the Securities Exchange Act of 1934 (Executive Officers). It also determines compensation for any Senior Vice Presidents who are not Executive Officers (Other Senior Officers) and reviews certain aspects of compensation for SCE's Vice Presidents who are below the level of Senior Vice President (Other Officers). The Board has delegated to the CEO the authority to determine compensation for SCE's Other Officers. This RAMP chapter focuses on the compensation structure for officers whose compensation is determined by the Compensation Committee (Senior Officers). However, the same basic compensation structure applies to the Other Officers.

performance, and promotes a focus on the Company's long-term goals and financial health, in alignment with our customers, investors and other stakeholders. LTI is offered in the form of stock options, restricted stock units, and performance shares. To effectively recruit and retain qualified executives to run the utility, the Company aligns with market practice for all three pay elements.

The structure of SCE's executive incentive compensation prioritizes and focuses on safety outcomes in a variety of ways, including reduction of annual incentive award payouts if specific safety and safety-related targets are not achieved.

SCE's 2022 annual incentive goals convey SCE's emphasis on safety by weighting Safety and Resiliency as 55% of the target award. The goals also underscore safety by including safety as a foundational goal that can result, and has resulted in some prior years, in a reduction or elimination of the annual award to executives if there is a significant lapse in safety. Performance Management and Operational Excellence is weighted at 45% and includes a system reliability success measure that impacts safety and a financial performance success measure.

For each goal category, the Company provides representative success measures. The success measures are labeled as "representative" to reflect that the Compensation Committee has discretion to adjust for real-world events. Every situation cannot be accurately contemplated in advance when annual goals and success measures are developed and established. We want executives to react in a dynamic manner to new issues as they arise, particularly in terms of safety.

When goals are established, the subcomponents that comprise goal categories are not assigned specific weights. Allocating small percentages to numerous subcomponents would mask the importance of the overarching goal categories. For example, the most important and heavily weighted category is Safety and Resiliency, which includes wildfire mitigation. Providing a weighting breakdown of subcomponents at the beginning of the year might obscure the critical importance of all the representative success measures within the category. They are all necessary in our effort to increase the safety and resiliency of our communities and our workers. We want executives, and all employees, to be focused on achieving the main objectives and all the success measures, and not make tradeoffs due to small weighting differences between subcomponents.

Each year, SCE engages in an extensive goal development process that begins in June of the prior year, with a strategic refresh of Company priorities by the Board. The process concludes in February of the goal year, when final goals and success measures are approved by the Compensation Committee. During this process, SCE reviews internal and external developments such as regulatory commitments (e.g., WMP) and guidance (e.g., Energy Safety's guidance for SCE's 2022 executive compensation structure), progress on current goals, performance gaps, budgetary issues, external factors impacting the Company, and evolving best practices. Success measures are adjusted to account for recent and historical performance, availability of internal resources, improvements in measuring performance, and other developments.

The result of this process, in terms of changes from 2021 to 2022 to the Short Term Incentive Plan (STIP)[12] and the Executive Incentive Compensation Plan (EICP),[13] was a reduction in the number of goals and success measures, the elimination of most qualitative success measures and an increase in the number of quantitative success measures (thereby making scoring more transparent), more outcome-based success measures, more alignment with WMP scope and metrics, and new goals addressing the following:

- Quality of field work (new quantitative goal to focus on quality performance in key programs);
- Customer experience (SCE replaced the Customer Service Re-platform implementation goal, since that project has been completed. Instead, we have a quantitative goal to improve Billing and Payment Net score levels); and
- Execution-focused clean energy and electrification activities (new quantitative goal to support Pathway 2045).

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12 STIP is an annual variable pay program that gives employees an opportunity to earn a cash award based on achieving Company goals. Exempt employees participating in STIP have their award amounts further adjusted based on individual performance.

13 The STIP and EICP have the same goals and success measures and the same scoring of Company performance by the Compensation Committee.

B. Role of Compensation Committee

The Compensation Committee is responsible for reviewing and determining the total compensation paid to Senior Officers. The Committee is comprised of independent Board members who have significant experience and qualifications, and bring a variety of perspectives to the Compensation Committee's deliberations. No officers or other employees serve on the Compensation Committee. The Compensation Committee retains an independent compensation consultant, Pay Governance, to assist in evaluating Senior Officer compensation, including industry trends and best practices.

In alignment with best practices, the Compensation Committee generally targets a competitive range of +/-15% around the market median for each element of Total Direct Compensation offered under our program: base salaries, annual incentive awards and long-term incentives awards. Above-median compensation usually is not needed, but the +15% end of the range provides flexibility when it is needed for individual recruitment of specialized skills, retention purposes, or to reward exceptional performers.

Below-median compensation usually is avoided, because it can create retention and recruitment difficulties. However, the -15% end of the range provides flexibility for newly-promoted executives or other circumstances where below-median compensation is appropriate for a time. The Compensation Committee exercises its judgment in setting each Senior Officer's compensation levels. Additionally, the Compensation Committee must determine the Company's overall performance related to its goals and set the Company multiplier payout percentage.

At the Compensation Committee meeting in February following the end of the goal year, the Compensation Committee assesses all the representative success measures that were approved at the beginning of the goal year, as well as other important activities and developments during the year. The Compensation Committee evaluates the relative importance of the various success measures and scores the subcategories, depending on the extent to which the goals were unmet, met or exceeded, to establish the Company multiplier payout percentage. The Compensation Committee can exercise discretion to adjust the Company multiplier, including eliminating the annual incentive award entirely, should circumstances warrant.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

WILDFIRE AND PSPS

Chapter 4

Rosemead CA
May 13, 2022

Chapter 4: Wildfire and PSPS

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Chapter 4: Wildfire and PSPS

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I.

EXECUTIVE SUMMARY

A. Risk Overview

1. Background

This chapter provides a detailed risk discussion and analysis concerning SCE's significant efforts to mitigate the risk of wildfires associated with SCE equipment, in order to help protect the safety and well-being of our customers and the communities that we serve. Our risk reporting encompasses a number of mitigations, and focuses most prominently on our principal programs to address the risk -- our Wildfire Covered Conductor Program (WCCP) and our prudent and selective undergrounding of existing overhead lines through our Targeted Undergrounding Program (TUG).

SCE provides electric service to more than 15 million people[1] in a 50,000 square-mile service territory across California's southern, central, and coastal areas. Our service area is comprised of nine regions[2] with a diverse topography, from heavily forested mountainous areas to large swaths of chaparral grassland and desert biomes (see Figure I-1 below). Fuel and weather conditions in these regions play a significant role in the initiation, spread, and intensity of wildfires. Fuel conditions (such as the age of fuels, condition and health of the fuels, and volume and type of fuels) are localized and dynamically impact wildfire risk. Similarly, weather conditions, such as wind speed and dryness of the air play a significant role in the initiation, spread, and intensity of wildfires. These factors are generally unique to a particular region.

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[1] SCE provides this service through over 5 million customer accounts.

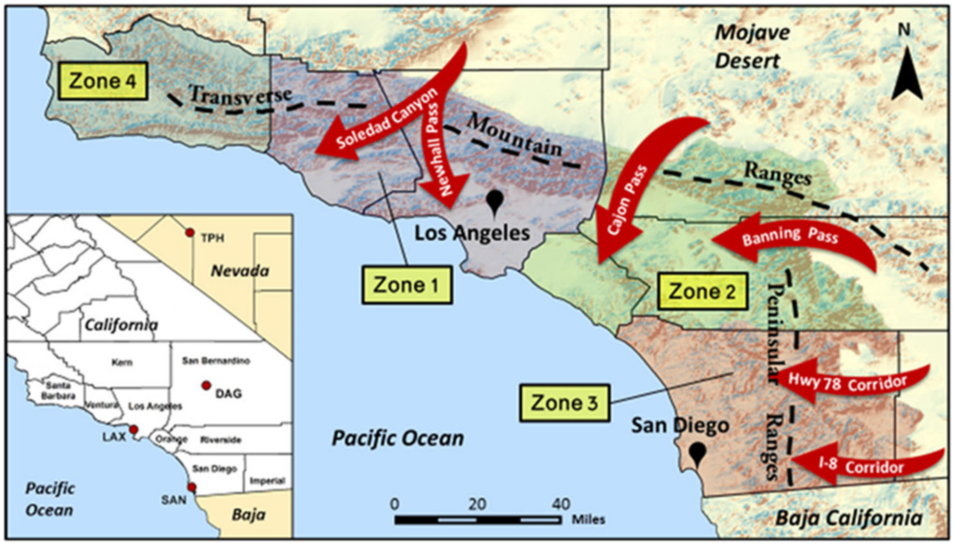
[2] SCE's nine regions are North Coast, Metro East, Metro West, San Joaquin, Orange, Rural, North Valley, Desert, and San Jacinto.

Figure I-1
California Biomes

Many of these regions experience sporadically rainy winters, and dry and hot summers. Additionally, the North Coast experiences Sundowner winds in the late Spring/early Summer, while mountain passes are subject to Santa Ana winds in the late Fall through late Winter.[3] Santa Ana winds are dense masses of air formed at higher elevations, which are compressed through mountain passes. As this compressed air flows from areas of higher pressure to lower pressure, the resulting air masses increase in speed, heating and drying plant material in their path (see Figure I-2). This unique combination of diverse vegetation types, topography, terrain, weather, and wind patterns create conditions conducive to significant wildfire events.

[3] Rolinski, Tom & Capps, Scott & Fovell, Robert & Cao, Yang & D'Agostino, Brian & Vanderburg, Steve. (2016). The Santa Ana Wildfire Threat Index: Methodology and Operational Implementation. Weather and Forecasting. 31. 10.1175/WAF-D-15-0141.1.

Figure I-2
Map of Santa Ana Wind Zones and Associated Passes



This risk of significant wildfire events continues to grow due to a range of changing climatic conditions that foster the initiation, spread, and intensity of wildfires; these developments in turn escalate the consequences of wildfires. Extreme multi-year droughts (*i.e.*, increased temperatures and decreased precipitation) continue to lead to increases in dead vegetation, while increases in the frequency and/or magnitude of wind events can compound any resulting fires.

Projections by Westerling (2018) point to a future defined by intensifying and, at times, expanding areas of elevated wildfire risk, strongly driven by changes to underlying climate conditions.[4] Other research, notably Williams, *et al*. (2019), further strengthens the primary link between climate change and wildfire activity in California.[5] While the impact of climate change in increasing the probability of utility equipment failure (*e.g*., lines-down) may not be overly significant

4 Westerling, Anthony Leroy. (University of California, Merced). 2018. Wildfire Simulations for California's Fourth Climate Change Assessment: Projecting Changes in Extreme Wildfire Events with a Warming Climate. California's Fourth Climate Change Assessment, California Energy Commission. Publication Number: CCCA4-CEC-2018- 014.

5 Williams, A. P., Abatzoglou, J. T., Gershunov, A., Guzman-Morales, J., Bishop, D. A., Balch, J. K., & Lettenmaier, D. P. (2019). Observed impacts of anthropogenic climate change on wildfire in California. Earth's Future, 7, 892–910. https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2019EF001210.

as a wildfire driver, the consequences of resulting ignitions could increase as climate change makes the underlying and surrounding landscape more receptive to ignitions.

Since the 1960s, housing patterns in California have been largely characterized by development in areas adjacent to forests, public lands, and the unbuilt environment.[6] Attracted by the appeal of enjoying open scenery and suburban living, while still being within driving distance of major economic centers of activity, people in California are moving to locations in the wildland urban interface (WUI) faster than in other parts of the country, despite the known wildfire history in these areas.[7] A recent study[8] found that 82% of the destruction and/or damages to buildings in California occurred in the WUI or Wildland Urban Intermix (WUIx) even though there was relatively less wildland fuel adjacent to these locations.

Historical wildfires, as well as wildfire simulations in these locations, have demonstrated the potential of ignitions ultimately leading to significant and destructive fires. These large fires could in turn lead to urban conflagration (a large fire that spreads beyond a natural or artificial barrier, *e.g.*, a city block). Therefore, SCE believes it is critical to include these locations in our wildfire mitigation efforts.

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6 Barrett, Kimiko (2019). Reducing Wildfire Risk in the Wildland-Urban Interface: Policy, Trends, and Solutions, 55 Idaho Law Review, No. 3.

7 Radeloff, Volker C. et al. (2018). Rapid Growth of the U.S. Wildland-Urban Interface Raises Wildfire Risk, 115 PROC. NAT'L ACAD. SCI. 3314 (2018). https://www.fs.fed.us/nrs/pubs/jrnl/2018/nrs_2018_radeloff_001.pdf.

8 Data in this study is from 1985-2013. The WUI and WUIx are defined by distinct gradients of housing density adjacent to wildland areas. Kramer, Heather et. al. (2019). High wildfire damage in interface communities in California. International Journal of Wildland Fire. 28(9): 641- https://doi.org/10.1071/WF18108.

SCE operates a total of approximately 1.4 million structures and 52,000 circuit miles of overhead conductor. Of those, approximately 300,000 structures[9] and 14,100 circuit miles[10] (27%) of overhead conductor are in High Fire Risk Areas (HFRA).[11]

Pursuant to guidance on definitions provided by the Office of Energy Safety (OEIS), there are approximately 580,000 customer accounts and 5,277 circuit miles in the WUI in SCE's service area.[12] To expeditiously reduce ignition risk, SCE deploys mitigations that complement each other in prudently addressing wildfire ignition risk drivers for SCE's overhead distribution and transmission lines. There are times when SCE initiates a Public Safety Power Shutoff (PSPS) as an ignition mitigation of last resort, in order to protect public safety under severe fire weather conditions.

In this chapter, SCE assesses both wildfire and PSPS risk in HFRA. We quantify the potential safety, reliability, and financial impacts resulting from these risks. We propose a suite of mitigations to reduce the probability of an ignition, as well as reduce the impact should an ignition event occur. In later sections, we similarly outline our plans to reduce the need for PSPS, as well as lessen the impact of PSPS on customers and communities. SCE continues to align with the Commission that PSPS is a measure of last resort, and SCE recognizes the impacts that these events have on the customers and communities that we are privileged to serve.

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[9] The approximately 300,000 structures include distribution, transmission, and combo poles.

[10] This consists of approximately 9,700 overhead distribution primary conductor miles and 4,400 overhead transmission conductor miles in High Fire Threat Districts (HFTD).

[11] SCE's HFRA is based on a combination of historical map boundaries (based on past fire management and response experiences), California Department of Forestry and Fire Protection's (CALFIRE) Fire Hazard Severity Zone maps, and the California Public Utility Commission's approved statewide HFTD maps. Collectively, SCE has considered Zone 1, Tier 2, and Tier 3 (collectively, the HFTD) and non-CPUC historical high fire risk areas to collectively be the HFRA. Zone 1 consists of Tier 1 High Hazard Zones (HHZ) on the map of Tree Mortality HHZs prepared jointly by the United States Forest Service and CALFIRE. Tier 1 HHZs are in direct proximity to communities, roads, and utility lines, and represent a direct threat to public safety. Tier 2 consists of areas on the CPUC's Fire Threat Map where there is an "elevated" risk for destructive utility-associated wildfires. Tier 3 consists of areas on the CPUC's Fire Threat Map where there is an "extreme" risk for destructive utility-associated wildfires.

[12] *See* 2022 WMP data tables: These estimates include customers and circuit miles within HFTD Tiers 1, 2, and 3 as well as adjacent non-HFTD locations. This definition of WUI is consistent with OEIS guidance.

2. Overview of Wildfire Risk and Proposed Plan

SCE defines a wildfire risk event as an "ignition associated with SCE's overhead electrical assets and operation in its HFRA." An analysis of SCE's CPUC-reportable fire events[13] and Electric Safety Incident Reports (ESIR)[14] data from 2017 to 2021 in SCE's HFRA demonstrates that the primary drivers of wildfire ignitions associated with utility equipment are as follows: (a) overhead wire contact with objects (*e.g.*, vegetation, metallic balloons, debris, etc.); (b) wire-to-wire faults; and (c) equipment and facility failure. SCE has classified fires simulated along each circuit segment within SCE HFRA into a series of outcomes.[15] We chose this method so that we can characterize wildfire risk at an extremely granular level. The analysis allowed SCE to tranche wildfire risk to every single circuit segment. The resulting outcomes are categorized based on the resulting consequences. These are denoted as Small, Destructive and Significant Fires, based on the following criteria:

- **Small Fires** are simulated fires that, at 8 hours after ignition, burned less than 300 acres with zero fatalities and no structures impacted;
- **Destructive Fires** are simulated fires that, at 8 hours after ignition, burned between 300 acres and 10,000 acres with zero fatalities and/or had fewer than 50 structures impacted;
- **Significant Fires** are simulated fires that, at 8 hours after ignition, burned more than 10,000 acres or had at least one fatality or had at least 50 structures impacted.

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[13] Per D.14-02-015, reportable fire events are any events where utility facilities are associated with the following conditions: (a) a self-propagating fire of material other than electrical and/or communication facilities; (b) the resulting fire traveled greater than one linear meter from the ignition point; and (c) the utility has knowledge that the fire occurred.

[14] Electric utilities must report electric incidents (accidents involving electric facilities), which meet any of the criteria as follows: (1) a fatality or injury involving electric facilities; (2) damage to property of the utility or others in excess of $50,000; (3) significant media coverage; (4) a major outage to at least 10% of the utilities entire service territory is experienced at a single point in time. In general, the electric utility must report these types of incidents to the Commission within two hours of their occurrence.

[15] The resulting wildfire risk scores are based on the maximum consequence over an eight-hour first burning period across a wide range of weather scenarios, representing known historical climatic conditions across SCE's HFRA.

SCE uses this granular data (approximately 200,000 circuit segments for distribution and 40,000 for transmission) to calculate risk spend efficiencies (RSEs) at each circuit segment. This level of granular information is presented in our workpapers for this chapter. For ease of reference and efficient presentation in the main text of this chapter, SCE has separated the results into three distinct and mutually-exclusive categories that broadly reflect our Integrated Grid Hardening Strategy.[16] These three categories are (1) "Severe Risk Areas," (2) "High Consequence Segments," and (3) "Other HFRA."

Severe Risk Areas are locations that are characterized by elevated population risk factors (*e.g.*, heightened egress risk, significant wildfire risk,[17] and/or heightened risk of high wind events). High Consequence Segments are segments where simulated fires exceed 300 acres in 8 hours and do not have the same level of population risk as the Severe Risk Areas. These circuit segments are sited in locations where wildfire can propagate over a relatively short period of time. Other HFRA encompasses locations within HFRA that do not meet either of the previous criteria but are identified by the Commission as areas of "extreme" and "elevated" wildfire risk in the current CPUC Fire Threat Map. These locations are still subject to regulatory and compliance requirements for enhanced mitigation activity, such as increased inspections and/or vegetation management.

Starting in late 2018, under SCE's Grid Safety & Resiliency Program (GSRP), SCE began installing covered conductor through its Wildfire Covered Conductor Program (WCCP). In the ensuing years, WCCP continues to be SCE's primary grid hardening tool (with very discrete deployment of TUG to date).

To further validate the effectiveness of covered conductor, in 2022 SCE, PG&E, and SDG&E jointly retained an independent third-party expert to perform lab testing of covered conductor effectiveness. That testing is still ongoing, but the results to date have initially validated that covering

[16] SCE's Integrated Grid Hardening Strategy is discussed below.

[17] Technosylva wildfire simulation score of greater than 10,000 acres in 8 hours for each segment.

conductor is very effective at mitigating the ignition risk drivers that the covered conductor effort is intended to address.

By 2025, SCE anticipates approximately 3,250 circuit miles will remain unhardened in SCE's HFRA. In this RAMP, SCE lays out a Proposed Plan to reduce the risk of ignitions to the extent feasible for these remaining miles over the 2025-2028 General Rate Case (GRC) funding period. Approximately 600 of these 3,250 unhardened miles are designated as Severe Risk Areas. In these particular locations, SCE will consider targeted undergrounding of primary overhead conductor as the preferred solution, appropriately modified to reflect the practical feasibility of implementing that solution in a given location. Accordingly, of these 600 miles, SCE currently anticipates that approximately 600 miles should be mitigated by undergrounding.[18]

For locations that meet the Severe Risk Area criteria, but undergrounding would not be practically feasible, SCE will deploy covered conductor supplemented with other vegetation and asset management activities. These activities include the Hazard Tree Management Program (HTMP), pole brushing, line clearance, and enhanced inspection practices where appropriate. Collectively, deploying covered conductor in combination with these other activities is known as CC++.

Of the remaining 2,650 unhardened miles, approximately 1,200 of the miles are not included in Severe Risk Areas but are categorized as High Consequence Segments. For these 1,200 miles, SCE proposes to deploy the full suite of CC++ measures as the preferred mitigation option. Although these miles do not have the risk profiles that would qualify them as Severe Risk Areas (and that would therefore lead SCE to underground them where feasible), they are still sufficiently risky so that covered conductor standing alone would be insufficient from a risk mitigation standpoint.
The CC++ solution offers additional protection and risk mitigation beyond what covered conductor alone can provide.

[18] There are situations that can make undergrounding unreasonably challenging. Examples include when the overhead conductor is sited directly above rocky mountains or other substantially challenging terrain, or when the overhead conductor is sited at a location where there is not enough room to meet required clearances for undergrounding.

Then, for the remaining 1,450 or so of remaining unhardened miles that are categorized as Other HFRA,[19] SCE proposes to, on an as-needed basis, reactively replace (rather than proactively replace) damaged bare wires with covered conductor pursuant to SCE's current construction standards in HFRA. SCE will also continue to perform additional wildfire mitigation activities on these unhardened miles, including but not limited to annual asset inspections, fast curve settings, and vegetation management.

3. RSE for PSPS As a Mitigation

As noted in Chapter 2 Section IV.E, in this RAMP SCE has generally calculated RSEs for both controls and mitigations. An exception is for PSPS as a mitigation to ignition risk. Here, SCE has not calculated an RSE for PSPS, for two principal reasons.

First, the Commission has made clear that it is not appropriate to justify the use of PSPS based on its RSE. Specifically, in the Final Decision in Track 1 of SCE's Test Year 2021 GRC, the Commission held the following: "Regarding the use of RSEs, the S-MAP settlement (D.18-12-014) provides that utilities are to provide a ranking of proposed mitigations by RSE as part of their GRC submission. As a general matter, RSEs provide a useful point of comparison regarding the cost-effectiveness of proposed mitigations belonging to the same risk tranche and, **with the exception of Public Safety Power Shutoff (PSPS)** the default should always be for a utility to provide RSE calculations for its proposed mitigations."[20] The Commission further observed that "[a]s noted in Resolution WSD-002, RSE is not an appropriate tool for justifying the use of PSPS."[21]

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[19] That is, segments in HFRA that are neither High Consequence Segments nor in Severe Risk Areas. Some of these Other HFRA miles may in due course be hardened pursuant to the "buffer" approach that the Commission endorsed in its decision on SCE's Test Year 2021 GRC. During the course of installing covered conductor through WCCP, operational considerations as well as the categorization are relevant when determining the actual amount of final deployed scope. In SCE's 2021 GRC, the Commission recognized this by authorizing a 20% "buffer" of additional miles when approving a preliminary scope of work. *See* D.21-08-036, p. 200, fn. 669. That buffer will continue to be necessary under SCE's Integrated Grid Hardening Strategy when addressing spans adjacent to those circuit segments that SCE has determined to be high consequence and/or severe risk.

[20] D.21-08-036, p. 38 (emphasis added).

[21] *Id*. at p. 38, fn. 95.

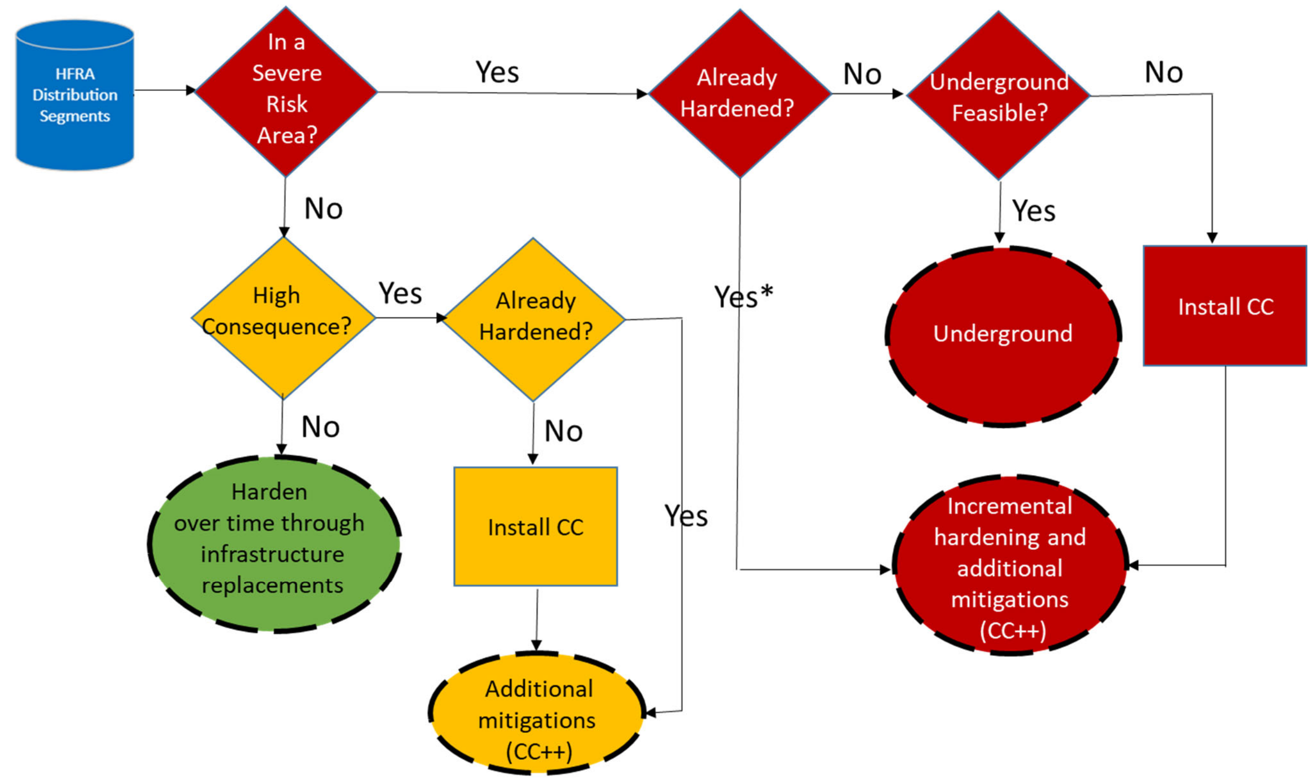
Second, and consistent with this Commission guidance, SCE does not use the RSE for PSPS to determine when or where PSPS is used. While SCE has not submitted a calculation of PSPS's RSE, we would expect it to be quite high relative to other ignition mitigation measures. But SCE uses PSPS only as a necessary measure of last resort to avoid ignitions that could lead to catastrophic wildfires. In other words, the scope, frequency, and duration of PSPS events SCE must call are unrelated to the RSE for PSPS.

In light of these two reasons, particularly the Commission's recent guidance set forth in the Track 1 Final Decision in SCE's 2021 GRC, SCE has not provided an RSE for PSPS as a mitigation measure against ignition risk in this RAMP.

4. Proposed Plan and Alternative Plans To Address Wildfire Risk

The following diagram depicts SCE's decision-making matrix for our Proposed Plan (Figure I-3). The number of circuit miles in each category can be found in Table I-1.

Figure I-3
Integrated Grid Hardening Strategy



* Because of the uncertainties associated with accelerating climate change and changing risk profiles, in certain cases, SCE may need to underground specific circuit segments that were already hardened with covered conductor to further reduce risk and protect SCE's customers. At this time, SCE expects such occurrences to be the exception and not the rule.

Table I-1
2025-2028 Scope of WCCP and TUG for Proposed Plan

	Estimated Unhardened Overhead Circuit Miles by end of 2024	**2025 - 2028 Scope (Circuit Miles)**	
		Wildfire Covered Conductor Program	**Targeted Undergrounding**
Severe Risk Areas	580	0	580
High Consequence Segments plus Buffer	1,400	1,250	0
Total	**1,980**	**1,250**	**580**

In addition to our Proposed Plan, SCE also describes two Alternative Plans, pursuant to RAMP requirements. We believe the Proposed Plan considers the most effective combination of tools in our "toolbox," including a mix of covered conductor, TUG, and Rapid Earth Fault Current Limiter

(REFCL).[22] It strikes a reasonable balance between risk reduction, cost to customers, execution feasibility, and technology advancements. It carefully addresses heightened wildfire risk and public safety concerns for both Severe Risk Areas and High Consequence Segments.

Alternative Plan #1 differs from our Proposed Plan in that it does not employ TUG as a mitigation option in the 2025-2028 period. In Alternative Plan #1 SCE would, instead, implement the full CC++ suite as the primary mitigation for both Severe Risk Areas and High Consequence Segments. Alternative Plan #1 would not fully address such factors as population egress, significant consequence segments, or high wind locations that could still be subject to PSPS despite being having covered conductor fully deployed.

Alternative Plan #2 represents a higher tolerance for simulated wildfire risk, by raising the High Consequence Segments threshold from 300 acres to 1,000 acres in 8 hours. Alternative Plan #2 would leave many locations exposed, particularly those in the WUI.[23] Any ignition in these WUI locations has the potential to lead to large and destructive fires adjacent to urban locations, especially with the continued increase in dry fuel build-up and hotter temperatures with worsening climate change impacts.

Stated another way, the Proposed Plan for wildfire risk would provide reasonable assurances that by the end of the RAMP period, no overhead bare conductor remains in current HFRA in locations where, if an ignition were to occur, there is a high likelihood of significant fires based on current risk modeling. (Note: the current modeling has a time-based modeling limitation for wildfire spread).[24]

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22 REFCL is discussed in detail below.

23 WUI is dense housing adjacent to vegetation that can burn in a wildfire. https://frap.fire.ca.gov/media/10300/wui_19_ada.pdf.

24 As wildfire simulations increase in time duration, so does the uncertainty associated with those simulations. It is not uncommon for both natural (*e.g.*, changing wind direction) and human activity (*e.g.*, fire suppression) to change the intensity and direction of wildfires as they progress. Additionally, as seen during the 2020 wildfire season, the availability of suppression resources over a large geographic area can influence how much attention individual fires receive, as well as how they are contained and suppressed. Stated simply, while it is theoretically possible to model wildfire spread beyond 8 hours, the longer-duration those simulations become the less certainty there can be about their accuracy.

For Alternative Plan #1, there would still be some remaining ignition risk for the RAMP period in approximately 580 overhead conductor miles in current HFRA in locations where, if an ignition were to occur, there is a high likelihood of significant fires based on current risk modeling. There would be some remaining ignition risk because these miles would not be undergrounded (although covered conductor provides substantial ignition-risk benefits).

For Alternative Plan #2, approximately 1,250 overhead conductor miles located in current HFRA would remain unhardened for the RAMP period, and therefore would be subject to substantial ignition risk (although SCE would still continue to perform enhanced inspections and vegetation management work on these areas) for the 2025-2028 period.

5. Overview of PSPS Risk, Proposed Plan, and Alternatives

As mentioned above, SCE uses PSPS as a measure of last resort to mitigate the risk of extreme wildfire events. When extreme weather events threaten SCE's overhead electrical infrastructure, whether due to debris blowing or potential equipment failure, SCE must proactively de-energize limited sections of its system. In the face of such conditions, SCE's foremost mission is the safety of the public, our customers, and our employees.

However, we recognize the serious impact of PSPS on our customers and communities even during extreme weather. To that end, SCE's PSPS decision-making process is guided by four fundamental objectives: (1) to protect public safety; (2) to keep the power on for as many customers as reasonably possible; (3) to communicate clearly and accurately about de-energization and re-energization; and (4) to minimize the impacts of de-energizations through customer support programs.

Prior to proactively de-energizing circuits, SCE performs other activities, which include enacting operating restrictions,[25] implementing fast curve (FC) settings,[26] and performing switching operations (where possible) on circuits in scope for potential de-energization (in advance of a period of concern regarding the effects of the extreme weather on the applicable fire danger). SCE also conducts pre-patrols of circuits in scope and deploys field personnel to monitor real-time weather and Fire Potential Index (FPI) data.

SCE's PSPS decision-making process is based on quantitative and qualitative factors which account for the impacts of these activities to emergency services. SCE uses circuit-specific thresholds for fuel and wind conditions, as well as input provided by field resources. These factors, known as FPI, include but are not limited to wind speeds, humidity, and fuel moisture levels.[27] The thresholds are continuously reviewed to reflect the risk of significant wildfire events against the potential for harm to customers resulting from the loss of power. Circuit-specific FPI activation thresholds are calculated using the following inputs:

- Wind speed - Sustained wind velocity at six meters above ground level.
- Dew point depression - The dryness of the air as represented by the difference between air temperature and dew point temperature at two meters above ground level.
- Energy release component (ERC) – This input has been defined by the U.S. Department of Agriculture as follows: "The available energy (BTU) per unit area

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[25] SCE's System Operating Bulletin No. 322 includes restrictions to limit the potential for a spark to occur or to mitigate the risk of an ignition; this includes limits to circuit switching, recloser operations, and requirements for personnel to be physically present when operating equipment and circuits subject to hot work restrictions.

[26] FC settings reduce fault energy by increasing the speed with which a protective relay reacts to most fault currents. FC settings can reduce heating, arcing, and sparking for many faults compared to conventional protection equipment settings. Further details are found in SCE's 2022 Wildfire Mitigation Plan Update (Revised), WMP Activity SH-6.

[27] SCE's detailed technical paper, Quantitative and Qualitative Factors for PSPS Decision-Making, can be found at https://energized.edison.com/psps-decision-making.

(square foot) within the flaming front at the head of a fire reflects the contribution of all live and dead fuels to potential fire intensity."

- 10-hour dead fuel moisture - A measure of the amount of moisture in ¼-inch diameter dead fuels, such as small twigs and sticks.
- 100-hour dead fuel moisture - A measure of the amount of moisture in 1- to 3-inch diameter dead fuels, *i.e.*, dead, woody material such as small branches.
- Live fuel moisture - A measure of the amount of moisture in living vegetation.
- Normalized Difference Vegetation Index (NDVI) - a measure of plant health which is based on the greenness of vegetation.

In addition to the broad use of FPI, SCE also calculates separate de-energization wind-speed thresholds for every circuit. PSPS event activation thresholds are set based on a number of circuit-specific conditions. There are a handful of circuits, for instance, in which the wind threshold for de-energization is below the National Weather Service (NWS) advisory level. This is because those circuits have a history of circuit outages at lower wind speeds. Wind de-energization thresholds also account for circuit health, including any issues identified through patrols or high simulated wildfire consequence scores.

Finally, SCE's circuit-specific wind-speed thresholds also include consideration of the simulated wildfire consequence score on those circuits. This simulated score estimates the potential impact of a simulated wildfire ignition on communities located in or adjacent to those circuits (*i.e.*, the higher the score, the greater the potential consequences in terms of acres burned, structures damaged and/or destroyed, and/or population impacted). De-energization wind-speed thresholds[28] are determined for each circuit to prioritize circuits for de-energization ahead of any potential PSPS event. This is particularly important for large events, where many circuits may need to be evaluated simultaneously.

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28 De-energization thresholds can be reduced based on risk factors such as FPI and circuit health conditions.

This RAMP examines PSPS not only as an ignition mitigation for significant wildfire events, but also as a standalone risk. SCE proposes a balanced Proposed Plan to mitigate the potential impact of PSPS through a combination of robust infrastructure deployment, as well as operational mitigation activities. The infrastructure programs we propose in this plan describe an integrated grid hardening strategy designed to provide co-benefits -- reduce wildfire risks, while also reducing the need for PSPS. In addition to the proposed grid hardening, SCE also proposes to continue operational mitigation activities. These are primarily customer care programs, designed to mitigate the potential impacts of proactive de-energization events on customers. There is a particular focus in these programs on those customers that are considered Medical Baseline (MBL) and Access and Functional Needs (AFN).

B. Summary of Results

Table I-2 summarizes the likelihood of risk event (LoRE) and consequences (CoRE) for pre- and post-mitigations over the 2025-2028 period.[29]

Table I-2
Summary of Pre- and Post- LoRE and CoRE Risk Scores

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Wildfire - All HFRA	32.5	1.5	47.6	27.3	1.4	39.6
T1 - Severe Risk Areas	4.3	3.6	15.4	2.7	4.5	12.2
T2 - High Consequence Segments	13.5	2.2	29.3	10.9	2.3	24.7
T3 - Other HFRA	14.8	0.2	2.9	13.8	0.2	2.7
PSPS	24.0	0.0068	0.16	24.0	0.0068	0.16

29 LoRE – likelihood of risk event. CoRE – consequence of risk event. Risk Score is the product of the LoRE and CoRE. For additional information on the risk modeling methodology, please refer to Chapter 2 – Risk Model and Methodology.

II.

RISK ASSESSMENT

A. Risk Definitions and Scope

In this chapter, SCE evaluates the risk of wildfire ignition associated with SCE equipment, using the risk bowtie method. SCE also assesses the potential risks associated with PSPS, and has developed a PSPS risk bowtie as well. The risk bowtie for wildfire maps the progression of the wildfire ignition risk from ignition drivers through the risk event. The bowtie then examines discrete outcomes, and associated ignition consequences for each circuit segment.[30]

The risk bowtie for PSPS risk depicts the risk of a circuit exceeding its established FPI and wind thresholds, along with the associated outcomes and potential safety, reliability, and financial consequences. This risk is described in terms of whether a de-energization would have likely occurred, and how much notice was received beforehand.

1. Wildfire

The wildfire triggering event is defined as an ignition associated with SCE's overhead electrical assets and operation in its HFRA. Table II-3 below summarizes the scope of the risk in this chapter. In the 2018 RAMP, SCE focused on risks associated with SCE's distribution equipment. At that time, approximately 90 percent of all of the fires associated with electrical equipment in SCE's service area were related to distribution level voltages (33kV and below). Though this percentage has not drastically changed,[31] our 2022 RAMP addresses this risk more broadly. SCE characterizes the risk as inclusive of ignitions associated with utility equipment at both the distribution and transmission voltage levels within SCE's HFRA. In addition to including transmission voltages, other SCE improvements include a new definition for outcomes and tranches (*e.g.*, outcomes based on a different simulated wildfire size). We also utilize a new and enhanced risk model (see Figure II-5 below).

[30] The consequences are simulated for each segment.

[31] Based on SCE's 2022 WMP, 93 percent of all of the fires associated with electrical equipment in SCE's service area are related to distribution-level voltages.

Table II-3
Scope of Widlfire Risk Bowtie

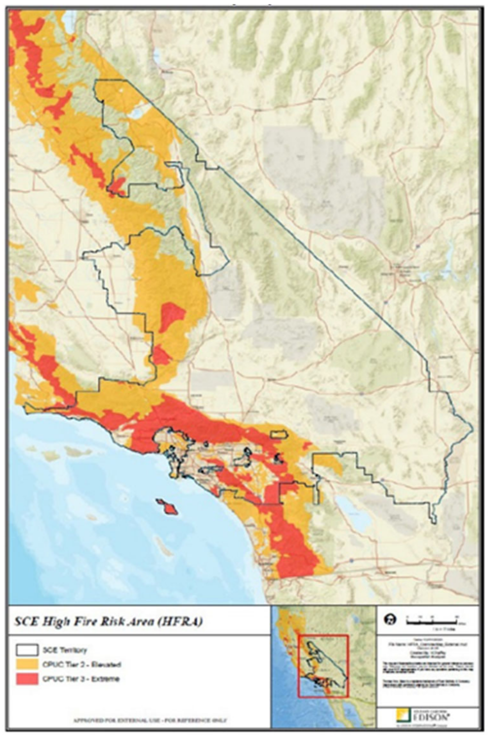
In Scope	• Ignition in SCE's HFRA relating to Distribution and Transmission systems.
Out of Scope	• Ignition in SCE's non-HFRA and non-BL322/SOB322 areas* • Ignition related to Generation/Substation assets • Ignitions not associated with SCE's equipment
*SCE historically treated HFTD as well as certain non-HFTD areas collectively as HFRA (sometimes referred to as "BL 322 areas"). On December 17, 2020, the Commission approved in part SCE's August 19, 2019 Petition for Modification to conform the Commission's official HFTD fire map with SCE's internal HFRA (D.20-12-030). D.20-12-030 approved the inclusion of 37 out of 43 of SCE's proposed HFRA "polygons" in the official HFTD fire map. In accordance with D.20-12-030, SCE has now fully conformed its HFRA to the HFTD fire map, as revised therein.	

In D.17-12-024, the Commission adopted regulations to enhance wildfire safety in the statewide High Fire Threat Districts (HFTD).[32] These fire-safety regulations aim to reduce the fire hazards associated with overhead power-line facilities in elevated and extreme areas throughout the State. The regulations are contained in the Commission's General Orders (GO) 95, 165 and 166; and in Rule 11 of each of the electric Investor-Owned Utilities' (IOU) electric tariff rules. The HFTD tiers were determined based on elevated hazards for the ignition and rapid spread of power-line fires due to strong winds, abundant dry vegetation, and other environmental conditions.

In addition to CPUC-designated HFTD, SCE has petitioned for additional areas, known as Bulletin 322 (BL322), to be treated as high fire risk areas. Collectively, SCE refers to HFTD and BL322 areas as High Fire Risk Areas (HFRA). Since adoption of the HFTD maps in 2018, SCE has complied with new construction standards, enhanced vegetation clearances, increased asset inspections, and shortened remediation timelines, consistent with applicable Commission General Orders (GO) designed to reduce fire risk.

[32] The Commission designates these districts, as shown in the Fire Threat map issued by the State.

Figure II-4
Current Boundary Map of SCE's HFRA



Risk modeling and analysis has served as a cornerstone in developing and executing our Wildfire Mitigation Plans (WMPs). Our modeling and analysis has continued to mature over time, and we expect further refinements in the future as this area continues to evolve.

In 2018, we used a multi-step process to develop our RAMP Report, which contained nine top safety risks, including wildfire.[33] SCE developed a RAMP risk model and a Multi-Attribute Value Function (MAVF) to quantify our enterprise-level safety risks and evaluate mitigation options. The risk score generated from SCE's MAVF scoring framework is called the Multi-Attribute Risk Score (MARS). The analysis and framework informed SCE's 2019 WMP. In parallel with preparing SCE's Test Year 2021 General Rate Case application, we developed the Wildfire Risk Model (WRM), which was used to determine the probability and consequences of ignitions at the asset level.

33 SCE's 2018 RAMP Report, Chapter 10.

In 2019, SCE continued to use the RAMP model and MARS framework to assess system- or HFRA-level wildfire risks and risk mitigation. We used HFRA-level "top down" averages for the probability and consequence of ignitions. Once the appropriate mitigation was selected for overall implementation (*e.g.*, covered conductor), SCE used the segment level probability of ignition (POI) and Reax-based[34] consequence model (together referred to as the WRM) to risk-rank conductor segments. This "top down" RAMP model, along with the "bottoms-up" circuit segment prioritization, was used to determine the prioritization of covered conductor installations in the field, in conjunction with other operational and resource considerations. The results of these analyses were included in SCE's Test Year 2021 GRC and 2020 WMP.

In 2020, SCE achieved several key milestones in enhancing our wildfire risk analytics. We developed asset-specific POI models for transmission and sub-transmission assets to add to our previously-built distribution asset models. SCE also transitioned to a new fire consequence modeling tool developed by Technosylva.[35] We developed a method to translate the risk scores produced by our POI and consequence models into unitless values, consistent with the RAMP approach and using the MARS framework at the structure (pole or tower) level.

Finally, SCE developed a PSPS risk calculation to more comprehensively account for risk reduction benefits, as well as risks associated with the use of PSPS. The new PSPS risk calculator provided granularity at the individual circuit segment level.

We integrated all of these improvements and additions into the overarching model referred to as the Wildfire Risk Reduction Model (WRRM). In 2021, SCE updated its existing asset-specific WRRM POI models by using the latest asset data, weather data, and most suitable algorithms. At the same time, SCE updated the Technosylva fire consequence models by including additional historical weather scenarios and up-to-date fuel data including recent burn scars. This would better capture the potential fire consequences. SCE also developed a Severe Risk Methodology to assess the

[34] Reax Engineering is an experienced fire science consulting firm.

[35] Technosylva provides simulation data on wildfire spread.

risks associated with factors not captured through our wildfire ignition simulations, such as egress risk. SCE summarizes the evolution of its risk modeling in Figure II-5 below.

Figure II-5
Evolution of SCE's Wildfire (and PSPS) Risk Modeling

2. <u>PSPS</u>

The PSPS triggering event is defined as a PSPS activation driven by weather forecasts exceeding FPI and wind speed thresholds. Table II-4 below summarizes the scope of the risk for purposes of this RAMP chapter. To develop the consequences for each outcome, SCE approximated the total population hours of interruption by multiplying recorded customer minutes of interruption[36] by three to convert service accounts to customer counts. Because SCE has not recorded any serious injuries or fatalities linked to a PSPS event, we utilized the 2003 Northeast Blackout, 2011 Southwest Blackout, and 2019 PSPS Post-Event reports to create a multiplier to population hours of interruption, to estimate safety outcomes of each event.

[36] Also known as CMI. This is the total duration of an outage at a meter level.

Table II-4
Scope of PSPS Risk Bowtie

In Scope	• Customers in HFRA on circuits that are forecast to exceed PSPS thresholds.
Out of Scope	• Customers in HFRA whose circuits are not at risk for PSPS de-energization.

B. <u>Risk Bowties</u>

1. <u>Wildfire</u>

To evaluate wildfire risk in this RAMP, SCE constructed a risk bowtie, as shown in the figure below. The risk exposure was SCE's approximate 9,700 miles of overhead primary conductor and 4,400 miles of overhead transmission conductor in SCE's HFRA. The triggering event at the center of the wildfire bowtie was an ignition in SCE's HFRA associated with SCE's electrical assets and operation in SCE's HFRA. On the left-hand side of the bowtie, historical ignition and fault analysis determined that potential ignitions were primarily driven by contact from objects (such as vegetation or mylar balloons), equipment/facility failure, and wire-to-wire contact (during periods of high winds).

The potential outcomes and consequences of these ignition events were estimated on the right-hand side of the bowtie, using the Technosylva consequence model. The model was updated to include 444 worst weather days as well as improved vegetation maps to better represent the diversity of fire regimes throughout SCE's service territory. The model estimated the potential spread of a fire over a given time, as well as the corresponding impact of a fire in natural units - structures, acres, and population. Using a set of reasonable assumptions, SCE calculated the safety, reliability, and financial impacts.[37]

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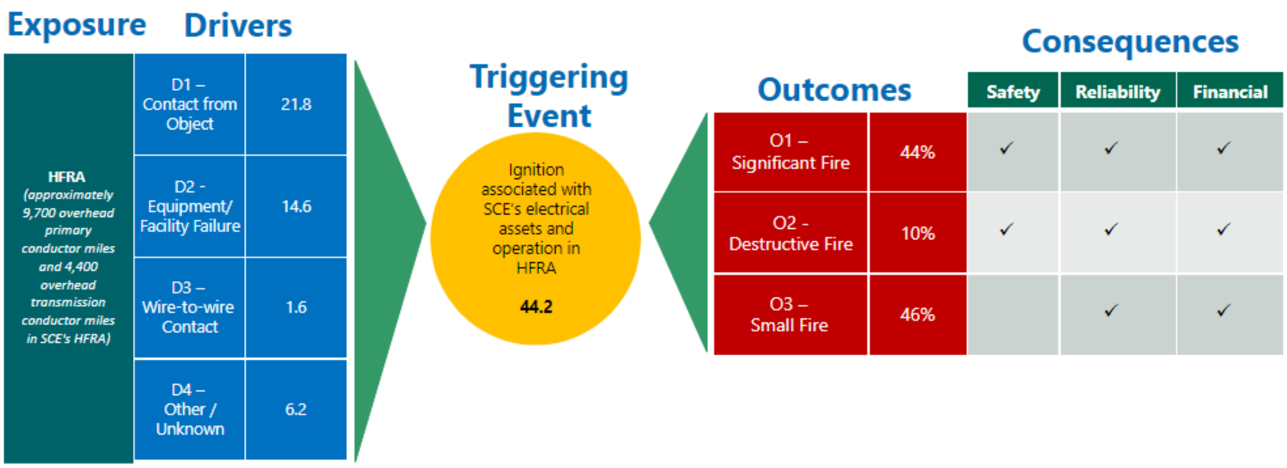
[37] *See* WP Ch. 4 - RAMP WF / PSPS MARS Workpaper.

Figure II-6
Risk Bowtie for Wildfire Risk – HFRA (Distribution and Transmission)



2. PSPS

As discussed above, this RAMP considers PSPS not only as a mitigation to wildfire ignition risk, but also as a risk in and of itself. This approach is based on Commission[38] and OEIS guidance, as well as stakeholder feedback. As we did not include PSPS as a risk in our 2018 RAMP, this is SCE's first risk bowtie for PSPS. SCE's PSPS risk bowtie includes risk exposure, risk drivers, triggering events, outcomes, and consequences to demonstrate the relationship between these factors. Because SCE only activates PSPS protocols on circuits in HFRA, it is only those circuits and the associated downstream circuits they serve that are potentially exposed to proactive de-energization. As touched on earlier in this chapter, SCE proactively de-energizes PSPS circuits only if fuel and wind conditions meet or exceed[39] circuit-specific criteria (see Figure II-7 below).

SCE has experienced 26 PSPS events in 2020 and 2021 combined. Twenty of those events resulted in at least one circuit de-energization. For each PSPS event, SCE assesses and compares potential public safety risks associated with proactive de-energization (PSPS risk) for all

[38] *See* D.21-11-009, Ordering Paragraph 1.h, p. 142 (stating that each IOU shall model PSPS events as risk events pursuant to the requirements in D.18-12-014).

[39] SCE does occasionally de-energize circuits prior to the criteria being reached. This can occur in large, complex events when internal subject matter experts have a high confidence that circuits will soon exceed those criteria and additional time may be needed to carry out the de-energization process.

circuits in scope; SCE uses its PSPS In-Event Risk Comparison Tool.[40] Inputs into this Tool include, among other items, in-event weather, wildfire simulation models, and circuit-specific data. The results of the analysis are displayed on SCE's in-event management tools and are used by Incident Commanders to inform de-energization decisions, in conjunction with other relevant quantitative and qualitative factors.

All of this information is used to calculate potential Safety, Financial, and Reliability impacts (or attributes) of: (1) a wildfire and (2) a proactive de-energization event, as summarized in Table II-5 below. SCE quantifies the resulting PSPS risks and Wildfire risks using natural unit consequences for each risk type or attribute — structures impacted, acres burned, CMI, serious injuries and fatalities, etc. "Safety" risk is expressed as an index, "Reliability" risk is measured in terms of CMI, and "Financial" risk is measured in dollar amounts.

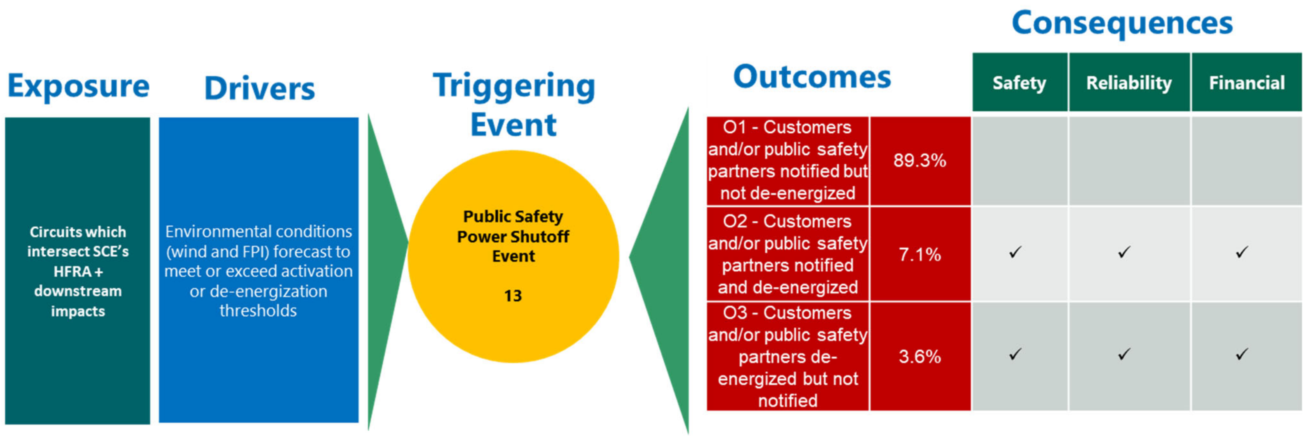
[40] SCE will continue to refine the In-Event PSPS Risk Comparison Tool based on real-time experience, additional data, and ongoing benchmarking with other IOUs. The estimates and assumptions described herein are based on risk models reflecting current industry best practices, and are subject to change or update as the modeling improves.

Table II-5
PSPS Risk and Consequence Details

Risk Attribute	PSPS Consequences
Safety	SCE leverages epidemiological studies and information drawn from past widespread power outage events including the 2003 Northeast Blackout, the 2011 Southwest Blackout, and the IOUs' 2019 PSPS post-event reports.* The resulting estimates of fatalities and serious injuries per CMI are intended to approximate potential safety consequences due to the power outage, such as illnesses resulting from food spoilage or exacerbation of existing underlying health conditions. SCE enhanced the PSPS safety attribute by applying a circuit-specific AFN/NRCI multiplier. This multiplier represents the relative ranking of each circuit based on the number of AFN and NRCI customers on the circuit.
Reliability	SCE estimates the total CMI due to proactive de-energization on a circuit. It is the product of the number of customers on a circuit and the total number of minutes of estimated interruption per customer. SCE assumes 1,440 CMI per customer (24 hours x 60 minutes) to represent de-energization over a 24- hour period.
Financial	SCE conservatively assumes $250** per customer, per de-energization event to quantify potential financial losses for purposes of comparing PSPS risk to wildfire risk. The figure represents potential customer losses, such as lost revenue/income, food spoilage, cost of alternative accommodations, and equipment/property damage. This value is based on a VoLL, which is a widely accepted industry methodology to estimate a customer's willingness to accept compensation for service interruption. VoLL is dependent on many factors, including the type of customer, the duration of the outage, the time of year, and the number of interruptions a customer has experienced. SCE's VoLL estimate is consistent with academic and internal studies concerning estimation of VoLL for a single-family residential customer for a 24-hour period.

* See, e.g., Anderson, G.B., Bell, M.B (2012). Lights Out: Impact of the August 2003 Power Outage on Mortality in New York, NY, Epidemiology 23(2) 189-193. doi: 10.1097/EDE.0b013e318245c61c.
** In utilizing the $250 per customer, per de-energization event to approximate potential financial losses on average, SCE recognizes that some customers may experience no financial impact, while other customers' losses may exceed $250. The $250 value is a conservative assumption used for the limited purpose of estimating the potential financial consequences of PSPS as one of many inputs into SCE's PSPS In-Event Risk Comparison Tool. It is not an acknowledgment that any given customer has or will incur losses in this amount, and SCE respectfully reserves the right to argue otherwise in litigation and other claim resolution contexts, as well as in regulatory proceedings.

Figure II-7
Risk Bowtie for PSPS Risk[41]



C. Drivers

1. Wildfire

The Wildfire risk drivers included in the 2022 RAMP are largely the same as those in the 2018 RAMP. One key difference is that there are additional sub-drivers for Equipment/Facility Failure (EFF) in the current filing compared to the previous filing. To identify the drivers that caused the Wildfire triggering event in SCE's HFRA, SCE analyzed CPUC-reportable fires that were associated with SCE's distribution and transmission systems in SCE's HFRA between 2017 and 2021. SCE added additional fires from its Electric Safety Incident Reports (ESIRs) to increase the sample size of the driver analysis.

Our analysis demonstrated that, on average, there are approximately 44 ignitions associated with SCE's equipment in its HFRA per year. The primary drivers are: Contact From Object (CFO) (50%) and Equipment/Facility Failure (EFF) (33%). The remaining 17% are attributable to wire-to-wire contact, as well as other causes, such as contamination, vandalism, or unknown.

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41 While SCE has not modeled any consequences for O1 in this RAMP, SCE acknowledges that the Commission has recognized the potential financial impacts for certain critical facilities and public safety partners resulting from such "false positive" PSPS notifications. *See* D.21-06-034 at pp. 79-80. SCE notes that the Commission in that Decision declined to "address this issue at this time." *Id.*

a) D1 – Contact From Object (CFO)

CFO includes external factors that can cause SCE's equipment to fail, and result in SCE's equipment being associated with an ignition. Figure II-6 above shows that based on a five-year average, CFO accounts for approximately 22 out of 44 (*i.e.*, 50%) of ignitions. Table II-6 below provides a further listing of CFO sub-drivers.

Table II-6
D1 (CFO) Sub-driver Statistics (Distribution and Transmission)

Contact From Object (CFO) Sub Driver	Total (2017 - 2021)	Annualized Frequency	% of CFO Driver Frequency
D1a - Vegetation	26	5.2	24%
D1b - Animal	27	5.4	25%
D1c - Balloons	30	6	28%
D1d - Vehicle	17	3.4	16%
D1d - Other / Unknown	9	1.8	8%
Total	**109**	**21.8**	**100%**

(1) D1a – CFO – Vegetation

Even with SCE's existing vegetation management programs, vegetation can still make contact with overhead conductor and cause an ignition and/or a wire-down event. This can occur in several different ways. To take just one example, branches or palm fronds can break or come loose from the tree and fall into a line.[42] This failure mode is known as a "Fall In." In other circumstances, branches or palm fronds can be blown in ("Blow Ins") by wind into overhead conductor. Besides causing faults on the lines themselves, these branches and palm fronds themselves can ignite and subsequently trigger a fire. The branches or palm fronds can come from trees located 200 feet away or more from overhead lines. This distance is well beyond regulatory-required and/or recommended line clearances.

Finally, vegetation can grow into a line ("Grow In"). Vegetation growth rates can vary. Trees or other vegetation may grow faster than anticipated between scheduled

[42] In addition to branches or palm fronds separating from the tree and falling into a line, the entire tree itself can fall down and under certain circumstances strike the line.

inspections. Accordingly, vegetation can grow into lines and make contact, despite SCE's compliant efforts to inspect and maintain clearances throughout its 50,000 square-mile area.

(2) D1b – CFO – Animal

Many animals come in contact with SCE's facilities on a daily basis. When an animal or bird is sitting or walking on an overhead conductor, its feet are at the same voltage potential[43] and the animal or bird will not be electrocuted. However, electrocution can occur when one of the animal's feet or wings comes into contact with an object at a different voltage potential (such as another conductor, or a grounded object like a tree branch) while the other foot (or feet) remains on the conductor. Electrocution results in severe injury or death to the animal and damage to the conductor and other electrical equipment impacted by the resulting fault. Additionally, the remains of the animal itself can ignite, and cause a fire.

(3) D1c – CFO – Balloons

Foil-lined or metallic balloons can potentially damage overhead electrical equipment because of their conductivity. Current California law[44] has recognized this concern, and mandates that all helium-filled foil balloons be weighted. This helps prevent the balloons from escaping and making contact with overhead electrical facilities. When a metallic balloon contacts overhead lines, it can create a short circuit. This can cause a large power arc, resulting in circuit damage, overheating, fire, or an explosion.

(4) D1d – CFO – Vehicle

Vehicles can come into contact with SCE's poles and other aboveground equipment, resulting in damage to the pole and/or equipment.[45] Vehicle impact causes SCE's equipment to fail in many ways: conductor or other equipment falling to the ground; conductor

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43 Voltage potential is a measure of the propensity for electricity to travel from one point to another.

44 Balloon Law, California Penal Code, §653.1 (Amended by Stats. 2018, Ch. 262, Sec. 2. (AB 2450), effective January 1, 2019.)

45 Although not covered in this risk analysis, SCE is sensitive to the fact that there can also be injury to the driver and/or passengers, as well as damage to the vehicle.

slapping together causing a fault; or the pole falling to the ground and taking the conductor with it. Sometimes, the failure can result in an ignition.

(5) D2c – CFO – Other

Contact from other unspecified objects, or foreign material, includes items such as tennis shoes, chains, gunshots, ice, crop dusting and other items. Each object has the potential to cause different types of failures, ranging from a fault to equipment failure, or ignition of the object itself.

b) D2 – Equipment/Facility Failure (EFF)

EFF includes events caused by failure of SCE's equipment, independent of events listed in D1. Figure II-6 above shows that EFF is the second-largest driver in the number of ignitions, on average. Table II-7 below further displays the sub-drivers of EFF.

Table II-7
D2 (EFF) Sub-driver Statistics (Distribution and Transmission)

Equipment/Facility Failure Sub Driver	Total (2017 - 2021)	Annualized Frequency	% of EFF Driver Frequency
D2a - Capacitor Bank	-	-	-
D2b - Conductor	30	6	41%
D2c - Crossarm	1	0.2	1%
D2d - Fuse	1	0.2	1%
D2e - Insulator	5	1	7%
D2f - Other	14	2.8	19%
D2g - Pole	2	0.4	3%
D2h - Splice/Clamp/Connector	11	2.2	15%
D2i - Switch	1	0.2	1%
D2j - Transformer	8	1.6	11%
Total	**73**	**14.6**	**100%**

(1) D2a – EFF – Capacitor Bank

SCE uses capacitor banks to compensate for reactive power losses and to regulate voltages on the distribution system. Approximately 85% of all distribution capacitor banks on SCE's system are installed on overhead circuits. Failing capacitor banks may create arcing from the associated equipment. The released electrical energy can be sufficient to cause an ignition, either at ground level or at pole-top level.

(2) <u>D2b – EFF – Conductor</u>

When an energized conductor fails and hits the ground, an ignition can occur. In general, there are two ways overhead conductor can experience failure. The first is when the system's short circuit duty (SCD) exceeds a conductor's rating over a defined time period (which is expressed as a curve based on conductor temperature). Generally, SCD indicates the relative strength of an electrical system, typically measured by the current (in amps) that the system can supply when fault conditions occur. If, at any given point in the system, fault current exceeds the conductor's ability to withstand it, then fault conditions can damage the conductor and lead to conductor failure. Older small conductor is especially vulnerable to damage during fault conditions, because it typically possesses a lower conductor rating, or current carrying capacity, compared to larger conductor.

The second way is conductor fatigue. Conductor fatigue refers to the decrease in overhead conductor's ability to withstand forces experienced during operational conditions. For overhead wire, the likelihood of fatigue-related failures tends to increase over time, as the conductor is exposed to longer periods of operational stress. For example, overhead conductors have both a normal long-term thermal rating and a higher short-term emergency thermal rating. Emergency thermal ratings are used to accommodate higher levels of load. These ratings are typically relied on during abnormal operating conditions, such as when transferring customers between adjacent circuits in order to restore service as rapidly as possible during circuit outage conditions.

Beyond the operating conditions described above, the conductors could also be exposed to very high-magnitude short circuit current from time to time, when there is a fault condition further downstream in the circuit. Even though these short circuit currents are typically very brief in duration (usually less than 1 second), the extremely high current level can result in a rapid increase in localized temperature of the conductor. This can start to change the molecular structure of the conductor material; the result is a significant and permanent reduction in the mechanical strength of the conductor. When coupled with other induced mechanical loading such as wind, vibration, and other environmental factors, this will contribute to the conductor experiencing fatigue-related failures at some point in its lifetime.

(3) D2c – EFF – Crossarm

Crossarms are mounted on distribution poles and used to support overhead conductor or other pieces of overhead distribution equipment. As crossarm pieces weaken or deteriorate over time, either the crossarm can break or the bracket that attaches the crossarm to the pole can fail. In either case, conductor can come into contact with: (a) other conductors, (b) the pole, (c) other pieces of electrical equipment, or (d) the ground. This may lead to the causal fault chain shown in Figure II-3 above, potentially resulting in an ignition.

(4) D2d – EFF – Fuse

Fuses are protective devices designed to clear system faults by interrupting fault current and de-energizing circuits downstream of the fuse. Fuses are essentially thermal devices designed to melt at a specified current in a specified time. Fault-clearing times, or the time it takes a fuse to activate, generally depend on both current and time. Faster fault clearing typically occurs for higher levels of fault current, while slower fault clearing occurs for lower levels of fault current.

When the fuse element melts, it must be able to do so without causing catastrophic failure of the fuse itself. Such fuse failures can cause prolonged fault conditions, equipment damage, or ignitions.

(5) D2e – EFF – Insulator and Bushing

Bushing/insulators provide mechanical support to energized conductors and maintain electrical isolation between energized conductors and grounded structures such as poles.

Insulators can fail in various ways. For example, insulators, especially older glass or porcelain insulators, can be broken by contact from a wide range of foreign objects, ranging from hailstorms to gunshots. The mounting part of insulators that connects the insulator to the crossarm can deteriorate over time and break or come loose. The tie that connects the energized conductor to the insulator can also come loose; this can damage the conductor over time or detach completely from the conductor. In any of these cases, the insulator failure leads to loss of mechanical support for the conductor. This causes the conductor to come into prolonged contact with the pole, with other equipment, or with the ground. Any such contact can eventually lead to an ignition.

(6) D2f – EFF – Other

This driver category captures other equipment failure events where field personnel have attributed the event to equipment failure, but the specific equipment detail is not provided.

(7) D2g – EFF – Pole

A pole can fail in many ways. For instance, a pole can fail if it does not meet pole-loading criteria when new equipment is added or if visual damage is identified by field personnel. A pole can also fail if the internal integrity of the pole is compromised due to environmental factors such as decay, fungi, woodpeckers, and insect attacks.

(8) D2h – EFF – Connection devices (Splice/Clamp/Connector)

Splices, clamps, and connectors are three different devices used to connect overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector or clamps. Spans of conductors are connected to other spans of conductor with a splice. These devices can degrade due to exposure to the elements and can be damaged by faults on the circuit. Faults on a circuit and the resulting fault current can cause these devices to overheat and melt, causing the overhead conductor to fall to the ground. Failures of splices can result in a conductor coming down and faulting due to contact with other equipment, objects, or the ground.

(9) D2i – EFF - Switch

A switch is a device installed on a distribution line that sectionalizes portions of the circuit by interrupting or facilitating the flow of power. On an overhead system, it is typically installed on poles. A switch can fail while closed (connecting two portions of a circuit) or in operation (when the connection opens or closes). While closed, degradation in the current-carrying part could overheat and lead to catastrophic failures over time. While in operation, the switch could fail due to operator error or mechanical failure due to misalignment of contacts or loosening of parts.

(10) D2j – EFF – Transformer

Distribution transformers can fail for several reasons. One common reason for transformer failures is heavy transformer loading over extended periods of time. Such conditions cause transformers to heat up. This prolonged loading at or near the transformer's rated loading condition can also shorten the useful life of the insulation material. This increases the probability of failure. This problem is exacerbated during extended heat wave conditions, because the equipment does not have the necessary time to cool.

Historically, SCE has experienced a high number of transformer failures during heat storms. The exterior shell of the transformer can deteriorate over time and leak oil, which can also lead to failure. Moreover, because transformers contain oil, when transformers overheat they can fail violently and lead to an ignition.

c) D3 – Wire-to-wire Contact

Wire-to-wire contact can occur during high winds or during conditions where third parties make contact with poles or conductors. The factors that can contribute to wire-to-wire contact include the phase spacing, pole geometry, and conductor tension on each phase of the circuit. When wire-to-wire contact occurs, fault conditions can damage the conductor and cause conductor failure.

d) D4 – Other/Unknown

The "Other" category includes drivers such as "Contamination," "Utility work/operation," and "Vandalism/Theft." Contamination is a phenomenon typically associated with the insulators that support the conductor in a distribution circuit. Contamination-related flashovers typically begin when some type of airborne contaminant combines with moisture from fog, rain, or dew and collects on the surface of insulators. These contaminants can begin to conduct current across the insulators. Unless corrective action is taken, this current can cause the insulator to not perform as intended, resulting in a "flashover." Such flashovers can cause conductor or insulator damage and can lead to a wire-down. Utility work/operation is associated with ignitions resulting from work performed by the utility, *e.g.*, construction, inspection, or vegetation management. Vandalism/Theft is associated with ignitions resulting from third parties vandalizing (*e.g.*, cutting into) SCE's equipment, or third parties trying to steal equipment such as copper wire.

The "Unknown" category represents events that were not specified at the time of the event, and cannot specifically be attributed to any of the other drivers.

2. PSPS

a) D1 - Environmental conditions (wind and FPI) forecast to meet or exceed activation or de-energization thresholds

The driver to initiate a PSPS event, disseminate customer and public safety partner notifications, and monitor conditions for potential de-energization is driven by, among other things, exogenous wind and other weather-related events that can be forecast over a short time period, generally no more than five to seven days in advance. Therefore, it is crucial for SCE to continue to maintain and develop rigorous weather forecasts. As mentioned in previous sections, SCE de-energization thresholds are based on circuit-specific fuel and wind conditions.[46]

D. Triggering Event

1. Wildfire

As stated in previous sections, a wildfire event is defined as an "ignition associated with SCE's overhead electrical assets and operation in its HFRA." Based on SCE's CPUC-reportable fires and ESIRs associated with SCE's distribution and transmission systems in its HFRA between 2017 and 2021, on average there were approximately 44 ignitions per year associated with SCE's equipment in its HFRA. SCE used these historical counts to develop the triggering event frequencies for the RAMP period of 2025-2028.

2. PSPS

In 2021, SCE derived a 10-year historical climatology of PSPS weather conditions along distribution circuits. The goal was to quantify if recent years are experiencing above- or below-average frequency of fire weather conditions, and to what degree mitigation efforts might alter the

[46] SCE's detailed technical paper, Quantitative and Qualitative Factors for PSPS Decision-Making, can be found at https://energized.edison.com/psps-decision-making.

climatology. While SCE has an extensive weather station network of over 1,500 weather stations,[47] the period of record of these stations is relatively short, and no weather stations were installed prior to 2018. Thus, deriving a climatology that sampled a sufficient amount of weather regimes was not possible using the weather stations alone. Additionally, attempting to compare year-over-year changes in PSPS activity via weather stations was complicated by the fact that new weather stations are continually installed, with some shedding new light on windy areas where no previous record has existed.

To overcome these challenges, SCE used a gridded historical dataset available at a two-kilometer by two-kilometer spatial resolution over the entire SCE territory to derive a historical climatology. The gridded dataset provided consistent data coverage and a sufficient period of length to derive the average number of hours each circuit would have exceeded PSPS criteria in the modeled data using specific thresholds.

SCE then adjusted these thresholds to simulate a fully hardened grid due to the deployment of mitigation activities. The resulting estimates are the number of hours each circuit might exceed PSPS conditions once hardened, assuming average future conditions are similar to historical climatological conditions. (This may be a conservative assumption). For this work, SCE used the 10-year period spanning 2010-2020 to derive the climatology at each weather station point location (as of October 2021) that exceeded PSPS thresholds. SCE then aggregated the climatology to the circuit level.

A few assumptions must be noted on the dataset. The modeled dataset subject to the computational and scientific constraints around weather modeling. The dataset is driven by "observed" historical atmospheric conditions. Terrain and meteorological resolution are constrained to the same computational limitations. The ability to represent complex terrain is limited, as is representation of small-scale weather features that play important factors in determining local wind speeds. See Table II-8 below for the PSPS thresholds.

[47] 1,480 weather stations were deployed by the end of Q1 2022.

Table II-8
PSPS Thresholds

Scenario	**Thresholds Evaluated**
Historical Exceedance	FPI > 12 **AND** (Sustained Wind > 31 MPH **OR** Gust Wind > 46)
Hardened Forecast Exceedance	FPI > 13 in all FCZ zones *except zone 1 where FPI > 12 is used* **AND** (Sustained Wind > 40 MPH **OR** Gust Wind > 58)

The outcome of this analysis was an average annual exceedance of the hardened thresholds of 314 circuit hours, which is a summation of every hour that each circuit exceeded the FPI and wind speeds referenced above, over the course of a year. When applying the average time a circuit has exceeded thresholds historically (*i.e.*, total PSPS outage duration minus restoration time), SCE was able to determine the likely number of circuit outages that would constitute 314 circuit hours. Using average customer impacts per outage and adding in restoration time allows SCE to develop an estimate of scope and duration of PSPS impacts in this scenario.

These estimates are based on the best reasonably available data. Modeled future PSPS frequency could differ from actual conditions, many of which are exogenous.

E. Outcomes and Consequences

1. Wildfire

To determine the discrete outcomes when ignitions occur, *i.e.*, Small, Destructive and Significant Fires, SCE relied on wildfire simulation from the Technosylva consequence module of SCE'S Wildfire Risk Reduction Model (WRRM).[48] Technosylva-based wildfire ignition simulations are used to estimate the natural unit consequences (*e.g.*, structures damaged/destroyed, acres burned,

[48] The model uses input data such as surface fuels with burn scar update, building footprints, population count, SCE's asset information at the structure/pole level, SCE's probability of ignition (POI) for distribution and transmission asset, and SCE's specific 20-year climatology. The model outputs asset-level conditional risk (consequence only) and expected risk (POI x Consequence) and service area-wide asset-level consequence. Outputs are aggregated for all 444 weather scenarios as mean, median, maximum and 90th percentile.

and population impacted) resulting from individual ignition simulations along SCE's overhead assets within HFRA.

Based on these simulations, SCE defines a "Small Fire" as one in which the simulated acres burned result in less than 300 acres in 8 hours along with zero fatalities and no structures impacted. A "Significant Fire" is a simulated fire that burns more than 10,000 acres in 8 hours, and/or resulted in at least one fatality, and/or impacted at least 50 structures. A "Destructive Fire" is a middle outcome, as it represents a simulated fire that burned between 300 acres and 10,000 acres in 8 hours, and/or impacted fewer than 50 structures, along with zero fatalities.

SCE used the definitions above to group the simulated wildfire ignitions and associated circuit segments into three discrete outcomes. This resulting analysis indicates that, on average, 46% of the simulated fires along SCE's overhead assets are considered Small, while the remaining are considered Significant (44%), or Destructive (10%).[49]

SCE used the resulting Technosylva simulated wildfire natural unit consequence information (*i.e.*, acres and structures) to estimate the potential associated safety, reliability, and financial impacts. SCE used a ratio of 256 structures impacted to one fatality, and a ratio of 107 structures impacted to one serious injury, to estimate the safety consequences associated with each wildfire ignition simulation. These data are based on historical information.[50] SCE defined serious injuries and fatalities as those associated with firefighters as well as members of the public physically injured during a wildfire event.

Reliability impact reflects outage events associated with fires. These impacts are represented by the number of customer minutes of service interruptions (CMI). SCE assumes an eight-hour service interruption for each customer account on each circuit impacted by a simulated wildfire event.

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49 Based on the maximum consequence of the weather scenario for that asset over an eight-hour, unsuppressed first burn period.

50 Data based on 2016-2019 fires.

Financial impacts represent those costs associated with damage to physical structures, as well as firefighting suppression costs and land restoration costs. For purpose of this analysis, SCE used a system-wide average estimated structure cost of $940,337 per structure.[51] SCE also used a per-acre fire-fighting suppression cost figure of $876,[52] and a land restoration cost of $1,460 per acre.

2. PSPS

For each of the 26 PSPS events in 2020 and 2021, SCE categorized the number of customers included in each outcome category described below. The outcome percentage was then calculated by dividing the total customers in each outcome bucket by the total customers impacted by PSPS events in 2020 and 2021. (The total customers impacted figure counts a customer more than once if a customer was impacted more than once).

a) O1 - Customers and/or public safety partners notified but not de-energized

Almost 90 percent of the customers that would be affected by PSPS events over the referenced time period (2020-2021) were not actually de-energized. SCE only de-energizes circuits when necessitated by actual FPI and wind speed conditions. And even under those conditions, SCE will attempt to use sectionalization and other PSPS mitigations to minimize the footprint of de-energization. Despite not being de-energized, customers associated with this outcome may be impacted by the very fact that they took steps to prepare for a potential de-energization. These preparations could have included procuring goods and services based on knowledge of the impending event.[53]

b) O2 - Customers and/or public safety partners notified and de-energized

Approximately seven percent of customers fall into this outcome. Customers in this category typically receive several PSPS notifications leading up to the actual time of de-energization. In many cases, they are able to prepare for and mitigate the impacts of de-energization.

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[51] Estimated average structure value is based on the RMS industry exposure database (IED) for SCE's service area.

[52] Suppression costs are based on a five-year average of California's reported wildfire suppression costs from 2016-2020.

[53] By definition, there are zero fatalities and serious injuries for customers and/or public safety partners notified but not de-energized.

Despite these preparations, however, these customers still face reliability and financial impacts. Some customers may have chosen to temporarily relocate to an area outside of PSPS consideration, while others may have proactively procured goods, and/or services to allow them to stay safe in their homes during a de-energization event.

c) <u>O3 - Customers and/or public safety partners de-energized but not notified</u>

SCE has notification protocols in place that are designed to notify all potential customers in scope for a potential PSPS event. However, due to certain circumstances (*i.e.*, due to unforeseen weather conditions, human error, or other factors), 3.6% of PSPS-impacted customers in 2020 and 2021 did not receive notification prior to the de-energization event. (In other words, over 96% of all notification-eligible customers did receive a notification prior to de-energization.)

If a customer has not received a prior notification, the customer is unlikely to activate resiliency plans, seek alternative lodging, and take other preparatory steps to reduce any potential impacts of an outage. Customers in this outcome category are likely to be impacted to a greater degree compared to the other outcome categories.

F. <u>Tranches</u>

1. <u>Wildfire</u>

In the workpapers, SCE tranches wildfire risk at the circuit segment or structure level for all assets in SCE HFRA. For ease of reference and clarity of presentation in this chapter, and in alignment with our Integrated Grid Hardening Strategy, SCE has bundled these tranches into three broad groupings: Severe Risk Areas, High Consequence Segments, and Other HFRA.

Grouping 1: Severe Risk Area

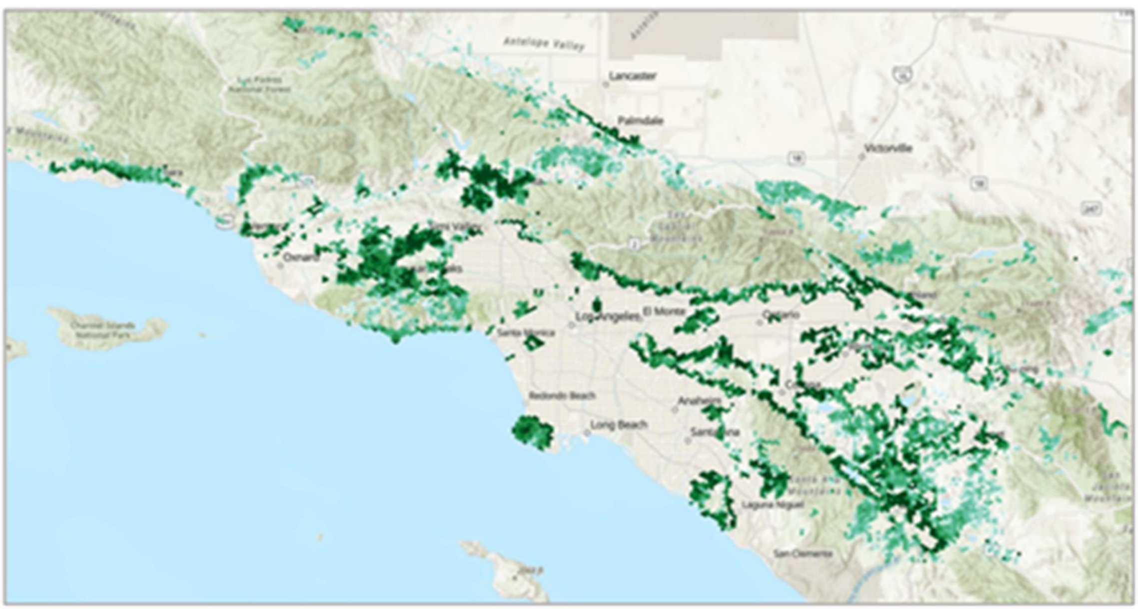
SCE divided its HFRA into equally-sized hexagons, each approximately 214 acres in size. SCE used hexagons[54] given that the distance from the center of a hexagon to all adjacent hexagons is the same distance without any gaps between hexagons. This enabled SCE to compare variables across similar-sized hexagons. From these hexagons, SCE identified Severe Risk Areas as

[54] A hexagon is a six-sided type of polygon.

locations with egress challenges, areas that fires have historically propagated towards (burn-in buffer), areas with extreme high winds, and segments with extreme Technosylva consequence (*i.e.*, greater than 10,000 acres in 8 hours with simulated wildfire ignition consequence).

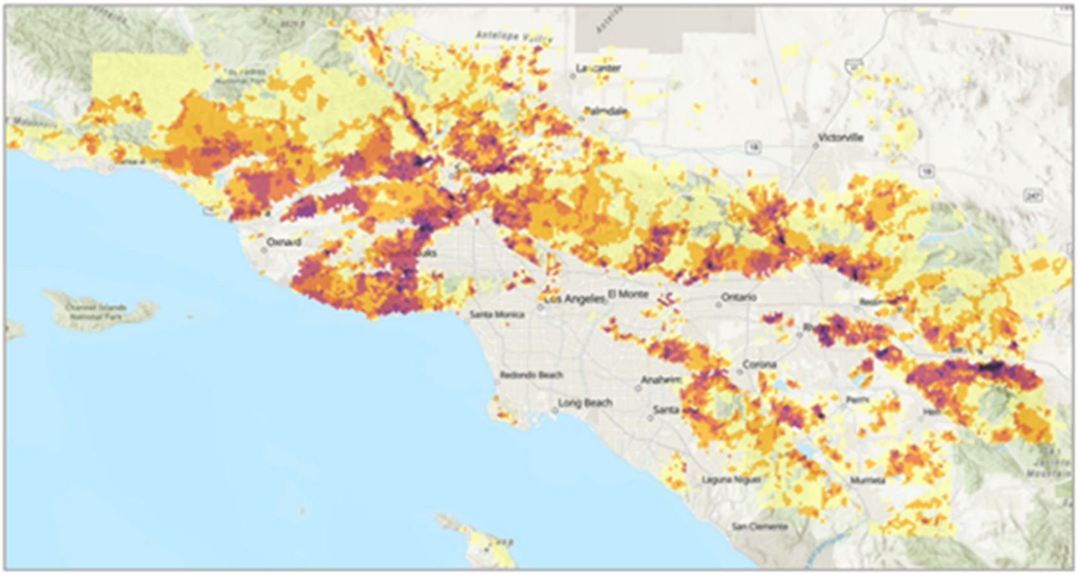
SCE first defined the egress-constrained areas as those with substantial road availability concerns, using a ratio of roads to the population within each hexagon. A lower score indicated fewer miles of roads per person in a given hexagon. This represents a potential egress concern should everyone in the polygon need to evacuate the area simultaneously. Figure II-8 shows areas with egress concerns in green hexagons. The darker green indicates less road availability for egress.

Figure II-8
Egress-Constrained Area



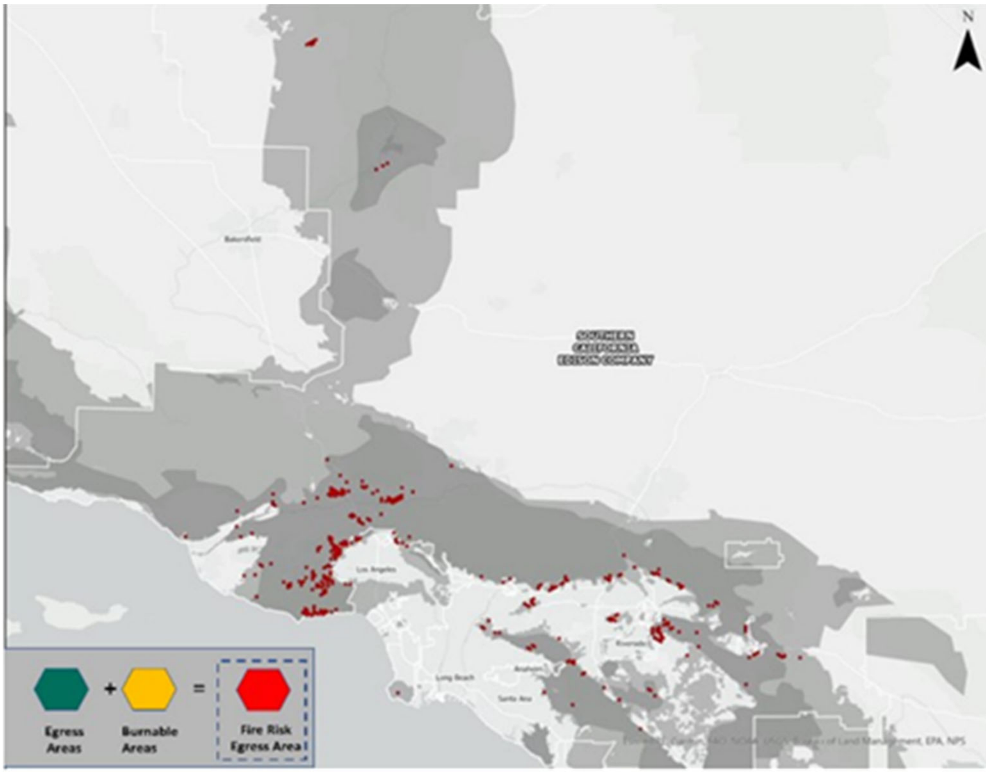
SCE then overlaid the egress-constrained areas with regions that have a high historical fire frequency using fire scars from 1970 to 2020. A higher score indicates a higher likelihood that a given hexagon will burn, meaning fires either originated from or travel into these hexagons (see Figure II-9 below).

Figure II-9
Areas with High Frequency Fires



SCE flagged hexagons with both limited road availability and a high burn frequency as potential Fire Risk Egress-Constrained Areas. Please refer to Figure II-10 below.

Figure II-10
Overlay of Egress-Constrained Areas and High Frequency Burns

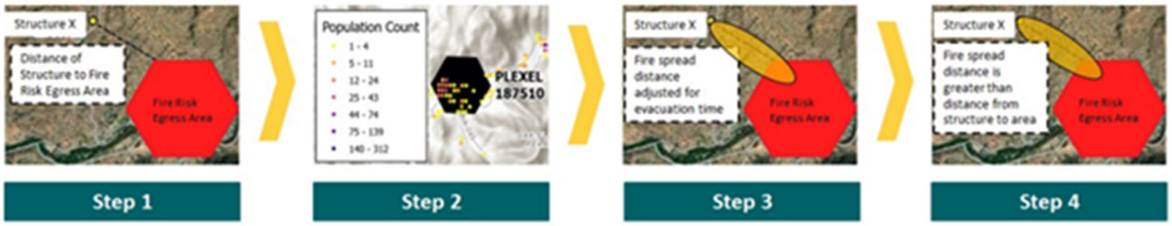


Utilizing Technosylva's simulated wildfire ignition consequence data, SCE determined which overhead structures could have ignitions that potentially result in fires burning into Fire Risk Egress Constrained Areas, potentially trapping the public. Figure II-11 below shows the steps taken to determine this area, which is called the Burn-in Buffer.

- In Step 1, SCE identified all structures within 25 miles of a Fire Risk Egress-Constrained Area.
- In Step 2, SCE calculated the time needed for the population to exit the hexagon using population size, travel speed, and distance to safety.
- Taking into account terrain and other factors, in Step 3 SCE calculated the distance the fire could travel from each SCE distribution overhead structure within 25 miles, in the time needed to evacuate the Fire Risk Egress-Constrained Area.

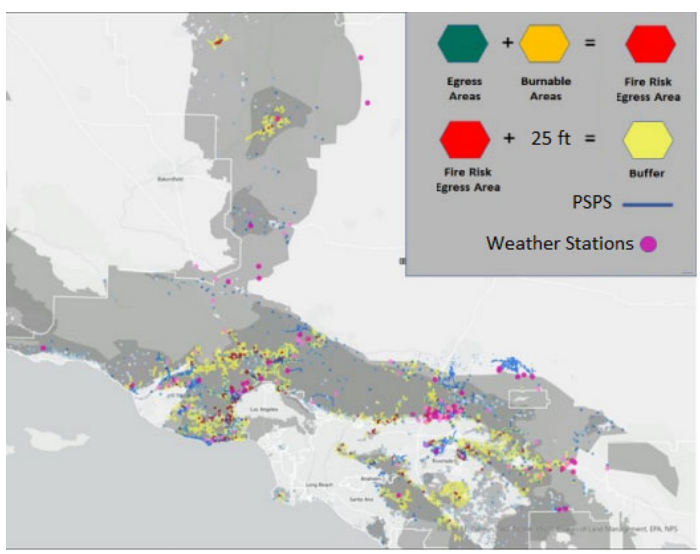
- In Step 4, SCE flagged the structure as a potential burn-in buffer structure if a fire originating there could enter the Fire Risk Egress-Constrained Area, accounting for wind direction, topography, and physical barriers (*e.g.*, lakes).

Figure II-11
Burn-in Buffer



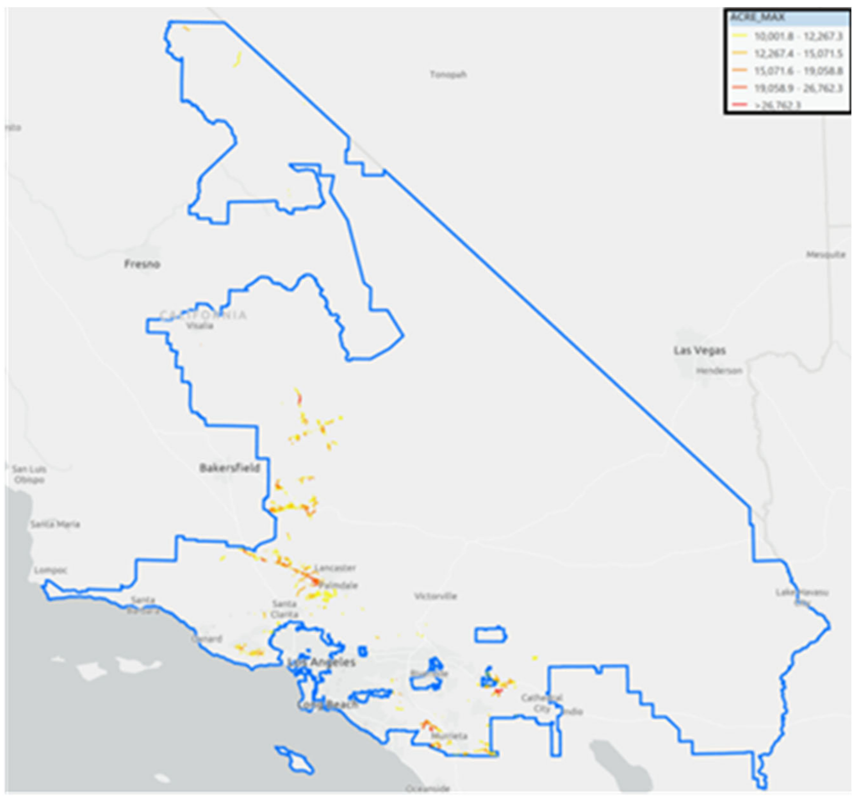
Further, SCE examined historical wind data since 2017 to determine which areas experienced high sustained wind speeds above 40 mph and wind gusts above 58 mph (*i.e.*, SCE's current PSPS de-energization threshold for fully covered isolatable conductor segments) (see Figure II-12 below).

Figure II-12
Areas with Extremely High Wind Speeds



Finally, SCE determined segments in its HFRA that have an exceptionally high consequence in acres burned at 8 hours. SCE used the threshold of at least 10,000 simulated acres burned in the first 8 hours. Historical data shows that some fires that burn over 10,000 acres in the first 8 hours ultimately burn over 100,000 acres.

Figure II-13
Areas with Exceptionally High Technosylva Consequence Scores



SCE aggregated the analyses on egress, burn-in buffer, extreme high winds, and extreme Technosylva consequence to determine the Severe Risk Areas.[55] Of the 9,700 total distribution circuit segment miles within its HFRA, SCE identified approximately 2,275 miles that fall into this category of risk. From these 2,275 miles, SCE removed the following: (a) miles that already have been hardened through installation of covered conductor; (b) miles that are now in the stage of

[55] SCE conducted further review of our segment designations (*i.e.*, Severe Risk Area, High Consequence) in our HFRA after we filed our WMP earlier this year. We have updated some of the designations based upon that additional review.

pre-construction or in-construction for installation of covered conductor; and (c) miles where a high-level scoping review determined that undergrounding is infeasible. This analysis resulted in a scope of approximately 700 miles of unhardened Severe Risk Area by the end of 2023.

SCE plans to mitigate these 700 miles at a prudent pace. As stated above, for purposes of determining the scope of unhardened Severe Risk Areas, SCE removed certain miles based on a high-level scoping review that indicated undergrounding appeared to be infeasible. Once the initial scope of 700 miles was established, SCE then engaged in a second, more detailed review of this more discrete scope to determine feasibility of undergrounding.

This second and more in-depth review was conducted with the regional planners and resulted in the conclusion that within those 700 miles, 100 of those miles were not feasible to be mitigated by undergrounding. Thus, approximately 600 miles are slated for undergrounding, and 100 miles for covered conductor and supplementary mitigation measures (because it is infeasible to underground or due to being sited in urbanized areas). In 2024, SCE plans to underground approximately 20 of those 600 miles and install covered conductor on the 100 infeasible miles located in Severe Risk Areas. This leaves approximately 580 miles of unhardened miles located in Severe Risk Areas by the end of 2024.

Grouping 2: High Consequence Segments

In addition to Severe Risk Areas, SCE identified High Consequence Segments. These are segments in which simulated wildfire ignitions resulted in a wildfire consequence of 300-acres-or-greater in 8 hours,[56] as well as those circuits which have the potential to be frequently impacted by PSPS events. Although Technosylva fire-spread projections rely on an assumed eight-hour burn duration after ignition, the real-world implications of a fire of that size in that time frame may be far more dire. Analysis of more recent fires in California between 2018 and 2020 shows that one out of four fires (25%) that were only 300-999 acres after approximately 8 hours post-ignition ultimately

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[56] CAL FIRE uses the 300-acre threshold for large fires in its annual fire report. The National Wildland Coordinating Group defines a "large fire" as any wildland fire in timber 100 acres or greater and any grassland/rangeland fire 300 acres or greater.

grew to 10,000 acres or more (Figure II-14).[57] Additionally, SCE's analysis of California fires between 2015 to 2019 indicate that number of acres burned is a reasonable and reliable correlated proxy for buildings destroyed. For example, as shown in Table II-9 below, a fire of 10,000 acres or more results in the destruction, on average, of approximately 200 buildings.

Figure II-14
Fire Size at 8-Hours Relative to Final Fire Size

Table II-9
High Correlation Between Final Fire Size and Average Buildings Destroyed

Final Fire Size (Acres)	Average Buildings Destroyed
300-1k	~2
1k-5k	~7
5k-10k	~15
10k-50k	~200
50k+	~1250

In addition, SCE conducted an analysis that identified circuits that have experienced or are expected to experience high customer minutes of interruption (CMI) from PSPS de-energizations,

[57] Data from SimTable https://www.simtable.com/.

absent appropriate grid hardening. SCE included those circuits within the High Consequence Segments category. The analyses on fire propagation and PSPS impacts collectively informed the determination of High Consequence Segments.

There are approximately 4,675 miles that are not included in Severe Risk Areas, but are categorized as High Consequence Segments. From these 4,675 miles, SCE removed already hardened, in-construction, and planned miles for 2023-2024. This resulted in approximately 1,200 miles of unhardened High Consequence Segments scope by the end of 2024. As discussed above in section I.A., SCE proposes to deploy the full suite of CC++ measures on these miles as the preferred mitigation option. Although these miles do not have the risk profiles that would qualify them as Severe Risk Areas (and that would therefore lead SCE to underground them), they are still sufficiently risky so that covered conductor standing alone would be insufficient from a risk mitigation standpoint. The CC++ solution offers additional protection and risk mitigation beyond what covered conductor alone can provide.

Grouping 3: Other HFRA

The Other HFRA category encompasses SCE overhead distribution lines that are located in HFRA but that are neither High Consequence Segments nor Severe Risk Areas. Here, SCE will replace retired or damaged bare wires with covered conductor pursuant to its engineering standards for HFRA locations. Please refer to section I.A. above. Although SCE is not currently targeting proactive hardening of the lines that are categorized as Other HFRA (with the exception of locations where it may be operationally efficient to do so),[58] SCE will regularly re-evaluate risks in these locations based on potential future climate change impacts, refined risk methodologies and modeling, and/or more accurate information. SCE identified approximately 2,750 circuit miles that fall into this category of risk. From these 2,750 miles, SCE removed already hardened, in-construction, and

[58] As referenced in section I.A.2 above, during the course of installing covered conductor through our WCCP, operational considerations are also germane when determining the actual amount of final deployed scope. In SCE's 2021 GRC, the Commission recognized this by authorizing a 20% “buffer” of additional miles when approving a preliminary scope of work. *See* D.21-08-036, p. 200, fn. 669. That buffer will continue to be necessary under SCE’s Integrated Grid Hardening Strategy when addressing spans adjacent to those circuit segments that SCE has determined to be high consequence and/or severe risk.

planned miles for 2023-2024. This resulted in approximately 1,450 miles of unhardened "Other HFRA" scope by the end of 2024.

2. <u>PSPS As a Risk</u>

PSPS risk tranches are defined by the de-energization frequency of individual circuit segments. Because PSPS is relatively nascent at SCE, and because future weather and fire potential is difficult to forecast at such a granular level, past PSPS de-energization is one of our best indicators of potential future impacts. Historical PSPS de-energization frequency is used to prioritize accelerated PSPS-driven grid hardening; here, detailed circuit reviews identify mitigations at a segment level that decrease the likelihood of future de-energization (*e.g.*, covered conductor, undergrounding, switches, weather stations, etc.). For ease of reference and clarity of presentation in this chapter, the RSEs for controls and mitigations that address PSPS as a risk will be shown at the mitigation level.

G. <u>Related Factors</u>

For purposes of this discussion, SCE defines related factors as factors that are not directly included in the risk modeling but can impact the driver frequency and the likelihood of certain outcomes. Related factors for the Wildfire and PSPS risks include, but are not limited to, climate change, extreme weather, contact with energized equipment, and widespread outage. Certain mitigation measures could provide additional, secondary benefits. For example, installing covered conductor also results in a secondary public safety benefit. In addition to reducing ignition risk, covered conductor reduces wire-down incidents and risks from contact with energized downed wire.[59]

III.

<u>WILDFIRE AND PSPS COMPLIANCE ACTIVITIES</u>

SCE defines compliance activities as those that are required by law or regulation. As discussed in Chapter 2 and consist with our approach in the 2018 RAMP, compliance activities are not risk-modeled in this RAMP. In the 2018 RAMP, SCE discussed one compliance activity for Wildfire Risk,

[59] Covering conductor can also provide reliability benefits. Please refer to SCE's Test Year 2021 GRC Track 4 testimony, Exhibit SCE-02, section V.E.1.a.

i.e., Vegetation Management.[60] For our 2022 RAMP, SCE describes compliance activities associated with mitigating wildfire risk below. Chapter 5, Contact with Energized Equipment, discusses other compliance work in SCE's service area which may also serve to mitigate electrical faults, and in turn, potential wildfire ignition risk.

A. CM1 – Routine Vegetation Management

SCE performs Routine Vegetation Management activities to maintain clearances around poles and equipment on the distribution and transmission systems, in order to comply with current regulations and Commission recommendations.[61]

1. Distribution Routine Vegetation Management

This distribution program operates on an annual cycle, using the following cadence: a pre-inspection leading to a prescription (*i.e.*, a mitigation); the completion of the prescription (*i.e.*, trimming and other measures); a job-related quality assurance function performed by an internal SCE arborist; and a program-wide quality control function performed by an independent contractor. In cases where the prescription poses significant changes from previous maintenance activities, a contracted customer coordinator will obtain customer approval.

Historically, SCE trimmed trees at the time of maintenance to a greater distance than the minimal required distance, when feasible, in order to stay in compliance for the full upcoming year. Under SCE's revised vegetation management program and consistent with Commission recommendations in D.17-12-024, SCE has expanded the standard for clearance distance in HFRA at time of maintenance to 12 feet for line voltages between 2.4kV and 69kV. Additionally, SCE has developed a standard of 6 feet in non-HFRA at time of maintenance for line voltages between 2.4kV and 69kV.[62] In some cases, it may be necessary to trim vegetation to a distance greater than the

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[60] *See* SCE's 2018 RAMP Wildfire Chapter 10, pp. 10-22 to 10-27.

[61] *See* D.17-12-024.

[62] The recommended clearance at time of trim in non-HFRA pursuant to G.O. 95, Rule 35, Appendix E is four feet. In SCE's experience, a four-foot clearance at the time of trim is frequently insufficient to maintain the required 18 inches of clearance throughout the ensuing year. Approximately 70% of the tree genera growing adjacent to the SCE system have an average annual growth rate that exceeds three feet.

program standard to manage the growth of the tree or to meet ANSI 300 standards for tree trimming.[63] A certified arborist makes this decision on a case-by-case basis. At times, the customer may have concerns about the tree being trimmed to the recommended distances, and instead opts for a tree removal. In these cases, SCE will offer a replacement tree to the customer.

Beyond routine line clearing, the Distribution Routine program includes two additional components: (1) supplemental patrols and (2) pole clearance/weed abatement. Both programs are related to existing regulatory requirements that have been expanded to address wildfire efforts. Supplemental patrols are treated as verifications to ensure that the requirements of California Public Resources Code (PRC) 4293 – Reliability and PRC 4293 – Clearances are met and maintained. The supplemental patrols occur during the summer months in areas where topography or vegetation conditions are known to pose a threat to SCE's facilities during extreme weather events. Pole clearance is required for non-exempt assets in State Responsibility fire areas. The activity involves maintaining clearances around distribution poles in a 10-foot radial area measured horizontally from the outer circumference of the pole from the ground to a height of 8 feet.

2. Transmission Routine Vegetation Management

The management of vegetation in proximity to Transmission assets closely aligns with the work processes described within Distribution Routine Vegetation Management. One differentiating factor between Transmission lines and Distribution lines is that Transmission lines will sag lower in hot conditions and when more load is carried; and their weight will cause them to sway in windy conditions. This sag and sway movement is commonly referred to as "conductor dynamics." Therefore, SCE's program considers conductor dynamics when defining the location from which minimum clearance needs to be maintained. Consistent with recommended guidance in D.17-12-024, SCE has expanded the standard for clearance distance in high fire areas at time of maintenance to 30 feet for power lines 115kV and above. This distance at time of maintenance represents an increase

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[63] ANSI 300 are voluntary industry standards developed by the Tree Care Industry Association, whose mission is to develop consensus performance standards based to manage trees, shrubs, and other woody plants.

from 2018, when the program standard ranged from 10 to 25 feet and did not completely account for line dynamics.

To help ensure that Right-of-Way clearances fully account for conductor dynamics, SCE utilizes light detection and ranging technology (LiDAR). LiDAR is a surveying method that measures distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor. Differences in laser return times are then used to make digital three-dimensional representations of field conditions at the time of survey. The data is then modeled against engineering information to show the maximum sag and sway of that line, and to indicate where vegetation should be present in relationship to those points. SCE plans to conduct LiDAR inspections on bulk and sub-transmission conductor miles in HFRA to help maintain minimum clearance distances, and to identify potential Subject Trees for assessment under our Hazard Tree Management Program.

IV.

WILDFIRE AND PSPS CONTROLS

In this 2022 RAMP, SCE describes controls as activities performed prior to 2021 to reduce the frequency of the risk materializing, or the impact level of a risk event should it occur. In the 2018 RAMP, SCE listed several controls designed to mitigate wildfire risk. These included the following: Overhead Conductor Program (OCP), operational procedures (such as recloser blocking), and the Overhead Distribution Transformer programs.

Table IV-10 below compares control activities between the Proposed Plan and the Alternative Plans, as described in our 2022 RAMP. A check mark (✓) in the Proposed Plan column indicates that the activity is included in the RAMP period of 2025-2028. A "none" in the Proposed Plan or Alternative Plans columns means this activity is not included for that particular plan in the RAMP period of 2025-2028. A "less," "more," or "same" in the alternative plans represents a comparison of the level of associated activity with respect to the Proposed Plan. "N/A" means the activity sunsets in 2022, 2023, or 2024, and was included in the baseline risk calculations.

Examples of controls include our Wildfire Covered Conductor Program (WCCP), ground and aerial inspections and remediations, and vegetation management work.[64] Some improvements to controls commencing in 2020 (such as ground and aerial inspections and remediations) include the following:

- Inspecting areas that posed increased fuel-driven and wind-driven fire risk primarily due to elevated dry fuel levels (Areas of Concern); and
- Adding enhanced Transmission conductor and splice inspections methods (LineVue, X-Ray and Conductor Sampling) in HFRA to complement existing inspection processes to help prevent future ignitions.

[64] Activities that were in the pilot stage prior to 2021, such as Transmission Open Phase Detection (T-OPD) and microgrids, were also included as controls.

Table IV-10
Wildfire RAMP Controls

2022 RAMP ID	2022 RAMP Control Name	Included in Proposed Plan (2025 - 2028)	Alternative #1 (Compared to Proposed Plan)	Alternative #2 (Compared to Proposed Plan)
C1	Wildfire Covered Conductor Program (WCCP)*	✓	More	Less
C1a	Fire Resistant Poles (FRP)	✓	More	Less
C2	Branch Line Fuses	✓	Same	Same
C3	Remote Controlled Automatic Recloser (RAR)*	✓	Same	Same
C4	Circuit Breaker (CB) Settings	N/A	N/A	N/A
C5	Transmission Open Phase Detection (TOPD)	N/A	N/A	N/A
C6	Tree Attachment Remediation	N/A	N/A	N/A
C7	Microgrids*	None	✓	None
C8	Long Span Initiatives (LSI)	✓	Same	Same
C9	Vertical Switches	N/A	N/A	N/A
C10	Distribution Ground Inspection	✓	Same	Same
C11	Distribution Aerial Inspection	✓	Same	Same
C12	Transmission Ground Inspection	✓	Same	Same
C13	Transmission Aerial Inspection	✓	Same	Same
C14	Distribution Infrared Inspection	✓	Same	Same
C15	Transmission Infrared Inspection	✓	Same	Same
C16	Hazard Tree Management Program (HTMP)	✓	Same	Same
C17	Expanded Pole Brushing	✓	Same	Same
C18	Dead and Dying Tree Removal Program	✓	Same	Same
C19	Expanded Line Clearing	✓	Same	Same
C20	HD Camera*	✓	Same	Same
C21	Aerial Suppression	✓	Same	Same
*This activity impacts both Wildfire and PSPS risks.				

A. <u>Wildfire</u>

1. <u>C1 – Wildfire Covered Conductor Program (WCCP)</u>

We initiated the WCCP in 2018 to address the profound threat that wildfires posed to California. Our WCCP was extensively discussed in our 2018 RAMP. It continues to serve as our primary mitigation activity to reduce wildfire risks in our service area. The WCCP in HFRA includes: (a) deploying covered conductor, along with installing fire-resistant poles (FRPs) (*i.e.*, composite or fire-resistant wrapped poles) when needed to meet loading requirements, and (b) replacing tree attachments with attachments to utility poles.

The covered conductor SCE uses is a conductor that is protected by three layers of insulating material. The design can prevent arcing caused by contact with a tree limb, conductor-to-conductor contact, or contact with a metallic balloon. In addition, while our principal motivation for covering conductor has been and remains mitigating wildfire ignition risk, its installation also has secondary public safety- and reliability-related benefits. Because the covering on the conductor (the "insulation") helps reduce the frequency of contact-related circuit interruptions, installation can lead to fewer wire-down events. Preventing wire-downs has both a reliability benefit and a public safety benefit. Regarding public safety, the insulation can reduce the potential for electrocution even when a wire-down event occurs and where the conductor remains energized (as long as the member of the public only contacts a section of the downed wire that is covered).

In this way, covered conductor also aids in reducing the Contact with Energized Equipment RAMP Risk. In addition, covered conductor is sized to accommodate expected levels of fault current should faults occur, regardless of cause. This also reduces the likelihood of wire-down events. Finally, installation of covered conductor typically occurs simultaneously with other important equipment upgrades that are expected to increase reliability and resiliency, including the covering of jumpers and connections points; the installation of animal protection equipment, fire-resistant poles and composite cross-arms; and other potential equipment improvements.

a) <u>Drivers Impacted</u>

Covered conductor refers to a conductor being "covered" with insulating materials to protect against the impacts of incidental contact. This mitigation is effective at reducing the ignition drivers associated with D1, contact from object (CFO) and wire-to-wire faults. In addition to those drivers, fault conditions can weaken and sometimes cause conductor failures, impacting D2 (equipment/facility failure) and resulting in energized wire-down events. This in turn could result in electrical arcing in the air or on the ground, leading to ignitions. In the case of a downed wire, covered conductor reduces the area of exposed base wire, thus reducing the likelihood of ignition and serious injury or fatality in comparison with contact with bare conductor.

Covered conductor can also help reduce PSPS risks by decreasing the likelihood of de-energization due to higher real-time windspeed thresholds for circuits that are covered. Moreover, on circuits that have been fully covered, there is also a significant improvement in reliability in terms of number of faults compared to bare wire circuitry in HFRA.

b) <u>Consequences Impacted</u>

Programmatically, WCCP does not appear to impact consequences (but please see C1a, below).

2. <u>C1a – Fire Resistant Pole (FRP)</u>

As part of SCE's WCCP, SCE uses FRPs when pole replacements are required to meet pole loading criteria. Composite poles are fiber-reinforced polymer utility structures. They are resistant to corrosion, chemicals, and rot. They are non-conductive and environmentally friendly. When compared to wood poles of the same class and size, composite poles are lighter in weight and have the capacity to carry more loads under emergency conditions.

The fire-resistant wrap is an intumescent (swelling up when heated) grid made of 23-gauge galvanized steel grid coated with a durable intumescent polymer. When exposed to elevated temperatures, greater than 300° F, either from direct flame contact or radiant heat, the wire mesh will expand via its intumescent properties and form a barrier that protects the wood pole. Once a direct flame is removed, the fire-resistant wrap will in effect self-extinguish. SCE's covered conductor systems will be all-covered. This includes wildlife covers on dead-ends, terminations, equipment bushings, and jumper wires.

a) <u>Drivers Impacted</u>

FRPs are effective with D2, equipment/facility failure, since replacing existing poles with FRPs will facilitate the replacement of aged equipment, such as fuse, switch, insulator and bushing, transformer, and wood crossarms. Wood crossarms are replaced with composite crossarms. Additionally, fire-resistant composite poles significantly reduce leakage current on the crossarm, reducing the occurrence of damage due to electrical tracking. The improved crossarm design and reduction of leakage current accounts for the 50% effectiveness against crossarm damage or failure.

b) Consequences Impacted

Installing FRPs, such as composite poles, helps prevent ignitions at the top of the pole and further reduces the reliability impact after a fire. For instance, burned and/or fallen poles can cause other equipment on the pole to fail, making service restoration more difficult following a fire. SCE installs FRPs as needed per pole-loading requirements, in order to withstand a fire, maintain system resiliency, and shorten the time needed to restore service.

3. C2 – Branch Line Fuses

Fuses are safety devices consisting of a filament that melts and breaks an electric circuit if the current exceeds the fuses rating. CLFs for branch line protection are now the standard for SCE's system. As part of our branch line protection strategy, SCE has been replacing conventional fuses since the program commenced in 2018. SCE initially focused efforts on installing fuses at branch lines where fusing did not exist. This was followed by fusing replacements with a focus on CLF technology to reduce fault energy.

SCE's prior fusing mitigation efforts focused on deploying new branch line fuses where fusing did not previously occur. SCE's efforts to replace existing branch line fuses helps reduce fault energy, bring the fuses up to the CAL FIRE "Exempt" classification, and/or replace fuse types identified with operational issues. Existing fuses are typically replaced by CLFs, although larger branch circuits may use other CAL FIRE "Exempt" fuse designs. Branch line protection strategy will reduce the POI associated with CFO and EFF risk drivers. The WRRM is then used to quantify the risk reduction associated with this mitigation.

SCE previously had a fusing program that was originally intended as a mitigation that SCE could complete quickly across HFRA to help reduce wildfire risk. This program proactively installed and replaced fuses. We currently anticipate the program should be completed in 2023. Therefore, it is not being included in this RAMP; any future needs will be addressed as opportunity work under HFRI Remediations. This aligns with SCE's position as stated in its Test Year 2021 GRC Track 3 rebuttal testimony.[65]

The fusing mitigation efforts included in this RAMP forecast are driven by PSPS and Fast Curve. These are strategic installations based on analyzing the worst-performing circuits, and thus differ from replacements driven by moisture-ingress concerns.

a) Drivers Impacted

Arcing and currents associated with faults may produce incandescent particles or create equipment failures which can lead to ignitions. Reducing fault energy can lessen the amount and size of incandescent particles, thereby reducing ignition risk. Additionally, reduced fault energy can also help minimize some equipment failures, such as splices and conductors, which can lead to down wires and the potential for ignitions.

b) Consequences Impacted

Branch Line Protection Strategy does not impact consequences.

4. C3 – Remote Controlled Automatic Reclosers Settings (RAR/RCS)

A recloser is an automatic switch that shuts off electric power when issues occur, such as a short circuit. RARs are reclosers which have been modified to be remotely operated by radio. RARs operate similarly to a substation circuit breaker but are located on distribution lines. Remote Controlled Switches (RCSs) are another, similar type of sectionalization device that help SCE limit PSPS de-energization to fewer and smaller circuit segments. SCE has traditionally installed automation equipment to improve reliability and provide operational flexibility. We have expanded our distribution automation activities as part of our wildfire and PSPS mitigation strategy.

In some cases, Fast Curve settings at the circuit breaker may not be feasible due to construction limitations. One such example occurs when a pole top substation has a limited footprint and cannot accommodate a standard size CB and relay, and requires an RAR instead. Ownership agreements can also represent a barrier to feasibility. An example is when a third-party owns the

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[65] *See* SCE 2021 GRC Rebuttal exhibit, p. 33.

substation and SCE owns the circuit, so SCE can only perform work on SCE's property. SCE will install RARs with FC settings on these circuits. Similar to the fusing program discussed above, the RAR program proposal is PSPS- and Fast Curve-driven.

a) <u>Drivers Impacted</u>

RARs impact D1 (CFO), D2 (EFF), and D4 (Other/Unknown). RARs shut off electric power when faults occur (such as a short circuit) due to vegetation or animal contact. Equipment damage or failure may cause bare conductor to come in contact with each other and can result in a significant amount of overcurrent. In these cases, the FC settings reduce the fault energy to quickly de-energize the line to reduce ignition risks.

b) <u>Consequences Impacted</u>

RARs/RCSs impact PSPS consequences by sectionalizing or dividing the circuit to limit de-energization to smaller segments, thereby reducing the number of customers impacted.

5. <u>C4 – Circuit Breaker (CB) with Fast Curve Settings</u>

A relay is a device designed to trip a CB when it detects a fault. In this context, a fault refers to an electrical disturbance in the power system accompanied by a sudden increase in current. The CB then interrupts the current flow. In other words, it cuts off the power supply to minimize damage to the circuit.

In 2018, SCE initiated a program to deploy FC settings at substation CB relays. This type of setting increases the speed at which the relay detects a fault. SCE developed a plan to upgrade older electromechanical relays with new microprocessor relays, and in some cases update microprocessor relay settings to enable FC settings for the remaining HFRA feeder circuits.

a) <u>Drivers Impacted</u>

CB relays with conventional settings take a certain amount of time to detect and respond to a fault. FC settings reduce fault energy by increasing the speed that a relay can react to most fault currents. This can reduce heating, arcing, and sparking for many faults compared to conventional settings. These replacement and updated devices reduce the POI associated with D1 (CFO), D2 (EFF), D3 (WTW) risk drivers.

b) **<u>Consequences Impacted</u>**

CB FC Settings do not impact consequences.

6. **<u>C5 – Transmission Open Phase Detection (T-OPD)</u>**

Open phase conditions refer to a scenario where one of the three phases is physically disconnected on the transmission system. This could occur due to a loose cable, open phase broken conductor, or hardware/splice failure. An open phase condition that goes undetected may cause the energized conductor to drop to the ground.

In 2019, SCE evaluated the effectiveness of the open phase detection scheme using real-time digital simulation. Test results indicated the technology works as intended; that is, T-OPD was able to correctly identify all broken conductor testing events simulated. Given the favorable pilot results observed in 2020, SCE calculated an RSE for this initiative at the driver and sub-driver level. Though the calculated RSE was relatively low, SCE believes it is valuable to pursue T-OPD in light of the potentially severe consequences of energized down wire incidents on the transmission system.

a) **<u>Drivers Impacted</u>**

T-OPD is a technology that allows de-energization of an open phase (broken conductor) before it could contact a grounded object and trigger a fault event. T-OPD reduces ignition risks associated with the high voltage transmission system. While the frequency of incidents remains relatively lower than those occurring on the distribution system, the consequences of energized down wire incidents on the transmission system can be serious.

b) **<u>Consequences Impacted</u>**

T-OPD does not impact consequences.

7. **<u>C6 – Tree Attachment Remediation</u>**

SCE also performs remediation work when existing electrical equipment, including overhead conductor, is attached to trees. Older construction methods used in SCE's forested service area sought to leverage existing trees to support overhead conductors rather than installing utility poles. These "tree attachments" do not meet SCE's current design standards. The integrity of the trees cannot be verified using inspections and assessment techniques for poles. That is, we cannot drill into the trees, apply preservatives to the trees, and take other inspection measures that we are able to do for poles.

In addition, tree attachments increase the probability of faults and damages from vegetation contact and "fall-ins." Removing the electrical equipment and installing it on a new pole reduces ignition driver risks. In the 2021 GRC Track 1 Decision, the Commission stated that it agrees with SCE that tree attachments present a unique wildfire risk given climate-change driven impacts to forested environments, as well as the increased risk of trees becoming diseased or dying.[66]

a) Drivers Impacted

Tree attachment remediation relocates utility equipment from the tree to a pole to reduce the probability of faults and consequence of a spark close to vegetation. Thus, it addresses the CFO and EFF risk drivers. The majority of tree attachment work is completed with aerial cable, as that is the design standard for areas that have dense vegetation. Aerial cable is a fully insulated conductor, equivalent to underground cable, and can withstand permanent phase-to-phase and phase-to-ground contact. Covered conductor cannot withstand permanent contact from objects. (In this context, the term "permanent" means longer than six months). Accordingly, if the existing tree attachment has aerial cable in good condition, SCE will relocate the aerial cable to a pole instead of installing covered conductor.

8. C7 – Microgrids

"Microgrid" means an interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs.
The microgrid is sited within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid,

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[66] D.21-08-036, p. 205.

or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure.[67]

For RAMP purposes, SCE explored the use of microgrids on nine selected circuits in HFRA that are highly susceptible to PSPS events. Upon further evaluation, three of the nine circuits were selected for cost analysis. The microgrid system was assumed to include solar photovoltaic (PV) arrays as the primary energy source, along with an appropriately-sized battery energy storage system (BESS) designed to provide 24 hours of sustained power to downstream customers. In addition, these facilities are designed to have a backup fossil-based fuel source, such as propane.

a) <u>Drivers Impacted</u>

Microgrids indirectly impact all wildfire drivers, given that primary overhead lines will likely be de-energized if the facility is in use.

b) <u>Consequences Impacted</u>

De-energizations during PSPS events, though necessary to reduce wildfire risks during extreme weather conditions, have adverse impacts on customers. This is particularly true when critical facilities or critical care customers are impacted. Microgrid are designed to maintain system reliability and minimize customer impact during de-energization events.

9. <u>C8 – Long Span Initiative (LSI)</u>

"Long spans" consist of distribution circuits of a certain length, spans with mixed conductor, spans that have a sharp angle, or spans that transition between vertical and horizontal configuration. All these types of long spans can have a higher probability of conductor-to-conductor contact occurring in adverse wind conditions. SCE has used visual ground inspections and currently uses LiDAR to identify potential long span risks on the distribution overhead system and remediate the highest risks after field validation occurs.

SCE completed conductor blow-out studies to evaluate risk factors and determine worst-case conditions that could lead to wire-to-wire contact on over-sagged conductors. In 2020,

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[67] Senate Bill No. 1339. https://lpdd.org/wp-content/uploads/2020/04/20170SB1339_90.pdf.

SCE began using LiDAR on its distribution long spans to identify locations with potential issues and engage in planned remediation of the highest-risk locations upon field validation of the LiDAR results. Options for remediation include line spacers between conductors, alternate construction standards (*e.g.*, ridge pin or box construction), wider crossarms to increase spacing, interset poles, and covered conductor. The type of remediation selected will be determined by the specific conditions associated with each span, as well as the corresponding field conditions.

a) <u>Drivers Impacted</u>

LSI addresses D1 (CFO) and D3 (WTW), which is conductor-to-conductor contact occurring as a result of long spans. The contact between the conductors could potentially lead to an ignition event.

b) <u>Consequences Impacted</u>

LSI does not impact consequences.

10. <u>C9 - Vertical Switches</u>

Vertical switches function as switching points on circuits. The switching points include capabilities for sectionalizing, paralleling, and isolating circuits or circuit segments. Vertical switch designs have three bell crank operating systems. These systems must remain in synch to enable consistent operation and to provide the intended performance rating and capabilities of the switch.

To reduce wildfire risk, SCE is replacing the older vertical switches with new ones that are factory-assembled onto composite crossarms. The new switch designs reduce the probability of incandescent particle generation and address the challenges of consistency in construction and deterioration of wood over time. SCE's vendor pre-mounts vertical switches onto SCE-approved composite crossarms prior to field installation.

a) <u>Drivers Impacted</u>

In SCE's HFRA, replacing wooden-crossarm-mounted vertical switches with composite-crossarm-mounted vertical switches may reduce arcing and spark shower events. This reduces the risk of ignitions from D2 (EFF) that can lead to wildfires.

b) **Consequences Impacted**

Vertical switches do not impact consequences.

11. **C10 – Distribution Ground / C11 – Distribution Aerial**

Detailed inspections serve as one method of identifying potential equipment failures or foreign objects that may contact equipment and result in an ignition. The Commission has recognized this principle and determined that periodic detailed inspections serve as an effective mitigation. Accordingly, GO 165 requires that utilities perform a detailed inspection of their overhead assets at least once every five years. However, there is also a risk that equipment or structure degradation will occur between compliance cycle inspections. Such degradation is often due to natural wear and tear or emergent events such as weather or third-party-caused damages.

In addition, GO 165 requirements are based on safety and reliability, may not necessarily address all potential ignition risks, and are typically performed through ground-based inspections. To address ignition risks more comprehensively, SCE determined that more frequent and ignition-focused risk inspections should be conducted in HFRA beyond GO 165 requirements. Our approach is based on the learnings obtained from SCE's 2019 Enhanced Overhead Inspections (EOI) effort and reflects the fact that wildfire risk has generally increased in recent years.

SCE also determined that aerial inspections could meaningfully supplement ground-based inspections to identify deterioration or unfavorable asset conditions that are not visible from the ground. SCE launched its High Fire Risk-Informed (HFRI) inspections in 2020, leveraging lessons learned from our 2019 EOI and improved risk modeling. SCE conducts HFRI Inspections in its HFRA both from the ground and aerially (using drones and helicopters) to provide a 360-degree view of the assets. Ground inspections help detect equipment/structure conditions that are difficult to identify via aerial inspections, and vice versa. The two forms of inspection complement each other.

Additionally, SCE has continually enhanced its HFRI inspections based on the most current data and ignition risk analysis. For example, in 2020, SCE's Fire Science team identified 17 areas of concern (AOCs) in SCE's HFRA. These were areas that posed increased fuel-driven and wind-driven fire risk, primarily as a result of elevated dry fuel levels. This threat can be magnified during periods of high wind, high temperatures, and low humidity (conditions that were forecast for Fall 2020 in Southern California). The methodology used to identify the AOCs was based on a number of factors, including fire history, weather conditions, fuel type, exposure to wind, and egress.

a) <u>Drivers Impacted</u>

The distribution ground and aerial inspection mitigations are effective at reducing the ignition drivers associated with D1 (CFO) and D2 (EFF). CFOs include vegetation and animal contact for both distribution ground and aerial. EFFs include anchor/guy, conductor, connection, crossarm, fuel, insulator/bushing, lightning arrestor, pole, capacitor bank, switch and transformer damage or failures. Detailed inspections serve as one method of identifying potential equipment failures or foreign objects that may contact equipment and result in an ignition. As noted above, the Commission has recognized this principle and determined that periodic detailed inspections are an effective mitigation.

b) <u>Consequences Impacted</u>

These activities do not impact consequences.

12. <u>C12 – Transmission Ground / C13 – Transmission Aerial</u>

The deterioration of transmission and sub-transmission structures and equipment can lead to faults and ignitions that can have similar impacts as the risks associated with distribution structures. SCE’s Transmission EOI program in 2019 demonstrated that the requirements, scope and frequency of compliance-driven grid patrols and overhead detailed inspections were insufficient in detecting a large number of potential hazards. These hazards, if not remediated, would increase the risk of wildfire ignition in HFRA.

Aerial inspections are typically performed at the same locations as ground inspections. The aerial inspections provide a 360-degree view of the assets to detect equipment/structure conditions that are difficult to discern through ground inspections. The aerial inspection effort also helps us collect valuable data regarding asset conditions. The data can be analyzed, stored, evaluated, and used for risk modeling and asset management activities. Once the need for corrective actions is identified during inspections, timely remediating these conditions is imperative for reducing the probability of faults and potential ignitions, and thereby achieve the ignition driver reduction benefits.

Additionally, SCE has continually enhanced its HFRI inspections based on the most current data and ignition risk analysis. In 2020, SCE's Fire Science team identified 17 Areas of Concern (AOCs) in SCE's HFRA. These were areas that posed increased fuel-driven and wind-driven fire risk, primarily as a result of elevated dry fuel levels. This threat can be magnified during periods of high wind, high temperatures, and low humidity (conditions that were forecast for Fall 2020 in Southern California). The methodology used to identify the AOCs was based on a number of factors, including fire history, weather conditions, fuel type, exposure to wind, and egress.

a) Drivers Impacted

The transmission ground and aerial inspection mitigations are effective at reducing the ignition drivers associated with D1 (CFO), D2 (EFF), and D4 (Other/Unknown); an example of one such driver is contamination. CFOs include vegetation and animal contact. EFFs include anchor/guy, conductor, connection, crossarm and insulator/brushing damage or failures. Inspections identify conditions in need of remediation. Those conditions are then prioritized, and items are remediated before they fail and cause a fault. SCE performs routine inspections of our overhead transmission electrical system in compliance with GO 165. However, in 2019 SCE realized the need to shift towards more risk-informed inspections, and accordingly has increased its historical inspections in HFRA.

b) Consequences Impacted

These activities do not impact the consequences.

13. C14 – Distribution Infrared (IR)

Deteriorated connection points on electrical equipment such as conductors, insulators, splices or connectors can cause localized hot spots. Over time these conditions can lead to failures if left unmitigated and pose ignition risks. Often, the conditions are not visible to the human eye, and can thus go undetected during detailed visual inspections.

a) **Drivers Impacted**

The distribution IR mitigation is effective at reducing the ignition drivers associated with D2 (EFF) including connection, fuse, lightning arrestor, voltage regulator/booster, switch and transformer damage or failure. SCE had benchmarked methods to evaluate distribution overhead lines. We learned that PG&E implemented a successful program that utilized IR technology to detect thermal differences and identify hot splices and connectors that can be leading indicators of asset failure. SCE piloted IR inspections of energized distribution lines and equipment in 2017 and 2018, to help us better understand the effectiveness of such inspections in reducing the risk of conductor failing. Following the pilot, SCE deemed it prudent to inspect all distribution facilities in HFRA over a two-year cycle using the IR technology.

b) **Consequences Impacted**

This activity does not impact the consequences.

14. **C15 – Transmission Infrared (IR)**

Deteriorated connection points on electrical equipment such as conductors, insulators, splices, or connectors can lead to failures and pose ignition risks. These conditions are not visible to the human eye and therefore cannot be detected during detailed inspections. SCE plans to perform IR and corona inspections for 1,000 transmission circuit miles per year as part of this activity, in and adjacent to HFRA.

a) **Drivers Impacted**

The transmission IR mitigation is effective at reducing the ignition drivers associated with D2 (EFF) -- specifically, conductor and connection damage or failures. SCE experienced a number of splice failures in the past. As a result, we initiated these inspections in 2019. Specifically, SCE identified 57 transmission wire-down events that occurred in the last five years throughout the SCE service territory, with most failures attributed to conductor and splices.[68]

[68] For a detailed discussion on distribution wire-down events, including the number of distribution wire-down incidents in the last five years, please refer to Chapter 5, Contact With Energized Equipment (*e.g.*, section I.A. in Chapter 5).

Conductors and splices can fail due to age, weather, contact from object, and other factors that can lead to wire-downs.

To reduce transmission conductor wire-down events, SCE plans to use enhanced inspection methods to identify anomalies and detect any underlying issues in order to replace/remediate conductors and/or splices that have a higher probability of failure. In addition, these methods help capture issues that may not be visibly apparent to the human eye or more basic inspection technologies. SCE is adding enhanced transmission conductor and splice inspections methods (LineVue, X-Ray and Conductor Sampling) in HFRA to complement existing inspection processes. These efforts should help prevent future ignitions.

b) Consequences Impacted

This activity does not impact the consequences.

15. C16 – Hazard Tree Management Program (HTMP)

The Hazard Tree Management Program (HTMP) program identifies, documents, and mitigates trees that are located within the Utility Strike Zone (USZ) and are expected to pose a risk to electric facilities. The approach is based on the tree's observed structural condition, as well as site considerations. The program mitigates 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.

a) Drivers Impacted

HTMP seeks to mitigate the risk of ignition from D1 (CFO), particularly green trees. Analysis of TCCI data revealed that a significant number of faults were caused by green trees "falling in" or branches / fronds from green trees "blowing in" to SCE lines and equipment. These trees were typically outside of the compliance clearance zone. Some visually healthy trees that were far enough from SCE lines and equipment to meet clearance requirements still pose a fall-in risk, depending on the condition of the tree and other site-specific factors. Branches or fronds that are dislodged from trees near electrical facilities also have a high probability of blowing into the lines and equipment, causing faults that can potentially lead to an ignition.

b) **Consequences Impacted**

HTMP does not impact consequences.

16. **C17 – Expanded Pole Brushing**

SCE removes vegetation around selected distribution poles to create 10-foot radial (when attainable) and eight-foot vertical clearance on selected poles in HFRA.

a) **Drivers Impacted**

Vegetation at the base of poles and structures can provide the fuel needed to convert a spark from equipment failure into a fire. This vegetation can also support fire propagation, especially during dry and windy conditions. Additionally, even where the equipment is not the source of the ignition, brush surrounding a pole may catch fire and damage electric assets, impeding power restoration and reconstruction efforts. Cal. Pub. Res. Code (PRC) §4292 and related regulations require utilities in certain areas and at certain times to "maintain around and adjacent to any pole or tower which supports a switch, fuse, transformer, lightning arrester, line junction, or dead end or corner pole, a firebreak which consists of a clearing of not less than 10 feet in each direction from the outer circumference of such pole or tower."

b) **Consequences Impacted**

Expanded Pole Brushing does not impact consequences.

17. **C18 – Dead and Dying Tree Removal Program**

Since 2004, Southern California forests have been devastated both by a bark beetle infestation and persistent rounds of drought. These conditions are interrelated. Accordingly, SCE has and continues to proactively remove dead, dying, and diseased trees that could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent encroachment, large dead or dying trees can be located outside of the right-of-way and fall into power lines. For example, a dead 100-foot-tall tree that is rooted 70 feet from SCE's electrical facilities could fall into those facilities.

SCE uses a contract workforce that surveys and identifies dead, dying, and diseased trees on an ongoing basis. Only trees identified as at risk to contact SCE's electric facilities are added to an inventory for removal. Since trees continue to die as a result of drought, the same geographical areas are patrolled on a quarterly basis to support this program. SCE utilizes multiple contractors to remove dead, dying, and diseased trees.

a) Drivers Impacted

Dead, dying and diseased trees have a high probability of falling. If these trees are within striking distance of SCE lines and equipment, then a tree can cause fault conditions, sparks, and ignitions. SCE removes trees that have a high probability of falling due to drought or other conditions such as insect infestations.

SCE patrols its HFRA several times a year, as conditions warrant, to identify and remove compromised trees. For example, insect infestation can move quickly; trees within a strike distance of SCE overhead facilities that are dead or are expected to die within a year are removed. SCE selects the scope of work for the Dead and Dying Tree Removal Program to focus on areas historically impacted by bark beetle infestations and drought. By eliminating dead and dying trees, SCE is reducing ignition risk caused by D1 (CFO), specifically fall-ins.

b) Consequences Impacted

The Dead and Dying Tree Removal Program does not impact consequences

18. C19 - Expanded Line Clearing

SCE performs enhanced line clearances to mitigate the risk of vegetation contact with energized conductors. The majority of SCE’s routine line clearing is completed pursuant to compliance regulations (*i.e.*, G.O. 95, Appendix E). In addition to this work necessitated by current regulatory requirements, in some cases SCE goes beyond existing compliance regulations and completes expanded line clearing to further reduce ignition risks.

In SCE’s experience, a four-foot clearance at the time of trim is frequently insufficient to maintain the required 18 inches of clearance throughout the ensuing year. Approximately 70% of the tree genera growing adjacent to the SCE system have an average annual growth rate that exceeds three feet. Accordingly, SCE endeavored to achieve clearance margins at the time of trim in the non-HFRA beyond the recommended minimum, in order to ensure regulatory compliance requirements would be met and to reduce ignition risk.

a) Drivers Impacted

SCE performs line clearances to mitigate the risk of D1 (CFO), specifically vegetation contact with energized conductors. The primary risk being mitigated is vegetation contact with energized conductors. For distribution line voltages between 2.4 kV to 69 kV, vegetation can create a risk to SCE facilities when the vegetation is located in grow-in zones (*i.e.*, beneath or adjacent to the conductors), blow-in zones (*i.e.*, within general blow-in proximity to conductors), and fall-in zones (*i.e.*, outside of grow-in but within striking distance of conductors).

For transmission line voltages greater than 115 kV, SCE has a “wire-zone.” This is defined as the area directly beneath the conductors, and it includes the distance of the conductors at maximum sway condition (line dynamics). Vegetation within this zone has the potential to grow-in and fall-in. This creates risk to SCE equipment and facilities.

b) Consequences Impacted

Expanded Line Clearing does not impact consequences.

19. C20- HD Camera

HD camera installations can resolve gaps in SCE’s spatial data and provide improved fire detection capabilities. SCE’s ability to respond to wildfires in its service area requires accurate and timely situational awareness information about the wildfire’s location, spread and proximity to communities, buildings and assets. However, SCE has observed gaps in its ability to view certain parts of its service area where wildfires are more prevalent, including in locations where communities and mountainous terrain intersect. Left unaddressed, these blind spots could compromise SCE’s ability to provide adequate and timely responses to fires. This Control helps address the gaps. For the RAMP period, SCE does not anticipate incremental activity, but will replace HD cameras on an as-needed basis.

a) Drivers Impacted

HD cameras do not impact drivers.

b) Consequences Impacted

HD cameras can help identify incipient stage ignitions and aid in deploying suppression resources, potentially limiting the size and destruction of a wildfire that would otherwise have propagated for a longer period of time before identification and responsive action occur.

20. C21 - Aerial Suppression

SCE currently provides standby costs for aerial suppression resources in its service area to meet fire suppression needs. Since 2017, the increased size and scope of fire activity has created significant resource drawdown of fire suppression resources statewide. With multiple fires occurring at the same time across the western states, resorting to aerial resources has been on the increase in the last several years. Consequently, an increasing number of aircraft normally available to respond to fires in SCE's service area have been deployed to fires outside of SCE's service area. The result is less resources available in SCE's service area. This led to limited availability of fire agency resources, which in turn has hindered fire suppression activities and increased the potential for major wildfires. These developments put SCE's infrastructure and the communities we serve at greater risk. Accordingly, SCE seeks to assist the fire response community by making prudent efforts to acquire additional assets that can be leveraged during the height of fire season.

a) Drivers Impacted

Aerial suppression does not impact drivers.

b) Consequences Impacted

The aerial resources can drop large quantities of water and fire retardant onto fires. This can significantly reduce the consequences of wildfires, particularly wind-driven fires, by limiting their spread.

21. PSPS As a Control to Mitigate Wildfire Risk

SCE's PSPS protocols allow for the proactive de-energization of circuits when extreme weather conditions make the likelihood of wildfire ignition and propagation untenable. When SCE projects that windspeeds will breach circuit-specific thresholds regarding activation and monitoring for potential PSPS, SCE activates its PSPS Incident Management Team (IMT) and commences preparing for the upcoming event (notifications, pre-patrols, and other steps).

The IMT uses a variety of factors to guide its decision on whether or not de-energization on each circuit or circuit segment is necessary, including the FPI and real-time data from weather station sensors and field observers (if available). If de-energization has occurred, then once fire risk conditions subside and field resources validate that conditions are safe, SCE begins patrolling impacted circuits to check for any risks that could potentially present a public safety hazard when re-energizing circuits.

a) <u>Drivers Impacted</u>

Proactive de-energization of a circuit eliminates the possibility of an ignition associated with de-energized utility equipment occurring during the de-energization time period. Please refer to section I.A above for an explanation of why the absence of an RSE for PSPS as an ignition mitigation is consistent with Commission guidance.

Since 2019, SCE's re-energization patrols have identified 94 instances of hazards or damages to de-energized lines; these hazards/damages could have caused an ignition if the line had not been de-energized. Certain hazards may "clear themselves" before SCE can perform a restoration patrol (*e.g.*, vegetation blowing into a line during an event, but then being blown away before the restoration patrol arrives). This means that SCE's identified list of hazards may not be exhaustive.

Because PSPS events are only called during extreme instances of wind conditions, PSPS does not necessarily reduce risks for fuel-driven fires or fires that start under conditions below the PSPS threshold criteria.

b) <u>Consequences Impacted</u>

PSPS does not impact consequences.

B. <u>Public Safety Power Shutoff As a Standalone Risk</u>

Table IV-11 below displays the PSPS controls for the Proposed and Alternative Plans.

Table IV-11
PSPS Controls

2022 RAMP ID	2022 RAMP Mitigation Name(s)	Proposed Plan (2025 - 2028)	Alternative #1 (Compared to Proposed Plan)	Alternative #2 (Compared to Proposed Plan)
C22	Weather Stations	✓	same	same
C23	Customer Resource Centers/Community Crew Vehicle	✓	same	more
C24	Critical Care Backup Battery	✓	same	same
C25	Customer Resiliency Equipment Rebates	✓	same	more
C26	211 Partnerships	✓	same	same
C27	Weather and Fuel Modeling	✓	same	same
C28	Fire Science	✓	same	same

1. C22 – Weather Stations

Weather stations are used to provide critical situational awareness for PSPS decision-making and help improve weather models. Weather conditions can differ significantly at any given time within the HFRA in SCE's service area, due to the large size and diverse topography involved. For example, Southern California's mountains have rapid elevation changes and differing canyon orientations. This creates localized weather zones. SCE needs to monitor and analyze weather data at a granular level across circuits in HFRA to inform critical operational decisions such as deploying PSPS protocols during elevated weather conditions. IMT personnel rely on real-time weather data from weather stations to inform initiation of PSPS events, customer notifications, and de-energization decisions for SCE circuits and circuit segments.

a) Drivers Impacted

Because weather stations can identify differing weather patterns across a circuit, SCE's IMT is able to minimize the PSPS de-energization footprint to only those isolatable segments that are exceeding the wind speed and FPI thresholds. Isolatable segments where wind speeds do not exceed the thresholds can remain energized until conditions change, oftentimes avoiding de-energization altogether.

b) **Consequences Impacted**

Weather stations do not impact consequences.

2. C23 – Customer Resource Centers (CRC) /Community Crew Vehicle (CCV)

During PSPS de-energization events, customers often need access to services such as power sources for the charging of devices and medical equipment, and information on the event such as its duration. SCE provides in-person local support to its customers through Community Resource Centers (CRC) and Community Crew Vehicles (CCV).

CRCs provide services such as access to device charging, restrooms, water, snacks, and resiliency kits. A resiliency kit contains a tote bag, LED lightbulb or flashlight, pre-charged phone battery, ice voucher, and personal protective equipment (*e.g.*, masks, hand sanitizers, etc.).
The contents of the resiliency kits provided to customers may be adjusted as needed. In December 2021, SCE began offering medical thermal bags and ice vouchers for individuals who need to keep medication cool. CRCs also provide an opportunity for customers to sign up for PSPS alerts, update their SCE contact information, and receive answers to questions regarding PSPS, SCE programs, or customer accounts.

CCVs are deployed into the impacted PSPS event areas and supplement our CRCs. SCE uses mobile CCVs as needed to reach affected communities that do not have a CRC location within their community. We also utilize CCVs to supplement CRCs. SCE has designed and outfitted these vehicles with the necessary equipment and technology to enable SCE staff to transport and distribute water, snacks, and resiliency kits to communities potentially impacted by a PSPS event. CCVs can be quickly activated to serve customers and can be set up in open areas without a standing facility and/or in remote areas. CCVs can be especially useful in limiting indoor interactions during critical stages of the COVID-19 pandemic.

a) **Drivers Impacted**

Customer Resource Centers and Community Crew Vehicles do not impact drivers of PSPS. They are simply mitigations activated in response to a PSPS event.

b) **<u>Consequences Impacted</u>**

As mentioned above, Customer Resource Centers and Community Crew Vehicles provide goods and services to customers that the customer may not have or would otherwise have to purchase on their own. Items like small electric chargers, ice vouchers and grocery store gift cards can lessen the burden that de-energization has on a customer. The information provided by trained SCE employees at CRCs and CCVs can also help customers be informed about PSPS protocols, assisting them in terms of preparation for future events.

3. **<u>C24 – Critical Care Backup Battery (CCBB)</u>**

SCE also has a Critical Care Backup Battery (CCBB) program supporting income-qualified customers residing in HFRA who are enrolled in the MBL program.[69] The program provides a free portable backup battery to eligible customers so that they can operate medical equipment during a PSPS event. SCE is sensitive to the impacts that PSPS events can have on our customers, including but not limited to customers that rely on critical life-sustaining medical devices and those dependent on well water pumping. This initiative does not reduce the probability or consequences of ignitions. Instead, it reduces the consequences of PSPS events on customers.

a) **<u>Drivers Impacted</u>**

The CCBB program does not impact drivers of PSPS.

b) **<u>Consequences Impacted</u>**

This initiative was driven by the needs of eligible customers. Under this program, those customers can receive a fully funded battery-powered portable backup solution to operate medical equipment during PSPS activations. In addition, SB 167 authorized electrical corporations to deploy backup electrical resources or provide financial assistance for backup electrical resources to those customers identified as MBL and who meet specified requirements.

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[69] SCE is considering whether eligibility for the program should be expanded by eliminating the income qualification requirement.

4. C25 – Customer Resiliency Equipment Rebates

SCE has developed various programs to provide customers with financial assistance in developing their resiliency to prepare for de-energizations from PSPS and other emergencies. The Portable Power Station Rebate Program promotes resiliency by providing a $75 rebate to customers for purchasing a portable backup battery for use in general home resiliency in the event of an emergency. This program was initiated when SCE identified the need for battery backup to power small appliances including lighting, TVs, routers and modems, as well as the ability to charge devices such as cellphones, laptops and tablets, in the event of an extended outage such as a PSPS event. This program does not reduce the drivers of PSPS but can reduce the consequences of PSPS.

The Portable Generator Rebate program was developed to assist customers residing in HFRA and impacted by a PSPS event. The program offsets the cost of purchasing a portable backup generator. During community meetings facilitated by SCE in 2019 and 2020, specifically in areas dependent on electricity to pump water, SCE learned that some customers may not be able to access water during PSPS de-energizations.

Initially, SCE launched this program in June 2020 by offering a $300 rebate on the purchase of a qualified backup generator, and further enhanced the rebate amount to $500 for income-qualified customers (*e.g.*, those enrolled in CARE or FERA).[70] In July 2021, SCE revised the program eligibility requirements and rebate amounts, based on customer survey feedback. The water pumping-dependency eligibility requirement was removed. Also, enrollment in the MBL program was added to increase accessibility. The rebate was reduced from $300 to $200 to support increased customer participation, since the program was no longer limited to customers dependent on water pumping. MBL customers were added to the eligibility for the $500 rebate, in order to expand accessibility.

a) Drivers Impacted

These programs do not impact drivers of PSPS.

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[70] CARE stands for California Alternate Rates for Energy, and it serves to reduce energy bills for eligible customers. FERA stands for Family Electric Rate Assistance, and it reduces energy bills for qualified households.

b) Consequences Impacted

The Portable Generator Rebate program supports customers by enhancing their resiliency to the impacts of a PSPS event. Without a source of backup power to run select household products or appliances, the burden of PSPS de-energization can be more severe for affected customers.

5. C26 – 2-1-1 Partnerships

D.21-06-034 requires electric IOUs to administer a program to support resiliency for customers with Access and Functional Needs (AFN) in preparation for and during the anticipated duration of a PSPS event.[71] As a result, the electric IOUs developed the PSPS 2-1-1 Service pilot as a statewide solution that provides 24 x 7 live support during PSPS events, providing information and referrals to resources for customers with AFN.

PSPS 2-1-1 Service connects customers with AFN who are experiencing a PSPS event to practical and direct services and support. This includes shelf-stable food, hot meal delivery, transportation, and/or temporary shelter. When not providing assistance during PSPS, the 2-1-1 Service focuses on outreach to at-risk customers, particularly those customers with AFN who are living in SCE's HFRA. PSPS 2-1-1 Service evaluates resiliency plans of customers with AFN, connects them with existing programs that can help them prepare for outages, and assists them in completing applications for SCE programs such as CARE/FERA, and Medical Baseline.

SCE's partnership with 2-1-1 can also connect customers with community-based organizations (CBOs) across SCE's service area. These CBOs offer social services to the community that may mitigate the impact of PSPS (*e.g.*, an organization that could lend a battery in order to power accessible technology, or a food pantry that can help replace food that has spoiled due to lack of refrigeration).

6. C27 – Weather and Fuel Modeling

The Next Generation Weather Modeling System (NGWMS) is an extensive upgrade of SCE's current in-house weather modeling capabilities. The new capabilities allow SCE to make more

[71] *See* D.21-06-034, p. A.10.

targeted PSPS decisions by providing more accurate information about circuits in scope that a potential wildfire may impact. The NGWMS will include weather forecasts and historical weather data spanning the entire SCE service area. Circuit-level forecasts used for PSPS are specific to HFRA and are derived from the initial data that spans the entire territory. Additionally, efforts to equip weather station locations with Machine Learning (ML) capabilities are focused on HFRA.

a) <u>Drivers Impacted</u>

Weather and fuel modeling almost exclusively define the driver for PSPS. Wind and fire potential forecasts define the circuits in scope for an upcoming event. This in turn drives notification processes for those circuits and, eventually, monitoring for potential de-energization.

b) <u>Consequences Impacted</u>

The more accurate that weather and fuel forecasting is, the more likely that SCE can limit PSPS to only the areas experiencing the most concerning conditions. Accuracy would ensure that SCE will have advanced notice for circuits that are eventually de-energized, and will allow for adequate notification to customers prior to de-energization.

7. <u>C28 – Fire Science</u>

SCE's fire science enhancements[72] improve SCE's ability to estimate PSPS impacts, such as the number of PSPS events and the number of circuits that may be in scope for PSPS events. SCE's weather forecasts provide critical information for PSPS events, such as information about whether a circuit will exceed the thresholds necessitating PSPS. This information may inform de-energization decisions, customer notifications, and external coordination, among other uses. Inaccurate or outdated weather models may impact PSPS decision-making by, for example, having a bias or error that impacts the circuits forecast to exceed PSPS criteria.

SCE combines its suite of interrelated forecasting and modeling activities (Fire Potential Index, Fire Spread Modeling, Fuel Sapling, Remote Sensing and Fire Potential Index) into one activity called Fire Sciences.

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[72] The Weather and Fuels Climatology project, along with other projects, help enhance SCE's fire science capabilities.

SCE's current Fire Potential Index (FPI) is modeled after the index developed by SDG&E. Our current FPI was adopted in 2018 and has been used for PSPS decision-making since 2019. In 2019, SCE observed certain limitations in its FPI. That year, SCE added a fuel-loading modifier to account for areas where fuels are sparse and unlikely to support a significant fire. In 2021, SCE calibrated its FPI to SCE's Fire Climate Zones (FCZ). This allowed SCE to raise FPI thresholds across much of its HFRA.

SCE uses advanced fire spread modeling tools—Technosylva's FireCast and FireSim applications—to simulate various scenarios to predict fire ignition and consequence outputs such as fire perimeter size, structures impacted, populations affected, and injury and death. These specific tools are used to support PSPS events and emergency operations, respectively. Additionally, SCE also uses Technosylva as an input to the WRRM. Unlike FireCast and FireSim, which leverage real-time weather data, the Technosylva WRRM leverages a combination of historical information and a forward-looking fuel scenario to estimate the relative risk of wildfire ignition throughout SCE's HFRA.

SCE incorporates information such as fuel conditions in its PSPS decision- making process. Although models can be used to estimate fuel dryness, results from fuels sampling can be used to assess vegetation dryness in near real-time, adjust inputs for fire spread and fire potential calculations, and help "train" live fuel moisture models.

Fuel sampling consists of physically collecting small portions of the native vegetation, which is then brought to a lab to be weighed, dried, and then weighed again to determine the vegetation's moisture content.

SCE uses the data from its fuel sampling to develop and train our artificial intelligence models to approximate live fuel moisture across SCE's service area. This serves as one of the inputs into the FPI. SCE also uses the data to calibrate FPI (thereby enhancing the precision of PSPS decision-making) and to adjust inputs for fire spread calculations (thereby improving the accuracy of fire consequence modeling).

SCE uses remote sensing technology, employing satellite imagery to collect additional information on weather, fuels, and fire activity in order to enhance SCE's overall risk modeling and situational awareness capabilities. Remote sensing, using LiDAR technology, is leveraged to obtain additional elevation information to potentially support de-energization decisions. When circuit level windspeeds are difficult to predict due to complex terrain, developing an accurate picture of this topography can provide better insight into the behavior of the wind across the landscape. This can be particularly useful in locations, such as canyons, where less granular models are not as accurate.

SCE also uses remote sensing technology to assist with early wildfire detection to enable faster fire agency response time. Finally, remote sensing is used to assist SCE with restoration efforts in areas affected by fires/natural events.

a) Drivers Impacted

Fire science improvements help refine modeling and forecasting efforts. This means that PSPS activations are more closely aligned to actual conditions, with the intent that any activation occurs for all areas with sufficiently threatening conditions and occurs nowhere else.

b) Consequences Impacted

The more accurate the forecasting that SCE has, the more accurate and targeted its notifications and de-energization events are likely to be.

V.

WILDFIRE AND PSPS MITIGATIONS

In this section SCE describes a suite of complementary mitigations that were initiated beginning in 2021 to address the segments of its overhead distribution assets in HFRA where ignition has the most potential of growing into a significant wildfire.[73] Table V-12 below shows a comparison of mitigation activities between SCE's Proposed Plan, Alternative Plan #1, and Alternative Plan #2. A check mark (✓) in the Proposed Plan column indicates that the activity is included in the RAMP period of 2025-2028. A "none" in the Proposed Plan or Alternative Plan columns means this activity is

[73] Please note that some of these activities incurred upfront design and planning costs in year(s) prior to 2021, but the actual installation occurred in 2021 or will occur in a later year.

currently not included in that particular plan during the RAMP period of 2025-2028. A “less,” “more,” or “same” in the alternative plans is a comparison with respect to the proposed plan. “N/A” means the activity sunsets in 2022, 2023, or 2024, and was included in the baseline risk calculations.

Examples of mitigations include Targeted Undergrounding (TUG), various technologies that collectively constitute Rapid Earth Fault Current Limiter (REFCL), and fault detection and continuous monitoring devices on circuits. Please note that with the exception of TUG and vibration dampers, the other activities are at the piloting stage in 2021 and/or 2022, and are currently assumed to be deployable by 2025.

A. Wildfire

Table V-12
Wildfire Mitigation Activities

2022 RAMP ID	2022 RAMP Mitigation Name	Proposed Plan (2025 - 2028)	Alternative #1 (Compared to Proposed Plan)	Alternative #2 (Compared to Proposed Plan)
M1	Targeted Undergrounding (TUG)*	✓	None	Same
M2	REFCL – Ground Fault Neutralizer (GFN)	✓	Same	Same
M2	REFCL – Resonant Grounded Substation (RGS)	✓	Same	Same
M2	REFCL – Isolation Transformer (Isobank)	✓	Same	Same
M3	Vibration Damper	✓	Same	Same
M4	Distribution Open Phase Detection (DOPD)	✓	Same	Same
M5	Early Fault Detection (EFD)	✓	Same	Same
M6	High Impedance Relays (Hi-Z)	✓	Same	Same
M7	C-hooks	N/A	N/A	N/A

** This activity impacts both Wildfire and PSPS risks.*

1. M1 – Targeted Undergrounding

Undergrounding of existing overhead power lines consists of digging a continuous trench approximately 24” wide and anywhere from 36” to 62” deep, depending on number of conduits required. Vaults and manholes will be needed at regular intervals along this trench to accommodate cable pulling and electrical connections, as well as any underground equipment being relocated from the overhead system. These structures vary in size from 7’x18’x8’ for the largest vaults to 5’x10’6”x7’ for the smallest standard manhole.

Since TUG is focused on reducing wildfire risk, SCE will only be addressing energized electric conductors. In the future, it is possible that SCE may include communications infrastructure in the program to some degree, based on suitable participation by telecommunications companies. Following the installation of the new equipment, we will remove overhead primary and secondary conductors, as well as any SCE-only poles (*i.e.*, poles not associated with a joint owner).

a) Drivers Impacted

Undergrounding existing overhead power lines greatly reduces the risk of ignitions and outages associated with drivers such as D1 (CFO) (*e.g.*, vegetation, metallic balloons, debris, etc.) and D3 (WTW) faults. In addition to these risk drivers, fault conditions can weaken and sometimes cause electrical stresses on hardware and insulators, which could lead to energized wire-down events or electrical arcing.

Undergrounding is also effective at reducing risks associated with areas that have limited egress routes or areas with dense tree cover. It also reduces the need to resort to PSPS during extreme wind events. While deploying covered conductor may significantly increase the windspeed threshold for de-energization during a risk event, it does not completely prevent de-energizations during extreme wind events. Undergrounding, however, eliminates the need for PSPS events with respect to locations that would otherwise be of concern if not undergrounded.[74]

b) Consequences Impacted

Undergrounding does not impact consequences.

2. M2 – REFCL (GFN, Isobank, RGS)

SCE selected REFCL as a wildfire mitigation initiative because it is a promising solution in reducing energy from ground faults. It works by detecting ground faults as small as a half ampere on one phase in a three-phase powerline. It almost instantly reduces the voltage on the faulted conductor while boosting the voltage on the two remaining phases. Arcing can be extinguished on

[74] In certain circumstances undergrounded sections may be subject to a PSPS event if they are electrically downstream from an overhead circuit that was de-energized.

temporary faults without impacting the customer; this reduces the reliability impact of such sensitive settings. Customers are only disconnected if a fault is found to be permanent.

However, while REFCL is effective at reducing energy from a phase-to-ground fault, it does *not* mitigate phase-to-phase faults. In contrast, covered conductor is effective at mitigating such phase-to-phase faults. Thus, deploying the two mitigations together (where feasible) results in significantly increased mitigation effectiveness compared to either mitigation standing alone.

Additionally, although REFCL technology is compatible with bare wire, covered conductor, or underground distribution systems, it can also come with high cost and complexity. SCE is exploring multiple approaches, because SCE's system is not homogenous and may require different specific configurations in different areas. Thus, assessing the most cost-effective solution will likely vary across SCE's system. In 2022 and beyond, SCE will study how REFCL's mitigation effectiveness complements those of other initiatives to determine prioritization if deploying REFCL projects. Additionally, SCE is exploring how best to manage PSPS de-energization choices in locations that contain REFCL-hardened grid designs.

SCE is assessing three variants of this technology: Ground Fault Neutralizer (GFN), Resonant Grounding Substation (RGS), and Isolation Transformers. Extensive testing of the technology was performed in the Australian state of Victoria to determine the risk reduction that results from using REFCL systems. REFCL's effectiveness appears to be supported by staged fault tests showing that the voltage on the faulted conductor is reduced with sufficient rapidity to prevent the ignitions that the technology is designed to guard against. Based on this testing, SCE preliminarily believes that the various forms of REFCL may be able to reduce ignition risk from phase-to-ground faults by approximately 90%. However, we have further work to do to confirm the effectiveness of REFCL.

Ground Fault Neutralizer (GFN)

Ignitions caused by single phase-to-ground faults can be mitigated with the use of the GFN, which reduces fault energy by a factor of a hundred thousand or more compared to typical utility designs. Australian utilities have demonstrated that GFN has the ability to detect and act upon ground faults as small as a half ampere, making it substantially more sensitive than traditional protection. The first GFN on the SCE system was recently installed at the Neenach substation, with the goal of reducing ground fault energy across the approximately 170 miles of circuitry fed by the substation. Approximately 70 miles are in HFRA. The GFN is equipped with an inverter and is likely to be the preferred REFCL design for large substations, because those systems produce greater fault currents, which then require an additional inverter device to limit the fault energy.

Resonant Grounded Substations (RGS)

Ignitions caused by single phase-to-ground fault can be mitigated by resonant grounding, which reduces fault energy by a factor of a hundred thousand or more compared to typical utility designs. While the energy reduction is less than if a GFN were installed at the same substation, at smaller substations the energy reduction can be sufficient to prevent some ignitions. This project converted Arrowhead substation to resonant grounding to reduce the fault current for single phase-to-ground faults. Compared to GFN, resonant grounding does not include an inverter. This reduces the cost and complexity of the system, but also results in less reduction in the fault current.

The RGS is likely to serve as the preferred REFCL design for smaller substations. Smaller substations produce lower fault current, and resonant grounding alone has been found to reduce fault currents to help mitigate ignitions from ground faults. For the purposes of REFCL systems, the distinction between “large” and “small” substations primarily depends on the lengths of overhead and underground circuitry.

Isolation Transformer REFCL Scheme

Ignitions caused by a single phase-to-ground fault can be mitigated by the application of isolation transformers. These transformers reduce fault energy by a factor of a hundred thousand or more compared to typical utility designs. Costly modifications to underground 4-wire distribution systems can be avoided or minimized when one compares the Isolation Transformer REFCL application to the substation variations for the technology. The Isolation Transformer REFCL scheme represents a cost-effective approach to gain REFCL system protection to circuit-segments. In certain cases, isolation transformer installations reduce requirements for system upgrades to deploy the REFCL system.

This REFCL scheme also can be applicable to overhead isolation transformer installations. These installations have certain limitations when compared to the pad-mounted alternative. The main limitation is smaller-size equipment, which limits the amount of customer load that can be converted to the REFCL scheme. The pad-mounted isolation transformers can be built much larger, and therefore can be applied to serve more customer load. Additionally, they can simplify certain construction and operational practices.

a) Drivers Impacted

A substantial number of public safety hazards from high voltage electrical equipment come from ground faults. These hazards include downed wire incidents, energized conductor contacts (D1 CFO), events involving underground equipment failures (D2 EFF), arc flashes, step and touch voltage incidents, and ignitions. REFCL technology has been found to substantially reduce the energy released in ground faults. It therefore has the potential to significantly reduce these risks. SCE is utilizing its REFCL program in HFRA via several methods to reduce the energy released from ground faults, to help reach the point where an ignition is unlikely.

b) Consequences Impacted

REFCL does not impact consequences.

3. M3 – Distribution Open Phase Detection (DPOD)

This mitigation represents a Distribution Open Phase Detection (D-OPD) scheme to detect one or more open phase (broken conductor) conditions on the distribution system. The advanced protection detection scheme focuses on reducing ignitions associated with wire-down incidents, for both bare and covered conductor systems. The capabilities should allow the protection system to isolate a separated conductor prior to the wire contacting the earth, while leveraging the standard distribution hardware.

SCE will use Remote Sectionalizing Recloser (RSR) and Remote Automatic Recloser (RAR) installations to detect separated conductor(s). The RSR or RAR will be used as the device that will detect when a separated wire event occurs. Once a separated wire event is detected, the RSR or RAR will rapidly communicate to an upstream Remote Automatic Recloser where the protection device will decide to open the recloser and de-energize the portion of the circuit where the separation of conductor occurred. For the pilot, setting configuration changes are made to both locations with the algorithm to detect and isolate separated conductor events. Communication equipment installations are added to both devices in order to allow for direct communication between the devices. The pilot effort will provide SCE valuable information for understanding the potential for additional outages caused by the use of this more sensitive circuit protection system. The costs, functionality, and testing of unknowns (such as interference of other radios) of the new communication components are being evaluated during the pilot.

a) **Drivers Impacted**

D-OPD impacts D1 (CFO), D2 (EFF), and D4 (Other/Unknown). If it proves successful at detecting open phase conditions and isolating lines before the line can contact ground, the D-OPD system is expected to reduce the probability of ignition. The success rate for detecting open phase conditions and isolating lines in the required time is still under review.

Evaluation includes:

- Ability to identify and isolate an open phase condition
- Reduction in number of energized wire-down events
- System reliability impacts from false detections with an operational OPD scheme
- Costs for deploying OPD systems on a broader scale

b) **Consequences Impacted**

D-OPD does not impact consequences.

4. **M4 – Early Fault Detection (EFD)**

EFD technology detects high-frequency radio emissions which can occur from arcing or partial discharge conditions on the electric system. These types of conditions can represent an incipient failure, such as severed strands on a conductor, vegetation contact, or tracking on insulators. EFD shows potential to monitor the overall health of the electric system. This may inform operational decisions during high-risk conditions. The technology requires placing paired sensors on poles approximately every three circuit miles on a distribution line, or placement further apart at higher circuit voltages. Each pair of sensors is able to coordinate to identify the location of the fault more precisely. This pilot project aims to evaluate how effective EFD technology is.

EFD sensors can continuously monitor lines and proactively detect undesirable, degraded, or pre-failure system conditions. If successful, EFD's ability to detect these conditions can translate into assessment of maintenance needs and timely remediations. This should reduce the probability of faults and associated ignitions.

SCE is evaluating EFD's effectiveness by testing the ability of the technology to accurately and expeditiously detect undesirable, degraded, or pre-failure system conditions. The EFD system is considered to have met the accuracy goal of 50% of findings. The continuous monitoring capability of EFD inherently results in identifying findings more quickly than present processes. In fact, EFD can detect undesirable conditions that are not visible with existing practices.

a) Drivers Impacted

EFD impacts D1 (CFO) and D2 (EFF).

b) Consequences Impacted

EFD does not impact consequences.

5. M5 – High Impedance (Hi-Z) Relays

High Impedance Relays utilize multiple protective elements to reduce wildfire ignition risks by detecting High Impedance (Hi-Z) conditions such as downed conductors or arcing events. In lab testing, SCE has demonstrated that the High Impedance Relay technology can detect Hi-Z conditions; however, SCE is still validating the technology's efficiency in the field in detecting actual Hi-Z events.

Detecting Hi-Z conditions is an industry-wide challenge. SCE's traditional feeder protection elements are based on overcurrent. This means that the protection elements rely on fault magnitude to trigger the relay to operate. In a Hi-Z event, however, the fault magnitude is relatively small to non-existent. Therefore, protection schemes that can detect Hi-Z conditions can reduce the propagation of low magnitude fault conditions, and thereby reduce ignition risk. Assessing effectiveness includes reviewing relay event data to determine if the relay alarmed correctly for Hi-Z events.

a) Drivers Impacted

Hi-Z impacts C2 (EFF).

b) Consequences Impacted

Hi-Z does not impact consequences.

6. M6 – Vibration Damper

SCE conducted a study to determine the susceptibility of covered conductor installed between 2018 and 2020 to wind-driven vibration (known as Aeolian vibration). Vibration dampers can stop wind-driven vibration that may lead to conductor abrasion or fatigue over time. This is an issue for both bare and covered conductor. However, covered conductor may be more susceptible to vibration because of the covering's smoothness (perfect cylinder) and the reduction of strand movement due to the covering. If this vibration is not mitigated, the long-term damage may reduce the covered conductor's useful life.

For the study, installations were categorized as high susceptibility, medium susceptibility, or low susceptibility. Risk analysis indicated that targeting high and medium susceptibility areas will provide the best value. High susceptibility areas are near large bodies of water or with flat and open terrain. Medium susceptibility areas are flat, open terrain or residential suburbs with some obstacles (trees, buildings, etc.). Depending on the terrain, the conductors may be exposed to a certain threshold of smooth and low speed winds, which could induce Aeolian vibration on the covered conductor. For areas with more obstacles, this threshold is higher.

Vibration damper retrofits were selected to address the risks associated with Aeolian vibration. Through the susceptibility analysis, we determined the scope for this initiative. This scope and the corresponding useful life were subsequently processed through the WRRM to understand the risk buydown. SCE is pursuing this mitigation as it maintains the useful life of covered conductor to help ensure that the full risk buydown of covered conductor is realized.

a) Drivers Impacted

Vibration dampers impact D1 (CFO) and D2 (EFF).

b) Consequences Impacted

Vibration dampers do not impact consequences.

7. M7 – C-Hooks

In 2021, SCE initiated a program to replace C-Hook insulator attachment hardware from transmission structures in HFRA. A C-Hook is a clamp that holds the insulator to the structure. Though C-Hooks are not part of SCE's construction standards, SCE inherited a limited number of C-Hooks from its past acquisition of the Cal Electric utility. C-Hooks will be replaced with new hardware, insulators, and steel attachments.

In 2019, the EOI program performed aerial captures of all Transmission structures in HFRA, with limited exceptions (*e.g.*, access issues). Inspection surveys were modified to identify C-Hooks as part of the aerial inspection program, as C-Hooks are not tracked in SCE's systems of record.[75] For those structures where the inspector indicated a C-Hook was present, the structures were referred to our Engineering organization for validation and replacement. SCE plans to replace all C-hooks in its service territory by the end of 2023.

a) Drivers Impacted

Replacing C-Hooks addresses D2 (EFF) and contamination, which is in D4 (Other/Unknown) category.

b) Consequences Impacted

Replacing C-Hooks does not impact consequences.

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[75] C-Hooks are classified as B-Materials, which are minor component parts such as insulators, clamps, nuts, and bolts that SCE purchases in bulk and do not require detailed material accounting.

VI.

WILDFIRE AND PSPS FOUNDATIONAL ACTIVITIES

Foundational activities are classified as those efforts that do not directly impact the probability or consequences of wildfire and/or PSPS risk. While SCE engages in activities designed to directly mitigate wildfire and/or PSPS risk, other activities are designed to support and/or enable these direct activities. Some of these supporting activities include providing notifications to customers prior to, during, and after a PSPS event. Another example is fuel sampling, where SCE takes near real-time measurements of vegetation moisture at 15 sites across its service area. SCE's decisions regarding de-energization are informed by this fuel sampling data, which represents near real-time measures of vegetation dryness.

While these types of activities certainly provide indirect benefits by improving our decision-making process, they do not directly reduce either the risk or consequence of wildfire or PSPS. Though they may provide indirect benefits which influence the scope, scale, deployment, and/or prioritization of mitigation activities, this influence is difficult to quantify to any degree. Consistent with Commission guidance, when calculating the RSEs SCE allocates the cost of the foundational activity between each of the enabled activities.[76]

A. F1 – Inspection Wildfire Management (WM) Tools

1. Description

SCE has initiated technology solutions for inspection work and data management to provide inspectors in the back office and in the field with more efficient processes and information. The software solutions aim to better integrate the aerial and ground inspection processes for both Distribution and Transmission. Additionally, the tool is designed to provide information and analytics on field assets across the data collection, inspection, and remediation processes; the tool coalesces this diverse set of material into a single digital platform.

[76] For instance, if the foundational activity's cost is $100 and it enables activity A (which costs $125) and activity B (which costs $125), the $100 cost of the foundational activity would be allocated equally (at $50 each) to both enabled activities, since their individual share of the total is 50%.

In the maintenance/remediation area, SCE will continue implementing software to gain efficiency and productivity, incorporate risk-based inspection plans and field execution, achieve better visibility to system hardening projects (*e.g.*, covered conductor circuit miles) from planning to installation, and improve asset management functions in HFRA. For instance, Inspect Force is a common inspection management solution to support various inspection types (aerial and ground inspections for Transmission assets,[77] post-failure and post-construction asset inspections, etc.). Using this solution will help establish a foundation for sharing work and information across inspections, and should improve the effectiveness and speed of inspections, data quality and record accuracy. These measures will also help ensure that information is available in an accessible and timely manner to support wildfire mitigation activities.

2. Rationale for Considering Foundational

While this activity is critical for driving improvements in precision and accuracy in wildfire and PSPS decision-making, it does not directly reduce either wildfire or PSPS risk, or their consequences.

3. Evaluation for RSEs

A portion of this enabling activity's costs are included within the RSE calculations for each of its enabled activities (namely, distribution ground and aerial inspections and remediations, and transmission ground and aerial inspections and remediations).

B. F2 – Arbora

Arbora is a single, scalable vegetation management solution based on an integrated platform for all vegetation programs. This tool allows SCE and its contractors to more effectively coordinate and execute vegetation management activities.

1. Rationale for Considering Foundational

While this activity is critical for driving improvements in vegetation management activities, it does not directly reduce either wildfire drivers, or its consequences.

[77] SCE is planning to utilize Inspect Force for Distribution assets as well.

2. **Evaluation for RSEs**

SCE has considered the costs of Arbora and has allocated its costs to those related activities, thereby affecting their respective RSEs. Thus, while Arbora does not have a standalone RSE, its impact is considered broadly in all activities it enables. This consists of HTMP, Dead and Dying Tree Removal, and Expanded Line Clearing.

C. **F3 – Community Meetings**

1. **Description**

SCE holds wildfire safety community meetings to share information regarding PSPS, emergency preparedness, and SCE's grid hardening progress. These meetings offer participants a chance to ask questions of SCE staff and share feedback and concerns. SCE's presentations have covered the following areas: wildfire mitigation and PSPS action plans; the PSPS decision-making process; grid hardening, including expected PSPS improvements; PSPS notifications; customer care programs; and community engagement.

2. **Rationale for Considering Foundational**

While this activity is critical for driving improvements in precision and accuracy in wildfire and PSPS decision-making, it does not directly reduce either wildfire or PSPS drivers, or their consequences.

3. **Evaluation for RSEs**

Community meetings are enabling activities for customer support programs, including CRC/ CCVs, CCBB and rebates. SCE has included the costs of the community meeting efforts in the RSE calculations for the programs that the meetings assist.

D. **F4 – Marketing**

1. **Description**

SCE's multilingual marketing campaign, which includes radio, digital, social media, search ads, and direct customer mailings, seeks to educate customers and the public on PSPS, including the conditions that trigger a PSPS, how to prepare for a PSPS, what SCE has done and continues to do to mitigate the risk of wildfires, and how to prepare for emergencies. The marketing campaign seeks to educate customers about PSPS and emergency preparedness and reduce the impact of a PSPS or a wildfire primarily through three methods: (1) advertising campaign; (2) social media; and (3) direct customer mailings.

1. **Advertising Campaign:** The advertising campaign aims to convey key messages that collectively help educate customers regarding PSPS and emergency preparedness. These advertisements run on a variety of channels, including print/newspaper, digital banners, digital video, connected TV, social media, search, digital audio and broadcast radio. The 2021 advertising campaign centered on four message themes: Emergency Preparedness, PSPS Definition/Condition, Wildfire Mitigation, Alert Sign-Up, MBL Program, and Customer Resources and Support. The 2021 ad campaign generated about 832 million total impressions. In 2022, SCE will run its in-language and English advertisements concurrently on an area-wide basis.
2. **Social Media**: SCE uses social media as part of its marketing campaign with paid and organic posts informing customers about PSPS, providing emergency preparedness tips, explaining how to sign up for PSPS alerts, and sharing information on SCE's wildfire mitigation efforts. Also, information about SCE's CCVs and CRCs is placed on Facebook, Twitter, Instagram and Nextdoor.
3. **Direct Customer Mailings**: As part of the direct customer mailing strategy, SCE sent the 2021 PSPS Newsletter to all SCE customers in both HFRAs and non-HFRAs in April and May of 2021, with content adjusted for those customers located in HFRA. Like the 2020 newsletter, the 2021 edition for customers in HFRA focused on PSPS. The newsletter communicated information regarding SCE's decision-making factors for PSPS, and shared material regarding available customer programs and rebates.

Customers in non-HFRA received materials focused on emergency preparedness, which also included an overview of PSPS. Both versions of the newsletter provided an update on SCE's wildfire mitigation efforts, directed the reader to helpful emergency preparedness websites, and provided guidance on ways to sign up for alerts and customer support programs. Translated versions of the HFRA and non-HFRA PSPS Newsletters in all 19 prevalent languages are accessible to customers via SCE's recent "Wildfire Communications Center" webpage (referred to in previous filings as "Multicultural Communications Center"). This webpage launched in April 2021.

2. Rationale for Considering Foundational

While this activity is critical for driving improvements in precision and accuracy in PSPS and wildfire decision-making, it does not directly reduce either wildfire or PSPS drivers, or their consequences.

3. Evaluation for RSEs.

SCE has included the costs of these efforts in the various RSE calculations for activities they support, including CRC/ CCVs, CCBB and rebates.

E. F5 – PSPS Research and Education

1. Description

This activity captures customer feedback on SCE's broad WMP initiatives, with a special emphasis on PSPS activities. SCE seeks to improve its understanding of how it can make adjustments to reduce the impacts of wildfires, PSPS, and wildfire mitigation work on customers. SCE develops surveys which capture customer feedback on areas of interest. We currently conduct the following four surveys:

The PSPS Tracker is an annual survey conducted at the end of wildfire season to assess and understand customer awareness, experience and opinions of SCE's PSPS and wildfire mitigation activities, focusing on customers affected by PSPS events. Five customer segments are targeted:

- Customers not notified but de-energized
- Customers notified and de-energized
- Customers notified but not de-energized
- Customers not notified and not de-energized
- Customers who do not live in an HFRA

Wildfire Safety Community Meeting Surveys are conducted among attendees of the meetings. Here, we receive feedback on the attendees' experience and their perceptions of the information provided.

CRC/CCV Visitor Surveys are conducted among customers who visited a CRC/CCV during a PSPS event. In this way, we receive feedback on their experience, and their comments on the resources and support provided.

In-Language Wildfire Mitigation Communications Effectiveness Surveys are aimed at measuring the effectiveness of communications and outreach prior to and coincident with the wildfire seasons. These surveys utilize different prevalent languages to foster inclusiveness.

2. Rationale for Considering Foundational

While this activity is critical for driving improvements in precision and accuracy in wildfire and PSPS decision-making, it does not directly reduce either wildfire or PSPS drivers, or their consequences.

3. Evaluation for RSEs

SCE has included the costs of these efforts in the various RSE calculations for the activities they support, including CRC/ CCVs, Customer Resiliency Equipment Rebates and 2-1-1 partnerships.

F. F6 – Wildfire Safety Data Mart and Portal (WiSDM)

1. Description

SCE is in the process of implementing a scalable, cloud-based, and geospatially enabled centralized wildfire data repository (or "data mart"), aligning with the Wildfire Mitigation Capability Maturity Model for Data Governance. This data mart is intended to consolidate datasets from federated data sources.[78] The WiSDM is a centralized repository of wildfire datasets to support comprehensive analysis, data utilization across wildfire programs, and wildfire data portal capabilities for reporting and secure data sharing.

[78] Consolidation and normalization of all the data from different sources to a common platform.

2. Rationale for Considering Foundational

While this activity is critical for driving improvements in precision and accuracy in wildfire decision making, it does not directly reduce either wildfire drivers or its consequences.

3. Evaluation for RSEs

SCE has included the costs of these efforts in the various RSE calculations for the activities they support, including situational awareness, grid hardening, asset inspections, and vegetation management activities.

G. F7 – Ezy

1. Description

SCE is currently in the process of implementing a Cloud Big Data and Artificial Intelligence platform (Ezy Data) enables SCE to (a) effectively intake, organize, store, analyze, and visualize remote sensing Big Data collected for wildfire mitigation initiatives and (b) enable SCE's data scientists to develop, train, test, and deploy ML models within business processes.

2. Rationale for Considering Foundational

While this activity is critical for driving improvements in precision and accuracy in wildfire decision making, it does not directly reduce either wildfire drivers or its consequences.

3. Evaluation for RSEs

SCE has included the costs of these efforts in the various RSE calculations for the activities they support, including LSI, asset ground and aerial inspections, and infrared inspections.

VII.

PROPOSED PLAN

A. Wildfire

1. Overview

Since the devastating California wildfires that occurred in the last half of 2017, SCE has been enhancing its approach to reducing the risk of ignitions associated with utility equipment. Over the last several years, it has become apparent that the magnitude of wildfire risk associated with significant portions of SCE's service areas is unacceptable and continuing to grow. Accelerating climate change, with associated extreme weather events and pervasive drought, as well as the continued expansion and migration of Californians into the wildland-urban interface, has made it imperative that SCE do everything within its reasonable control to mitigate the risk of catastrophic wildfires associated with its overhead lines.

Historically, these overhead line assets are linked to the majority of ignitions and ignition risk associated with SCE's utility equipment. Given finite resources and other constraints, SCE uses a risk-prioritization methodology to inform the deployment of mitigations in the riskiest parts of its service area, as defined by the Commission's HFTD maps. From a relative risk perspective, it is appropriate to prioritize work in the very riskiest areas using the most effective and expeditious mitigations. Recent wildfires, however, have demonstrated that the level of *absolute risk* across California and the West may require actions beyond the utilities' short- and medium-term risk mitigation plans. Absolute risk refers to the actual consequences of a fire, including the safety of adjacent population centers as well as property.

For example, in 2021 the Dixie Fire burned for months and became the largest single wildfire in California history. The total area burned amounted to almost a million acres – an area larger than the state of Rhode Island – across the crest of the Sierra Nevada mountains. On December 30, 2021, an unprecedented wildfire broke out in suburban Boulder, Colorado, spreading with devastating speed and destroying more than 1,000 structures. Both of these events demonstrate that the level of absolute wildfire risk on the system – including potentially in areas that may not currently be designated as HFTD – is beyond what can be mitigated and addressed in a single GRC cycle.

SCE's Proposed Plan in this RAMP is designed to address wildfire risk while also balancing risk reduction, cost, execution feasibility, and technology advancements through the 2025-2028 GRC funding period. This plan is built upon SCE's Integrated Grid Hardening Strategy as described in its 2022 WMP Annual Update. The strategy expands upon the risk modeling advancements made since SCE's 2018 RAMP report, and incorporates a highly granular, data-driven, and multi-factor risk assessment framework that informs how much the scope should be, which mitigations should be deployed, where they should be deployed, and how expeditiously they should be deployed throughout SCE's HFRA. This level of targeted risk analysis and mitigation selection will help drive efficient allocation of resources to mitigate risk in the most effective manner.

For the 2025-2028 RAMP period, SCE's Proposed Plan appropriately balances necessary grid-hardening risk-reduction work with the resulting bill impacts customers will experience when these investments are approved in SCE's forthcoming 2025 GRC. In the end, the scope of work SCE proposes here for the RAMP period is fundamentally grounded in the risk-informed decision-making framework that the S-MAP settlement requires. Simply put, SCE's proposed scope of grid hardening work over the 2025-2028 period is designed to continue to reduce ignition risk related to our assets in order to keep our customers and communities safe. As discussed below, SCE can and will execute on the Proposed Plan (based to some extent on anticipated OEIS and Commission guidance and approvals in the WMP process and the TY 2025 GRC, respectively).

As described in II.F.1 above, SCE assessed and divided its HFRA into three groupings: Severe Risk Areas, High Consequence Segments, and Other HFRA. SCE utilized the decision tree in Figure VII-15 below to determine the appropriate mitigation strategy in this Proposed Plan.

Per the decision tree shown below, if the circuit segments are located in a Severe Risk Area and are not already hardened, then SCE determines whether it is feasible to underground.
If feasible, SCE will underground the segments. If not, SCE will harden with covered conductor and

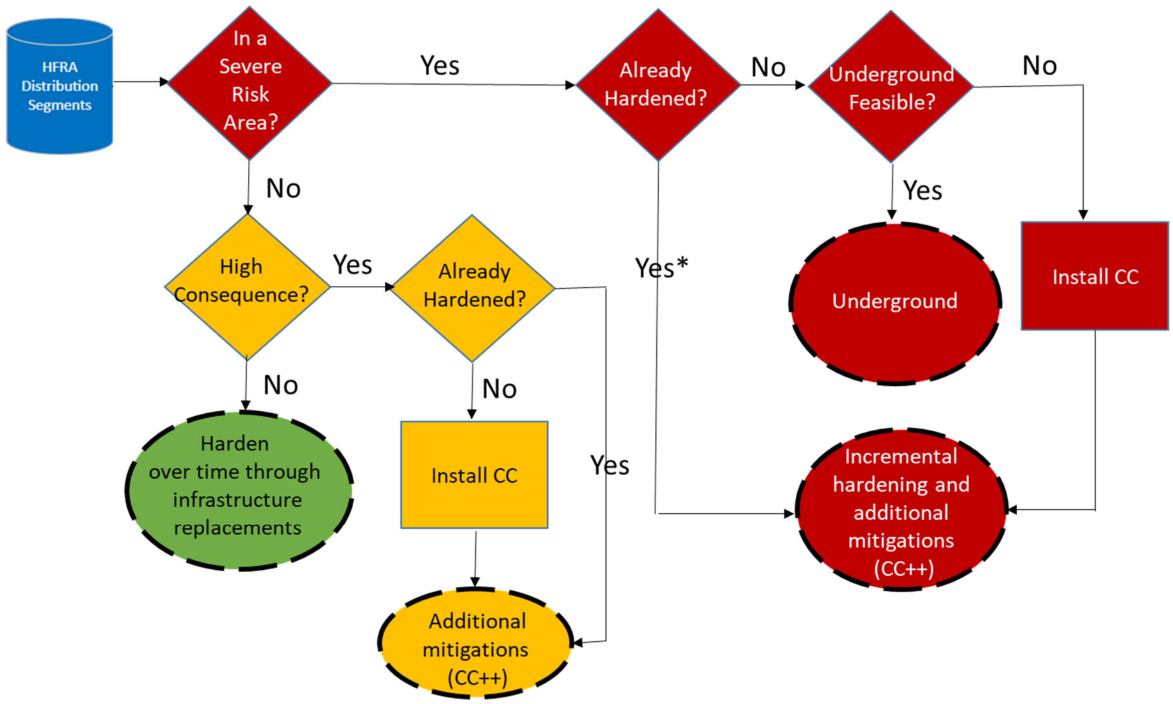
perform additional mitigations, such as asset and vegetation management. For segments already hardened in Severe Risk Areas, SCE will add additional mitigations.[79]

If the circuit segments are not in Severe Risk Areas but are in High Consequence Segments, and are also not already hardened, SCE will install covered conductor. All segments in this case will also receive the additional mitigations of the approach designated as CC++.

If circuit segments are not located in a Severe Risk Area and do not meet the High Consequence criteria, then they are considered as "Other HFRA" and will be hardened over time through other infrastructure replacement programs (including storm rebuilding work as necessary).

[79] While in most cases SCE will add additional mitigations that are complementary to the existing covered conductor installation in these areas, under certain conditions and in limited situations the most appropriate permanent grid hardening solution for selected existing hardened installations may be undergrounding. This is particularly relevant in light of the increasing risk profile of the system due to accelerating climate change.

Figure VII-15
Integrated Grid Hardening Strategy - WF Proposed Plan



* Because of the uncertainties associated with accelerating climate change and changing risk profiles, in certain cases, SCE may need to underground specific circuit segments that were already hardened with covered conductor to further reduce risk and protect SCE's customers. At this time, SCE expects such occurrences to be the exception and not the rule.

Under the Proposed Plan, SCE proposes the planned scope (see Table VII-13) as well as associated costs and risk mitigated through the end of 2028 (see Table VII-14). As discussed in detail in earlier sections, during the 2025–2028 period, SCE proposes to underground approximately 600 circuit miles and install covered conductor on another 1,250 circuit miles in order to address Severe Risk Areas and High Consequence Segments plus buffer miles in Other HFRA.[80] SCE also proposes to install various REFCL technologies on our substations/pole tops covering approximately 2,900 circuit miles.

Additionally, SCE proposes to continue to perform asset inspections and remediations as well as vegetation management in its HFRA over the 2025-2028 period. Please note that the costs outlined here do not take into account potential O&M cost savings from reduced vegetation management activities that are the result of TUG installations. SCE is currently in the process of

[80] Please refer to earlier discussion of buffer miles, including in section I.A.2.

completing an analysis regarding the impacts of grid hardening work on inspections and maintenance and vegetation management costs. To the extent that the analysis ultimately demonstrates potential offsetting cost savings, these estimates will be reflected in the forecasts set forth in SCE's Test Year 2025 GRC application.

Table VII-13
Wildfire Proposed Plan Activities 2025-2028 (Units)

2022 RAMP ID	2022 RAMP Control Name	Type	2025	2026	2027	2028	Total 2025-2028
C1	WCCP	circuit miles	850	300	50	50	1,250
C1a	FR Poles	structures	9,945	3,510	585	585	14,625
C2	Branch Line (Fuses)	circuit miles	45	45	45	45	180
C3	RAR	circuit miles	282	282	282	282	1,128
C6	Tree Attachment Remediation	structures	800				800
C8	Long Span Initiative	structures	7,068	0	0	0	7,068
C10	Distribution Ground	structures	12,460	12,460	12,460	12,460	49,841
C11	Distribution Aerial	structures	4,609	4,609	4,609	4,609	18,435
C12	Transmission Ground	structures	1,593	1,593	1,593	1,593	6,372
C13	Transmission Aerial	structures	503	817	817	817	2,955
C14	Distribution Infrared	structures	28	28	28	28	112
C15	Transmission Infrared	structures	2	2	2	2	8
C16	Hazard Tree Mitigation Program	structures	14,850	14,850	14,850	14,850	59,400
C17	Expanded Pole Brushing	structures	119,900	119,900	119,900	119,900	479,600
C18	Dead and Dying Tree Removal Program	structures	12,442	14,930	17,916	21,499	66,787
C19	Expanded Line Clearing	structures	166,714	166,714	166,714	166,714	666,856
C21	Aerial Suppression		9,689	9,689	9,689	9,689	38,757
M1	Targeted Undergrounding	circuit miles	65	180	240	200	685
M2	REFCL (Total)	circuit miles	1,100	1,100	350	350	2,900
M3	Vibration Damper	circuit miles	31	31	0	0	63
M4	DOPD	circuit miles	228	228	228	228	912
M5	EFD	circuit miles	810	811	810	810	3,241
M6	Hi-Z	circuit miles	296	296	297	296	1,186

Table VII-14
Proposed Plan (Total Costs Nominal $000s and 2025 Risk Spend Efficiencies)

2022 RAMP ID	2022 RAMP Control Name	Total Cost Estimate ($000s) (2025 - 2028)	2025 Risk Spend Efficiencies T1 - Severe Risk Areas	T2 - High Consequence Segments	T3 - Other HFRA
C1	WCCP	$ 751,437	1,565	2,021	628
C1a	FR Poles	$ 49,059	68	55	34
C2	Branch Line (Fuses)	$ 6,074	4,009	3,524	3,812
C3	RAR	$ 15,832	4,207	7,147	2,920
C6	Tree Attachment Remediation	$ 27,479	6,717	6,717	6,717
C8	Long Span Initiative	$ 30,052	1,525	1,673	1,506
C10	Distribution Ground	$ 385,346	246	247	229
C11	Distribution Aerial	$ 159,171	70	69	66
C12	Transmission Ground	$ 95,844	-	603	568
C13	Transmission Aerial	$ 66,909	-	215	215
C14	Distribution Infrared	$ 1,843	1	1	1
C15	Transmission Infrared	$ 991	-	0.0	-
C16	Hazard Tree Mitigation Program	$ 193,007	19	19	19
C17	Expanded Pole Brushing	$ 31,617	3,208	2,286	1,013
C18	Dead and Dying Tree Removal Progra	$ 200,033	23	22	22
C19	Expanded Line Clearing	$ 187,317	470	305	148
C21	Aerial Suppression	$ 73,934	4,120	2,825	787
M1	Targeted Undergrounding	$ 3,098,420	449	-	-
M2	REFCL (Total)	$ 204,688	26,186	25,355	21,998
M3	Vibration Damper	$ 3,464	146	145	28
M4	DOPD	$ 6,785	7,382	5,720	3,018
M5	EFD	$ 51,081	1,917	3,140	716
M6	Hi-Z	$ 5,428	4,623	3,438	2,083
Total		$ 5,645,812			

The pre- and post-LoRE, CoRE and risk scores for the Proposed Plan are summarized by tranche below in Table VII-15.

Table VII-15
Pre- and Post- LoRE, CoRE and Risk Scores

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Wildfire - All HFRA	32.5	1.5	47.6	27.3	1.4	39.6
T1 - Severe Risk Areas	4.3	3.6	15.4	2.7	4.5	12.2
T2 - High Consequence Segments	13.5	2.2	29.3	10.9	2.3	24.7
T3 - Other HFRA	14.8	0.2	2.9	13.8	0.2	2.7

2. <u>Execution Feasibility</u>

An important feature of the selection process is obtaining an early understanding of the feasibility of implementing an initiative, and the time required to plan, design and ultimately deploy the initiative. Given SCE's focus on expeditiously reducing wildfire risk, our preference has leaned toward initiatives that can be deployed quickly. However, SCE also carefully considers the time to design, deploy and obtain permits for certain mitigations. We realize that certain activities may take more time to deploy but are necessary to provide long-term risk reduction.

We realize that some of the mitigations, namely TUG, have not been previously executed by SCE at the scale proposed in this plan. But SCE has obtained experience in deploying Rule 20A undergrounding projects as well as a discrete amount of TUG miles installed in 2021. Accordingly, SCE estimates the time required to underground overhead facilities for each phase of work as shown in Figure VII-16 below. The process of undergrounding overhead electrical distribution assets requires an estimated timeframe of 25 – 48+ months from initial scoping to in-field project completion.[81] The execution phase accounts for approximately 30% of the total project time. Depending on the scope and location of the project, community outreach may be required, similar to the deployment of covered conductor.

There are also numerous other resources that are needed to support project execution. For example, these resources are needed to schedule outages if an outage is required to perform the

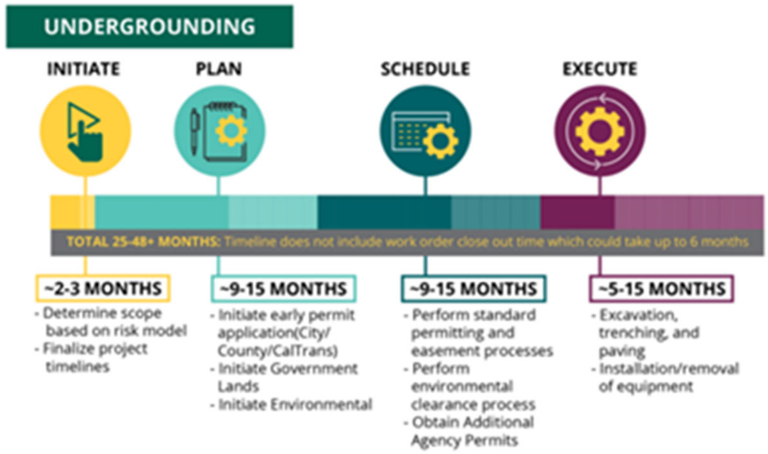
[81] This estimate does not include the time between in-field project completion to work order close-out.

undergrounding work; resources may need to address whether generation is necessary to support the existing customers on the circuit during an outage. Additional resources develop and schedule alternate traffic plans as needed based on applicable laws of the city where work is taking place. Once the project is underway, the construction team will monitor the project to ensure adherence to the design standards. Construction can be delayed due to inclement weather[82] (*e.g.*, rain/snow, Red Flag Warning (RFW) days, etc.), material delays, permit requirements, as well as environmental constraints (*e.g.*, nesting birds). Construction time can vary from 5-15 months, assuming no additional significant delays.

To complete the construction, both civil crews and Qualified Electrical Workers (QEWs) are required to perform the work. There are many additional factors that may impact the duration of the project, including permitting and environmental requirements, easements, geography and terrain, construction resource availability, and other unforeseen circumstances. The Proposed Plan considers the mitigation deployment cycle time, risk reduction, and resource constraints to pragmatically reduce risk in light of these factors.

[82] Items like this can also affect the schedule for installing covered conductor.

Figure VII-16
Timeline of Undergrounding Work



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3. Affordability

While the primary focus of our Proposed Plan is to expeditiously reduce wildfire and PSPS risk, cost is also a major consideration in SCE's decision-making process. In addition to RSEs that assess the risk reduction benefits of each initiative compared to its costs, the total cost associated with any initiative is also carefully considered.

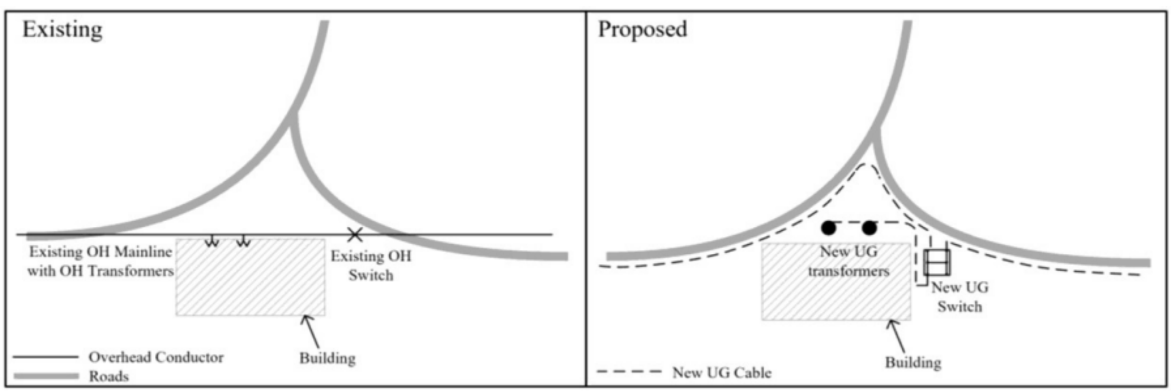
The Proposed Plan has a higher cost than Alternative Plan #1, which does not include TUG. But SCE strongly believes that the long-term benefit of *selectively* undergrounding portions of the overhead distribution system as outlined in the Proposed Plan is a more prudent path than Alternative Plan #1, for two main reasons. First, Alternative Plan #1 would not fully address the public safety risks associated with ignitions in or adjacent to areas with population egress constraints. Second, Alternative Plan #1 also would not adequately mitigate the risks associated with potential increased PSPS events.

The Proposed Plan is also superior to Alternative Plan #2, since this second alternative plan does not adequately address the absolute risk associated with a higher tolerance for simulated wildfire risk. The higher tolerance level in Alternative Plan #2 does not adequately mitigate risk in, for instance, locations that are adjacent to population centers. Historical wildfires, as well as wildfire simulations in these locations, have been demonstrated to have the potential to ultimately grow into large fires and cause urban conflagration (large fire that spreads beyond a natural or artificial barrier, *e.g.*, a city block).[83]

4. Other Considerations

Undergrounding lines often requires re-routing. This results in more circuit miles constructed than if the structures were left overhead. Figure VII-17 below illustrates why additional conductor length may be required in comparison to existing overhead configuration. The figure shows a re-routing scenario for undergrounding where it is necessary to deviate from the existing overhead alignment and follow an existing road. Re-routing occurs when there are buildings/structures, natural barriers, civil and/or utility obstructions to bypass in order to underground according to SCE's standards. Additional cable, civil work, sub-surface structures, and/or equipment may be necessary when re-routing is needed for undergrounding.

Figure VII-17
Example Showing Existing Overhead Configuration and Proposed Undergrounding Segment that Requires Additional Conductor Length



It is also important to recognize that RSEs are not and should not be the only factor used to develop a risk mitigation plan. The RSE metric does not account for certain operational realities, resource constraints, and other factors that SCE must consider in developing its plan. For example, while PSPS may appear to be an effective solution from a risk spending efficiency perspective, there are crucial regulatory and practical limits to how much PSPS can, and should, be

[83] *See* Tunnel "East Bay" Fire (1991) which ignited adjacent to populated areas in the WUI, at https://www.usfa.fema.gov/downloads/pdf/publications/tr-060.pdf.

deployed. Indeed, the Commission prescribes that PSPS should be used only "as a last resort" despite its relatively high RSE.[84]

Moreover, the Commission's Safety and Enforcement Division (SED) agreed that focusing solely on RSEs in selecting mitigations could be "suboptimal from an aggregate risk portfolio standpoint." This feedback was included in SED's evaluation of PG&E's RAMP Report.[85] SED acknowledged that "mitigations are usually selected based on the highest risk spend efficiency score unless there may be some identified resource constraints, compliance constraints, or operational constraints that may favor another candidate measure with a lower RSE."[86]

Because the very riskiest circuit segments on SCE's distribution system are in some cases hundreds of thousands of times riskier than other segments on a relative basis, mitigating those relatively few highest-risk circuit segments could incorrectly lead to a conclusion that the remaining absolute risk on the system after those mitigations were completed is acceptable. But the concept of relative risk is important for prioritizing and sequencing mitigation measures. It is not a sound method for determining the appropriate final scope of mitigation deployment. In other words, *relative risk appropriately informs a utility as to where to begin mitigation measures; but it is only absolute risk that should determine where to stop.* SCE has proposed a 300-acres consequence threshold (after the first 8 hours of simulated burn) as a proposed risk tolerance level. This risk tolerance levels represents an absolute risk consistent with our definition of "Small Fire."

The Proposed Plan is informed by SCE's current capabilities for evaluating and prioritizing mitigation measures, SCE's capabilities to predict potential driver occurrences, and the availability of technologies that can be deployed and that are effective at mitigating wildfire risk. In performing these mitigation measures over time, different factors may drive adjustments to the Proposed Plan. These factors include changes to the risk landscape that may be impacted by climate

84 As discussed elsewhere in this RAMP, SCE has not finalized an RSE for PSPS as a mitigation to ignition risk. This approach is in conformance with the Commission's guidance provided in D.21-08-036.

85 Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric Company Investigation 17-11-003, p. 18.

86 *Id*. at p. 17.

change and/or mitigation measures implemented by third parties, and improvements in SCE's ability to evaluate wildfire risk across its service area. Also, policy constraints may restrict SCE's ability to implement desired mitigations or may change how we allocate limited resources.

Lastly, as new technologies emerge, SCE will continue to evaluate the effectiveness of more advanced solutions and how they may complement its existing portfolio of mitigation measures. If new measures prove to be better than existing ones, SCE will work to transition to these improved measures as appropriate.

B. PSPS

SCE's PSPS Proposed Plan is built around continuing SCE's PSPS protocols and operating procedures, as well as ongoing customer programs, services and notifications. Despite no major changes to protocols or execution, SCE expects that the frequency and duration of proactive PSPS de-energization to decrease as wildfire mitigation work and grid hardening continues. The targeted undergrounding approach as described in our Wildfire Proposed Plan, for instance, is expected to yield higher wind-speed thresholds which, in turn, would reduce the need to proactively de-energize those circuits (assuming steady state weather and fuel conditions).

The elements of this Proposed Plan are shown in Table VII-16 below. The pre- and post-mitigation LoRE, CoRE and risk scores for the Proposed Plan are summarized by tranche below in Table VII-17.

Table VII-16
Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)

2022 RAMP ID	2022 RAMP Control Name	Total Cost Estimate ($000s) (2025 - 2028)	2025 Risk Spend Efficiency - All HFRA
C22	Weather Stations	$ 1,152	169
C23	CRC/CCV	$ 6,143	0.1
C24	CCBB	$ 26,146	0.4
C25	Customer Resiliency Equipment Rebates	$ 3,761	0.3
C26	211 Partnerships	$ 3,710	10
C27	Weather and Fuel Modeling	$ 8,116	47
C28	Fire Science	$ 12,257	19
Total		$ 61,285	

Table VII-17
Pre- and Post- LoRE, CoRE and Risk Scores

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
PSPS	24.0	0.0068	0.16	24.0	0.0068	0.16

1. Overview

SCE activates PSPS largely based on two factors. The first factor used to drive PSPS decisions is the FPI, which estimates the likelihood of a spark turning into a major wildfire. FPI is calculated using forecast wind speed, dewpoint depression, and various fuel moisture variables which are generated from SCE's customized version of the Weather Research and Forecasting (WRF) model. As described in the FPI section earlier in the document, SCE's FPI scores range from 1 to 17. Any score at or above 12-13 (based on, for example, fire climate zone) is considered high risk. SCE reviews fire potential-related products from the National Weather Service (NWS) and the

Geographic Area Coordination Center (GACC) to confirm the wildfire threat in its PSPS decision-making process.

The second factor used to drive PSPS decisions is wind speed. SCE considers the NWS Wind Advisory levels (defined as 31 mph sustained wind speed and 46 mph gust wind speed) and the 99th percentile of historical wind speeds in the area to set activation thresholds. The Wind Advisory level is chosen because of the propensity for debris or vegetation to become airborne. A circuit's 99th percentile wind speeds represents rare or extreme wind speeds that a particular circuit experiences approximately four times per year. The de-energization threshold for isolatable segments with covered conductor is 40 mph sustained wind and 58 mph gusts. This aligns with the NWS high wind warning level for windspeeds at which infrastructure damage may occur.[87]

If actual fire weather conditions necessitate PSPS de-energization, SCE has an existing suite of customer offerings to mitigate the impacts of PSPS. These efforts include:

- Deployment of free portable batteries to Medical Baseline (MBL) customers in HFRA;
- Expanded outreach, community resiliency, customer rebate offerings; launching of new AFN IMT role, AFN webpage, and the 2-1-1 program to respond to customer needs during PSPS events;
- Improved availability of emergency information through a new Public Safety Partners Portal and enhancements to customer notifications during PSPS; and
- Automated IT solutions to improve efficiency during IMT activations, including end-to-end process integration for customer notifications.

SCE contracts with dozens of indoor CRC locations and maintains mobile CCVs. To support customers in remote communities, SCE reached out to select customers to install transfer switches that enable back-up power connection during a PSPS event. These locations are essential

87 If actual conditions suggest more risk, or in large-scale events when many circuits are under consideration for shutoff, the de-energization thresholds may be lowered (discounted). This means that power on a circuit will be turned off at lower wind speeds.

service sites such as gas stations and mini-mart grocery stores. SCE will deploy a backup generator to these locations during a PSPS event if necessary.

SCE utilizes several communication channels for its customers, Public Safety Partners, and other stakeholders regarding PSPS, including: 1) PSPS event notifications to SCE customers, including Critical Infrastructure customers and Public Safety Partners; 2) notifications to local jurisdictions, Local City/County/Tribal Officials, CAL FIRE, Cal OES, CCA Administrators, State and Federal Legislative District Offices, 2-1-1 Operators, Independent Living Centers, and other stakeholders with longer-range emergency planning responsibilities; 3) posting on the Public Safety Partner Portal for emergency providers and Critical Infrastructure customers; and 4) SCE.com, social media outreach, and address-level alerts available to non-SCE-account holders for any address that could be impacted by PSPS. In addition, SCE engages in a suite of outreach activities, including community meetings, marketing campaigns and customer research and education.

SCE provides PSPS event notifications pursuant to the guidelines provided by the Commission, as shown in the table below. SCE understands its stakeholders have different needs and require varying methods of alerts and notifications. For example, first responders, Public Safety Partners, and local governments require as much lead time as practical to begin contacting constituents and preparing to respond to potential de-energizations. To support this need, SCE provides priority notification to these agencies between 48 to 72 hours before a potential PSPS de-energization, if weather conditions can be predicted this far in advance. This information is also posted to sce.com at the 72-hour mark when possible.

Additional alerts and warning update notifications are then made at 24-hour intervals with these agencies to maintain operational coordination. SCE sends initial alerts and warning messages to remaining customers up to 48 hours in advance of a potential PSPS event via the customers' preferred method of communication (*e.g.*, text, e-mail, voice call, and TTY). Notifications are then made to these customers at 24-hour intervals if there is updated information regarding the ongoing potential PSPS event. Notifications are offered in multiple languages, as described in Section 8.4, below.

Table VII-18
De-Energization Notification Requirements

Stakeholder	Initial Notification (Alert)	Update Notification (Alert)	Imminent Shut Down (Warning)*	De- Energized (Statement)	Preparing for Re-Energization (Statement) **	Re-Energized (Statement)	PSPS Averted (Statement)
First/ Emergency Responders/ Public Safety Partners, local governments, and tribal governments	72 hours before	48 & 24 hours before	1 – 4 hours before	When De-Energization is Authorized	When weather threat has receded, and patrol and inspection is authorized	When Re-Energization Occurs	When circuits are no longer being considered for PSPS
Critical Infrastructure Providers	72 hours before	48 & 24 hours before	1 – 4 hours before	When De-Energization is Authorized	When weather threat has receded, and patrol and inspection is authorized	When Re-Energization Occurs	When circuits are no longer being considered for PSPS
Customers	48 hours before	24 hours before	1 – 4 hours before	When De-Energization is Authorized	When weather threat has receded, and patrol and inspection is authorized	When Re-Energization Occurs	When circuits are no longer being considered for PSPS

SCE will target the schedule above to notify customers. Erratic or sudden onset of hazardous conditions that jeopardize public safety may impact SCE's ability to provide advanced notice to customers.
*SCE will make every attempt to notify customers of imminent de-energization at the 1- to 4-hour warning stage. Given the unpredictability of shifting weather during PSPS, implementation of this imminent notification timeframe may vary.
**SCE will attempt to notify customers before re-energization when possible

2. <u>Execution Feasibility</u>

SCE possesses several years of experience in successfully maintaining and operating a dedicated PSPS organization. While SCE will continue to improve the program and protocols where possible, the core work remains the same. That central work will be carried out by a trained, dedicated PSPS IMT team staffed solely for the purpose of responding to PSPS events. This dedicated team fosters greater consistency before, during, and after PSPS activations, especially when communicating with customers and Public Safety Partners. The ICS structure used by SCE is the same as those typically utilized by private and public organizations across the country. It is considered a best practice for emergency response, regardless of incident size or type. ICS has been successfully utilized at SCE for several years, allowing for the IMT to respond in a cohesive, integrated manner during any activation, including those related to wildfires and PSPS events. Additionally, SCE maintains a comprehensive annual training and exercise routine to ensure continuous improvement. This program closely adheres to State and Federal emergency management guidance for readiness standards.

3. Affordability

The costs associated with SCE's PSPS Proposed Plan are relatively modest in comparison to other wildfire mitigation activities and programs. SCE acknowledges and is sensitive to the costs and burdens that PSPS events impose on our customers.

4. Other Considerations

SCE will continue to assess and refine its FPI and wind-speed thresholds to more directly account for how wind impacts the outage behavior of circuits subject to PSPS events.

VIII.

ALTERNATIVE PLANS

A. Wildfire Alternative Plan #1

1. Overview

SCE utilized the decision tree in Figure VIII-18 below to determine Wildfire Alternative Plan #1. Under this plan, SCE would not install targeted undergrounding as a mitigation in the 2025-2028 period. This means SCE would instead implement the full CC++ suite as the primary mitigation for both Severe Risk Areas and High Consequence Segments. Given there are circuits which may exceed de-energization criteria even when fully covered by covered conductor, under Alternative Plan #1 SCE may need to resort to PSPS more often than in SCE's Proposed Plan.

Alternative Plan #1 included identifying locations for the installation of microgrids that can island from the grid during de-energization events and provide backup power to customers to help mitigate the impact of PSPS. Table VIII-19 and Table VIII-20 show the 2025-2028 alternative scopes and associated costs and risk mitigated by the end of 2028. For the remaining mitigation activities in Alternative Plan #1, SCE proposes to deploy many of the same controls and mitigations as are found in the Proposed Plan. Activities that differ from the Proposed Plan are indicated in orange highlights. Ultimately, this plan would not reduce as much wildfire or PSPS risk compared to executing the Proposed Plan. Further, microgrids have not proven to be easily scaled and deployed in SCE's HFRA to date.

Figure VIII-18
Integrated Grid Hardening Strategy: WF Alternative Plan #1
(No Targeted Undergrounding)

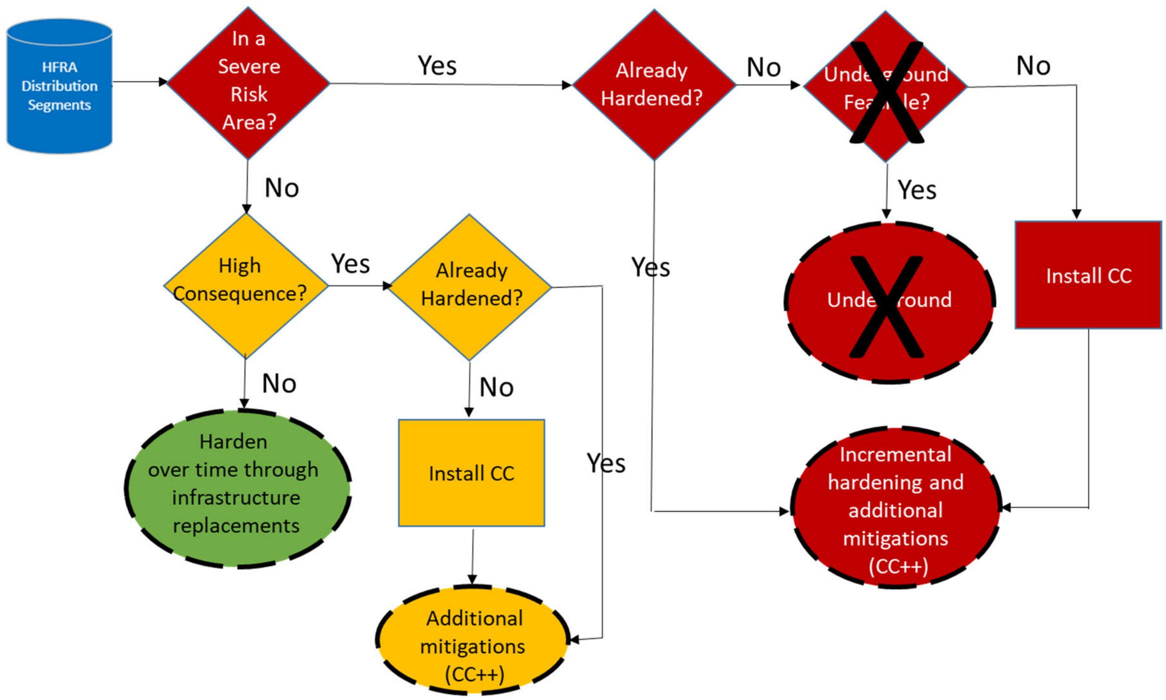


Table VIII-19
Wildfire Alternative Plan #1 Activities 2025-2028 (Units)

2022 RAMP ID	2022 RAMP Control Name	Type	2025	2026	2027	2028	Total 2025-2028
C1	WCCP	circuit miles	910	450	250	220	1,830
C1a	FR Poles	structures	10,647	5,265	2,925	2,574	21,411
C2	Branch Line (Fuses)	circuit miles	45	45	45	45	180
C3	RAR/RCS	circuit miles	282	282	282	282	1,128
C6	Tree Attachment Remediation	structures	800				800
C7	Microgrids	locations	2	2	2	2	9
C8	Long Span Initiative	structures	7,068				7,068
C10	Distribution Ground	structures	12,460	11,990	12,460	12,460	49,371
C11	Distribution Aerial	structures	4,609	4,435	4,609	4,609	18,261
C12	Transmission Ground	structures	1,593	2,588	2,588	2,588	9,356
C13	Transmission Aerial	structures	503	817	817	817	2,955
C14	Distribution Infrared	structures	28	28	28	28	112
C15	Transmission Infrared	structures	2	2	2	2	8
C16	Hazard Tree Mitigation Program	structures	14,850	14,850	14,850	14,850	59,400
C17	Expanded Pole Brushing	structures	119,900	119,900	119,900	119,900	479,600
C18	Dead and Dying Tree Removal Progra	structures	12,442	14,930	17,916	21,499	66,787
C19	Expanded Line Clearing	structures	166,714	166,714	166,714	166,714	666,856
C21	Aerial Suppression		9,689	9,689	9,689	9,689	38,757
M1	Targeted Undergrounding	circuit miles	0	0	0	0	0
M2	REFCL (Total)	circuit miles	1,100	1,100	350	350	2,900
M3	Vibration Damper	circuit miles	31	31	0	0	63
M4	DOPD	circuit miles	228	228	228	228	912
M5	EFD	circuit miles	810	811	810	810	3,241
M6	Hi-Z	circuit miles	296	296	297	296	1,186

Table VIII-20
Alternative Plan #1 (Total Costs Nominal $000's and 2025 Risk Spend Efficiencies)

2022 RAMP ID	2022 RAMP Control Name	Total Cost Estimate ($000s) (2025 - 2028)	2025 Risk Spend Efficiencies T1 - Severe Risk Areas	T2 - High Consequence Segments	T3 - Other HFRA
C1	WCCP	$ 1,109,664	1,562	1,947	618
C1a	FR Poles	$ 72,446	60	52	32
C2	Branch Line (Fuses)	$ 6,074	4,009	3,524	3,812
C3	RAR	$ 15,832	4,200	7,135	2,915
C6	Tree Attachment Remediation	$ 27,479	6,706	6,525	4,948
C7	Microgrids	$ 46,400	1	-	-
C8	Long Span Initiative	$ 30,052	1,523	1,670	1,504
C10	Distribution Ground	$ 385,346	246	246	229
C11	Distribution Aerial	$ 159,171	70	69	65
C12	Transmission Ground	$ 95,844	-	602	567
C13	Transmission Aerial	$ 66,909	-	214	214
C14	Distribution Infrared	$ 1,843	1	1	1
C15	Transmission Infrared	$ 991	-	0	-
C16	Hazard Tree Mitigation Program	$ 193,007	19	19	19
C17	Expanded Pole Brushing	$ 31,617	3,202	2,282	1,012
C18	Dead and Dying Tree Removal Program	$ 200,033	23	22	22
C19	Expanded Line Clearing	$ 187,317	469	305	148
C21	Aerial Suppression	$ 73,934	4,120	2,825	787
M1	Targeted Undergrounding	$ -	-	-	-
M2	REFCL (Total)	$ 204,688	26,186	25,355	21,998
M3	Vibration Damper	$ 3,464	146	145	28
M4	DOPD	$ 6,785	7,382	5,720	3,018
M5	EFD	$ 51,081	1,917	3,140	716
M6	Hi-Z	$ 5,428	4,623	3,438	2,083
Total		$ 2,975,406			

The pre- and post-mitigation LoRE, CoRE and risk scores for Alternative Plan #1 are summarized by tranche below in Table VIII-21.

Table VIII-21
Pre- and Post- LoRE, CoRE and Risk Scores

	Pre-Mitigation Risk Quantification Scores (End of 2024)			**Post-Mitigation Risk Quantification Scores (End of 2028)**		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Wildfire - All HFRA	32.5	1.5	47.6	26.8	1.5	41.5
T1 - Severe Risk Areas	4.3	3.6	15.4	4.1	3.7	15.3
T2 - High Consequence Segments	13.5	2.2	29.3	10.2	2.3	23.8
T3 - Other HFRA	14.8	0.2	2.9	12.4	0.2	2.3

2. <u>Execution Feasibility</u>

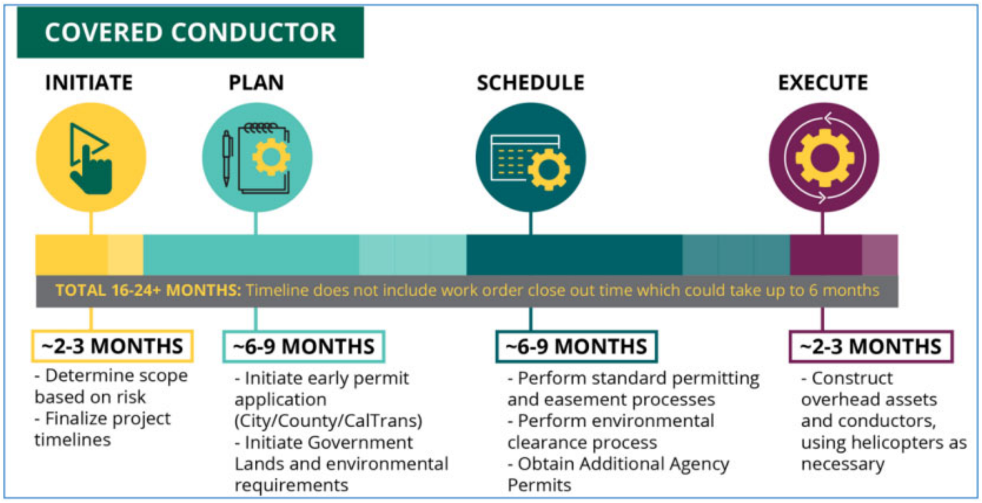
Alternative Plan #1 proposes an additional 580 covered conductor miles compared to the Proposed Plan. Covered conductor deployment has an estimated timeframe of 16 to 24+ months from initial scoping to in-field project completion (see Figure VIII-19 below).[88] Once the project is ready to start, construction will proceed with necessary environmental monitoring if required during the Execute Phase. Please refer to Figure VIII-19 below for an explanation of the Execute Phase, as well as the subsequent designated Phases in our work timeline. There are many factors that may affect the construction timeline, including the size of the project, location of the project, terrain, environmental restrictions, weather (*e.g.*, rain/snow, RFW days, etc.), resource availability, and adherence to city or local requirements. Every project will have unique factors that impact project timelines.

QEWs are required to perform the electrical construction work. SCE uses a combination of SCE workers and external contractor crews to perform this work. The selection of which resource to utilize is based on crew availability, work priorities, location, and other factors. Because there are numerous factors that can impact the Execute Phase, the average timeline in the figure below includes 2-3 months for the execution phase that assumes relatively good conditions, *e.g.*, minimal agency requirements, no environmental restrictions, no RFW days, etc. Under challenging conditions, such as

[88] This estimate does not include the time between in-field project completion to work order close-out.

access issues, difficult terrain, environmental constraints, or significant agency requirements, the execution phase can take up to 6-12 months.

Figure VIII-19
Timeline of Covered Conductor Work



While SCE has experience in execution and a greater understanding of installation cycle times of the covered conductor program, SCE is gradually advancing our experience with microgrids. We have experienced delays in deploying our current microgrid pilots. SCE did not include microgrids in its Proposed Plan due to several challenges with its pilot projects and in light of the limited number of customers who can benefit from microgrids.

For example, a pilot project was started in 2021 to implement a microgrid control system for a school in the Rialto Unified School District that will support PSPS events as a Community Resource Center. The ongoing global supply chain issues delayed the delivery of the materials (energy storage components, Automatic Transfer switch, etc.) required to complete the Rialto school site. Additionally, SCE identified circuits for siting of a microgrid to mitigate PSPS events and selected a circuit that experienced 72 hours of PSPS outages in 2021. Although initial evaluation identified multiple viable land plots, SCE has been unable to secure land to locate Distributed Energy Resources. This project is currently on hold pending the land acquisition. While SCE is committed to further exploring microgrids as a viable alternative, at this point we are not in a position to propose this level of microgrid deployment due to the referenced challenges.

3. Affordability

Alternative Plan #1 is a lower-cost plan from a utility-funding perspective than our Proposed Plan, because under this Alternative Plan, SCE would deploy covered conductor and other mitigations in locations where SCE would be deploying TUG in the Proposed Plan. Covered conductor has lower costs than undergrounding and can be deployed much faster.

However, Alternative Plan #1 would not reduce as much absolute risk as the Proposed Plan, since undergrounding almost completely addresses ignition risk drivers associated with overhead conductor failure and is uniquely beneficial for areas with egress and PSPS risks. While deploying covered conductor may significantly increase the windspeed threshold for de-energization during a risk event, it does not completely prevent those de-energizations during extreme wind events. In contrast, undergrounding can essentially eliminate the need for de-energizations under the same circumstances.[89] Performing undergrounding as projected in the Proposed Plan would yield a much-improved customer experience through virtually eliminating the use of PSPS in those undergrounded locations.

In addition, because of the lesser ignition risk reduction, there may be a greater likelihood that one or more significant fire events occur during the RAMP period under Alternative Plan #1 as compared to the Proposed Plan. As SCE has repeatedly stated, it is the costs of wildfires themselves that are unaffordable for customers, not the costs incurred for the mitigations to prevent them.

4. Other Considerations

SCE has not identified any other considerations that are not discussed above.

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[89] Note that if the undergrounded circuit is connected to another portion of the circuit that experiences PSPS, the undergrounded portion would still be de-energized.

B. Wildfire Alternative Plan #2

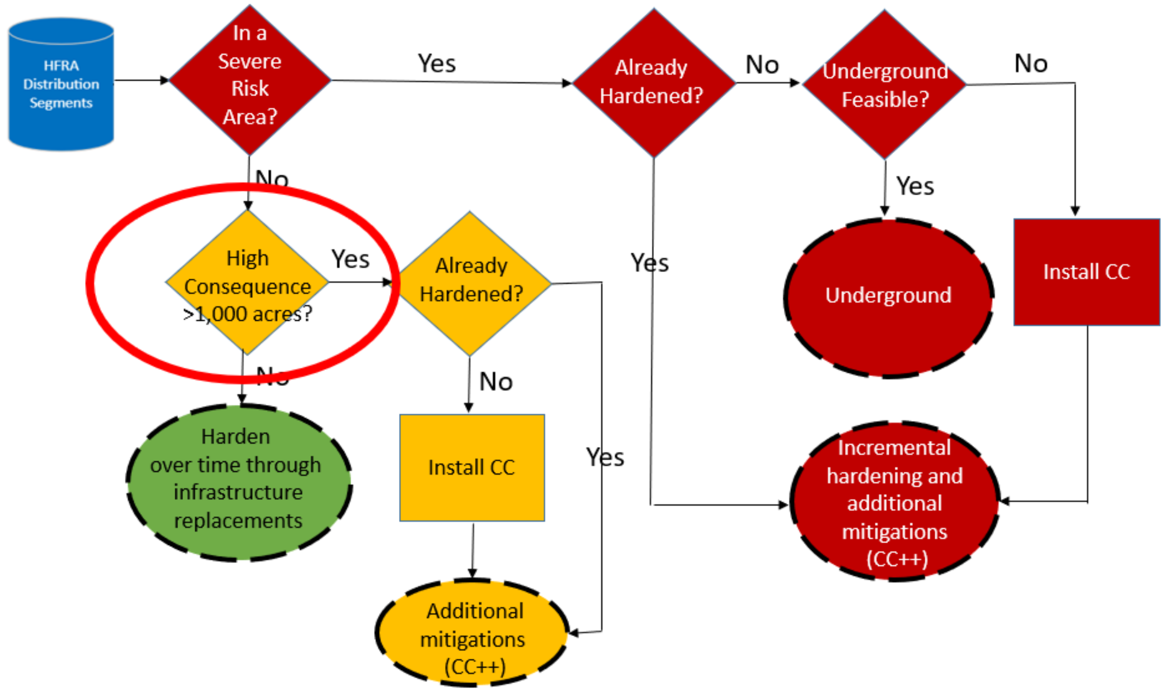
1. Overview

Similar to the process used to develop our Proposal Plan and Wildfire Alternative Plan #1, SCE utilized our Integrated Grid Hardening Strategy decision tree to derive Alternative Plan #2 (see Figure VIII-20 below). In contrast to our Proposed Plan, where the High Consequence threshold was set at 300 acres burned (after 8 hours), in Alternative Plan #2 SCE increases the risk threshold to 1,000 acres burned (after 8 hours). This plan would result in SCE not deploying any additional covered conductor work in High Consequence Segments during the 2025-2028 period. Table VIII-22 and Table VIII-23 show the 2025-2028 scope for Alternative Plan #2, and associated costs and risk mitigated by the end of 2028.

With the exception of the scope of covered conductor deployment, Alternative Plan #2 deploys many of the same controls and mitigations as the Proposed Plan.

While Alternative Plan #2 is a lower-cost plan compared to the Proposed Plan from a utility-spending perspective, it provides markedly less mitigation of the significant wildfire risks, particularly in the Wildfire Urban Interface (WUI). Additionally, this plan does not drive down the need for continued PSPS activation in areas of the system that are not undergrounded; this can be a particular vulnerability where circuits cross the boundaries of both High Consequence Segments and Other HFRA.

Figure VIII-20
Integrated Grid Hardening Strategy: WF Alternative Plan #2
(Increase High Consequence Threshold to 1,000 acres burned after 8 hours)



*Because of the uncertainties associated with accelerating climate change and changing risk profiles, in certain cases, SCE may need to underground specific circuit segments that were already hardened with covered conductor to further reduce risk and protect SCE's customers. At this time, SCE expects such occurrences to be the exception and not the rule.

Table VIII-22
Wildfire Alternative Plan #2 Activities 2025-2028 (Units)

2022 RAMP ID	2022 RAMP Control Name	Type	2025	2026	2027	2028	Total 2025-2028
C1	WCCP	circuit miles	0	0	0	0	0
C1a	FR Poles	structures	0	0	0	0	0
C2	Branch Line (Fuses)	circuit miles	45	45	45	45	180
C3	RAR/RCS	circuit miles	282	282	282	282	1,128
C6	Tree Attachment Remediation	structures	800				800
C8	Long Span Initiative	structures	7,068				7,068
C10	Distribution Ground	structures	12,460	11,990	12,460	12,460	49,371
C11	Distribution Aerial	structures	4,609	4,435	4,609	4,609	18,261
C12	Transmission Ground	structures	1,593	2,588	2,588	2,588	9,356
C13	Transmission Aerial	structures	503	817	817	817	2,955
C14	Distribution Infrared	structures	28	28	28	28	112
C15	Transmission Infrared	structures	2	2	2	2	8
C16	Hazard Tree Mitigation Program	structures	14,850	14,850	14,850	14,850	59,400
C17	Expanded Pole Brushing	structures	119,900	119,900	119,900	119,900	479,600
C18	Dead and Dying Tree Removal Program	structures	12,442	14,930	17,916	21,499	66,787
C19	Expanded Line Clearing	structures	166,714	166,714	166,714	166,714	666,856
C21	Aerial Suppression		9,689	9,689	9,689	9,689	38,757
M1	Targeted Undergrounding	circuit miles	65	180	240	200	685
M2	REFCL (Total)	circuit miles	1,100	1,100	350	350	2,900
M3	Vibration Damper	circuit miles	31	31	0	0	63
M4	DOPD	circuit miles	228	228	228	228	912
M5	EFD	circuit miles	810	811	810	810	3,241
M6	Hi-Z	circuit miles	296	296	297	296	1,186

Table VIII-23
Alternative Plan #2 (Total Costs Nominal $000s and 2025 Risk Spend Efficiencies)

			2025 Risk Spend Efficiencies		
2022 RAMP ID	**2022 RAMP Control Name**	**Total Cost Estimate ($000s) (2025 - 2028)**	**T1 - Severe Risk Areas**	**T2 - High Consequence Segments**	**T3 - Other HFRA**
C1	WCCP	$ -	-	-	-
C1a	FR Poles	$ -	-	-	-
C2	Branch Line (Fuses)	$ 6,074	4,477	3,231	4,710
C3	RAR	$ 15,832	4,184	4,184	4,184
C6	Tree Attachment Remediation	$ 27,479	7,105	7,250	5,793
C8	Long Span Initiative	$ 30,052	1,729	1,937	1,680
C10	Distribution Ground	$ 385,346	261	262	246
C11	Distribution Aerial	$ 159,171	74	71	69
C12	Transmission Ground	$ 95,844	-	600	565
C13	Transmission Aerial	$ 66,909	-	214	214
C14	Distribution Infrared	$ 1,843	1	0.84	0.71
C15	Transmission Infrared	$ 991	-	0.00	0.00
C16	Hazard Tree Mitigation Program	$ 193,007	20	20	20
C17	Expanded Pole Brushing	$ 31,617	3,259	2,479	1,012
C18	Dead and Dying Tree Removal Program	$ 200,033	23	23	23
C19	Expanded Line Clearing	$ 187,317	477	326	148
C21	Aerial Suppression	$ 73,934	4,200	3,106	800
M1	Targeted Undergrounding	$ 3,098,420	452	-	-
M2	REFCL (Total)	$ 204,688	27,965	28,738	26,970
M3	Vibration Damper	$ 3,464	-	-	-
M4	DOPD	$ 6,785	7,382	5,938	3,032
M5	EFD	$ 51,081	1,949	3,377	780
M6	Hi-Z	$ 5,428	4,733	4,013	2,084
Total		$ 4,845,317			

The pre- and post-mitigation LoRE, CoRE and risk scores for Alternative Plan #2 are summarized by tranche below in Table VIII-24.

Table VIII-24
Pre- and Post- LoRE, CoRE and Risk Scores

	Pre-Mitigation Risk Quantification Scores (End of 2024)			**Post-Mitigation Risk Quantification Scores (End of 2028)**		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Wildfire - All HFRA	33.9	1.5	50.4	31.9	1.5	46.7
T1 - Severe Risk Areas	4.4	3.6	15.8	2.8	4.4	12.5
T2 - High Consequence Segments	14.5	2.2	31.7	14.0	2.2	31.3
T3 - Other HFRA	15.0	0.2	2.9	15.0	0.2	2.9

2. **Execution Feasibility**

SCE believes Alternative Plan #2 is executable. Under this alternative, SCE's grid hardening resources would be fully dedicated to TUG, as no covered conductor would be installed during the RAMP period.

3. **Affordability**

Alternative Plan #2 is a lower-cost alternative from a utility-investment perspective compared to the Proposed Plan, because SCE would not be deploying covered conductor in locations that would be covered under the Proposed Plan. But this would result in approximately 1,250 circuit miles in the High Consequence Segments[90] area remaining unhardened and exposed.

Bare conductor is more prone to faults associated with contact from object, which may lead to ignitions associated with SCE equipment. Additionally, bare conductor has a much lower de-energization threshold than covered conductor.[91] In other words, customers would be subject to more PSPS events, because power on a circuit would be turned off at lower windspeeds compared to the thresholds that can be accommodated when covered conductor is present.

As discussed above, although Alternative Plan #2 would be a lower-cost path from a utility-spend perspective in the short term, it would not reduce as much risk as the Proposed Plan. In addition, because of that lesser amount of ignition risk reduction, there would be a greater likelihood of one or more significant fire events occurring during the RAMP period as compared to the Proposed Plan. As SCE has repeatedly stated, it is the costs of wildfires themselves that are unaffordable for customers, not the costs for the mitigations to prevent them.

4. **Other Considerations**

SCE has not identified any other considerations that are not discussed above.

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[90] The 1,250 miles may include miles in "Other HFRA" to account for operational realities.

[91] The de-energization threshold for unhardened segments is typically set around 31 mph sustained winds or 46 mph gusts, whereas for covered conductor it is 40 mph sustained/58 mph gusts.

C. PSPS Alternative Plan #1

SCE's Alternative Plan #1 would seek to limit customer impacts due to PSPS through a shift in increasing risk tolerance, and a subsequent lessening of the need to resort to PSPS de-energization.

1. Overview

One way to reduce customer impacts would be to lessen the frequency of PSPS de-energizations themselves. Were SCE to increase its FPI thresholds to a value of 15 (or extreme fire potential) in all of its Fire Climate Zones (FCZs), PSPS events would likely be all but eliminated based on average exceedance over this higher level over the past decade (as opposed to the 314 circuit hours forecast in Section II.D.2). As of the filing this RAMP, SCE's FPI thresholds are set based on historical FPI and fire data, resulting in a 12 threshold for all circuits in FCZ 1 and a 13 for all circuits in the remaining FCZs.

The elements of this Alternative Plan are shown in Table VIII-25 below. The pre- and post-mitigation LoRE, CoRE and risk scores for the Alternative Plan are summarized by tranche below in Table VIII-26.

Table VIII-25
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)

2022 RAMP ID	2022 RAMP Control Name	Total Cost Estimate ($000s) (2025 - 2028)	2025 Risk Spend Efficiency - All HFRA
C22	Weather Stations	$ 1,152	7.0
C23	CRC/CCV	$ 6,143	0.00
C24	CCBB	$ 26,146	0.02
C25	Customer Resiliency Equipment Rebates	$ 3,761	0.01
C26	211 Partnerships	$ 3,710	0.4
C27	Weather and Fuel Modeling	$ 8,116	2.0
C28	Fire Science	$ 12,257	0.8
Total		$ 61,285	

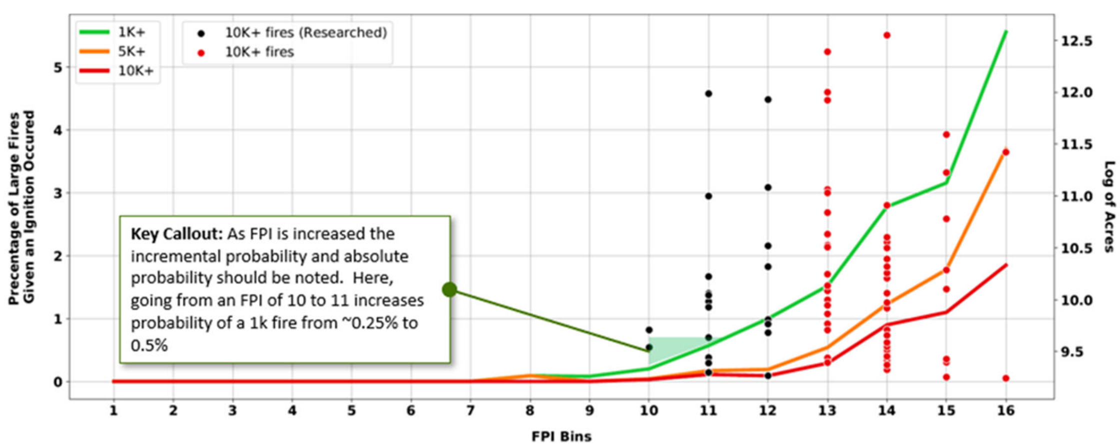
Table VIII-26
Pre- and Post- LoRE, CoRE and Risk Scores

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
PSPS	24.0	0.0068	0.16	1.0	0.0068	0.007

2. Execution Feasibility

Driving down PSPS frequency would likely have an inverse relationship with ignition risk. Figure VIII-21 below shows the potential for large fires to propagate, should an ignition occur. SCE has been measured in calibrating the FPI scale to its service area and will continue to analyze fire and weather outcomes to identify areas for improvement. At the time of this filing, an FPI threshold increase is not recommended, since it would expose customers to increased wildfire risk.

Figure VIII-21
Correlation of Actual FPI Thresholds to Fire Consequences



3. Affordability

While likely allowing for a small decrease in PSPS execution costs due to fewer line patrols and less IMT activity, this alternative would substantially increase the risk of large, damaging wildfires. Any potential operating cost savings and other benefits to customers through deploying

Alternative Plan #1 would likely be more than offset by costs and impacts to the customers from the greater wildfire risk.

4. Other Considerations

SCE has not identified any other considerations that are not discussed above.

D. PSPS Alternative Plan # 2

SCE's second alternative plan does not propose changes to PSPS risk tolerance or frequency from the Proposed Plan. Instead, under Alternative Plan #2 customer impacts from PSPS events would be reduced by increasing the goods and services provided to customers during those events and increasing the scope of pre-event notifications.

1. Overview

SCE's outcomes for de-energized customers differ based on whether they were notified of de-energization prior to the event occurring or not. This is because customers who have advance notice have more time to take steps to prepare for the event. Accordingly, SCE's first action as part of this Alternative Plan would be to notify customers on a broader basis than is currently performed (*e.g.*, at substation level), should any circuit in that area be forecast to exceed PSPS thresholds. This more conservative posture would cast a wider net for PSPS notifications, meaning that customers would be far less likely to be de-energized without notification, should weather changes pull unforeseen circuits into scope for PSPS de-energization. It would also mean that many more customers would receive a notification but would not be de-energized.

Second, this proposal would increase goods and services provided by SCE's CRCs and CCVs and customer resiliency programs for batteries and generators. Additionally, SCE would increase its marketing budget to encourage customers to take advantage of these programs.

The elements of this Alternative Plan #2 are shown in Table VIII-27 below. The pre- and post- mitigation LoRE, CoRE and risk scores for the Alternative Plan # 2 are summarized by tranche below in Table VIII-28.

Table VIII-27
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)

2022 RAMP ID	2022 RAMP Control Name	Total Cost Estimate ($000s) (2025 - 2028)	2025 Risk Spend Efficiency - All HFRA
C22	Weather Stations	$ 16,618	168
C23	CRC/CCV	$ 8,144	0.1
C24	CCBB	$ 26,146	0.4
C25	Customer Resiliency Equipment Rebates	$ 5,840	0.4
C26	211 Partnerships	$ 3,710	10
C27	Weather and Fuel Modeling	$ 8,116	48
C28	Fire Science	$ 2,962	19
Total		$ 71,782	

Table VIII-28
Pre- and Post- LoRE, CoRE, and Risk Scores

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
PSPS	24.0	0.0068	0.16	24.0	0.0068	0.16

2. <u>Execution Feasibility</u>

SCE could execute this alternative plan, but SCE does not currently employ a broad notification strategy. We have concerns regarding over-notification and customer fatigue due to "false positive" notifications. Previous Commission guidance has emphasized the need to reduce false positive notifications, and only alert those customers who are likely to be de-energized.

With regard to customer programs, SCE has developed its current offerings by carefully analyzing customer feedback and participation. Increasing the offerings to customers would be achievable but is not guaranteed to make the additional costs worthwhile.

3. Affordability

RSEs for this alternative plan are slightly lower overall, because increasing costs in this area would not yield a proportional benefit for customers on the whole.

4. Other Considerations

SCE has not identified any other considerations that are not discussed above.

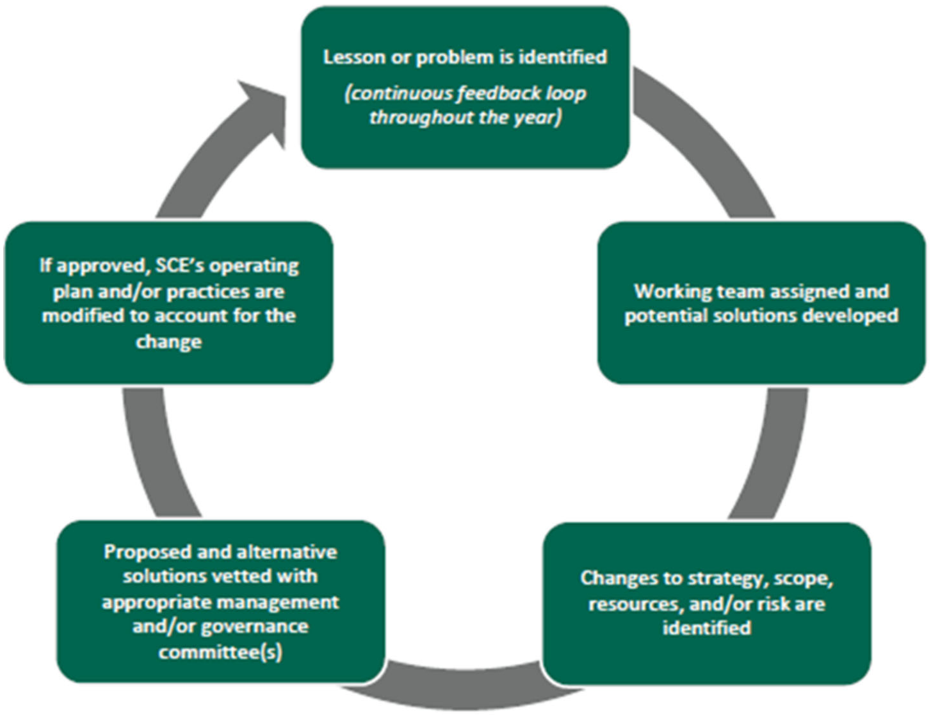
IX.

LESSONS LEARNED, DATA COLLECTION, AND PERFORMANCE METRICS

A. Lessons Learned, Data Collection and Availability

SCE's wildfire mitigation efforts have continued to advance to mitigate the threat of wildfires in HFRA. SCE regularly re-evaluates its wildfire mitigation initiatives based on execution experience, internal analysis, stakeholder feedback, benchmarking, customer surveys, and post-event PSPS reports. At a high level, SCE leverages a general lesson learned process as depicted in Figure IX-22 below. This process is used as warranted. Above, SCE explains in detail the progress we have made in our risk modeling. Please refer to section II.A.1.

Figure IX-22
SCE's General Lessons Learned Process



SCE has also made advances in the following areas: Resource Allocation, Risk Assessment and Mapping, Situational Awareness, Grid Design and System Hardening, Asset Management and Inspections, Vegetation Management and Inspections, Grid Operations and Protocols and Data Governance. A detailed description of these advancements can be found in Chapter 4 of SCE's 2020-2022 WMP, as well as the 2021 and 2022 Annual Updates to the WMP.

B. <u>Performance Metrics</u>

As part of SCE's annual Wildfire Mitigation Plans (WMP) and quarterly updates, SCE provides metrics information in our annual Safety Performance Metrics Report (SPMR). Below in Table IX-29 SCE highlights some of the metrics associated with the Wildfire and PSPS risks.

This should not be considered an exhaustive list. For additional metrics related to Wildfire and PSPS risks, please see SCE's WMPs and SPMR.[92]

Table IX-29
Key Wildfire and PSPS Metrics

Metric Name	Metric Definition	Purpose
CPUC reportable ignitions in High Fire Risk Areas (HFRA)	Events meeting reportable ignition status per Decision 14-02-015 and falling within BL322, HFTD Zone 1 HFTD Tier 2 and 200 ft. Outer Buffer, and HFTD Tier 3 and 200 ft. Outer Buffer areas.	To measure changes in rate of ignitions between years
Faults in HFRA	Events in which electrical current deviates from the anticipated path via SCE facilities within BL322, HFTD Zone 1 HFTD Tier 2 and 200 ft. Outer Buffer, and HFTD Tier 3 and 200 ft. Outer Buffer areas.	To measure changes in rate of fault events which are a pre-cursor to both ignition and safety events
Wire Down Incidents in HFRA	Events in which SCE overhead conductors (energized or de-energized) fall within 8ft above ground or lower, within BL322, HFTD Tier 2 and 200 ft. Outer Buffer, and HFTD Tier 3 and 200 ft. Outer Buffer areas.	To measure changes in rate of wire down events which are a pre-cursor both ignition and safety events
Number of customers and average duration of Public Safety Power Shutoff (PSPS) events		
Total # of customers de-energized	Count of customers de-energized, with duplicates, per year	To measure the scale of impact of outages due to PSPS to customers, with duplicates
Average duration of de-energization across all customers.	Average outage duration (hours per customer) experienced by PSPS de-energization per customer de-energized	Of the customers de-energized due to PSPS, to measure the magnitude of the effect of the PSPS de-energization
Timeliness and accuracy of PSPS notifications		
% of customers notified prior to a PSPS event impacting them	# of customers notified prior to initiation of PSPS event who were impacted by PSPS/ # of customers impacted by PSPS (if multiple PSPS events impact the same customer, count each event as a separate customer)	To measure success rate of notification for the customers who were impacted by de-energization
% of customers notified prior to a PSPS event that did not impact them	% of customers notified of potential de-energization that were not de-energized for that PSPS event (on a total customer basis)	To measure the occurrence of PSPS notifications and de-energizations

X.
ADDRESSING PARTY FEEDBACK

Through various regulatory proceedings including the Grid Safety and Resiliency Program (GSRP), SCE's 2020 - 2022 WMPs, SCE's 2018 RAMP, SCE's TY 2021 GRC, the Risk OIR[93] and SCE's 2022 pre-RAMP workshop, SCE has received extensive feedback from parties on Wildfire and PSPS risk modeling. In section II.A.1.above, SCE explains in detail the progress we have made in our

[92] Tables 1 – 12 in SCE's annual WMP filings contain a significant amount of metric information related to Wildfire and PSPS risks.

[93] R.20-07-013.

risk modeling that has taken parties feedback into consideration. Below SCE discusses certain feedback from our 2018 RAMP and 2022 pre-filing RAMP workshop. SCE appreciates the continuing dialogue with stakeholders on wildfire and PSPS risk approaches and perspectives.

Context of Mitigation Deployments:

Party Comment: During SCE's 2022 pre-filing RAMP workshop, a member of The Utility Reform Network (TURN) commented that TURN hopes SCE will be addressing what is needed in RAMP pursuant to Row 26 of the S-MAP settlement. TURN indicated it would be helpful when talking about a mid-course mitigation program (such as covered conductor), to discuss the entire exposure in HFRA, and address how far along SCE is, and how SCE chose how much more needs to be addressed in light of accomplishments to date.

SCE Response: In this filing, SCE sets forth its Integrated Grid Hardening Strategy, which describes an approach to mitigate wildfire risk across the entirety of SCE's HFRA.

Party Comment: During SCE's 2022 pre-filing RAMP workshop, a member of the Public Advocates Office (Cal Advocates) requested that SCE put all of the RAMP Risk Chapter portions into context. For example, when SCE discusses covered conductor, SCE should also put it into context of the overall need in the different high fire threat areas, so parties can have the overall view of need/big picture rather than a snapshot.

SCE Response: In this filing, SCE sets forth its Integrated Grid Hardening Strategy, which describes an approach to mitigate wildfire risk across the entirety of SCE's HFRA.

PSPS Risk Modeling:

Party Comment: TURN indicated that it is not clear as to how PSPS is defined as a risk. TURN would appreciate more clarity about the definition of the risk event and the risk associated with PSPS.

SCE Response: In this RAMP filing, SCE quantified the potential Safety, Financial, and Reliability impacts (or attributes) of proactive de-energization events (see Table II-5) as required under D.21-11-009, Ordering Paragraph 1.h, p. 142 (stating that each IOU shall model PSPS events as risk events pursuant to the requirements in D.18-12-014). In addition, SCE proposes a series of measures to mitigate the potential impact of future PSPS events.

Party Comment: Cal Advocates indicated that the PSPS definition for evaluating risk should encompass the entire risk; it should not be limited or exclude specific things, or even exclude what may be discussed at the OIR. They urged SCE to consider all risks associated with PSPS, not just the operational elements of it. The PSPS mitigation may need GRC programs that may include sectionalization or redundancy in circuits. There could be a large area of GRC programs that can eliminate the need or impacts on SCE customers. SCE should take into account all of these impacts when accessing risks.

SCE Response: In this RAMP filing, SCE quantified the potential Safety, Financial, and Reliability impacts (or attributes) of proactive de-energization events (see Table II-5) as required under D.21-11-009, Ordering Paragraph 1.h, p. 142 (stating that each IOU shall model PSPS events as risk events pursuant to the requirements in D.18-12-014). In addition, SCE proposes a series of measures to mitigate the potential impact of future PSPS events.

Wildfire Risk Modeling:

Party Comments: Cal Advocates provided three recommendations from SCE's 2018 RAMP:

1. SCE should include guidelines that its staff follows to ensure proper classification of incidents to minimize the use of Driver 4 Unknown/Unspecified in the next RAMP filing.
2. It is recommended that SCE provide a full accounting for activities related to transmission wildfire risks in conjunction with its efforts related to its distribution assets.
3. A more refined risk analysis, circuit-by-circuit or line segment-by-line segment, would be worthwhile, especially for the Wildfire Covered Conductor Program (WCCP) where Index Scores have already been calculated by SCE.

SCE Responses:

1. In this RAMP filing, SCE has classified driver information based on the best data available. There may be many instances, where through no lack of due diligence on the part of SCE, the exact cause of an ignition may remain unknown.
2. SCE has accounted for wildfire ignition risk associated with transmission assets in this RAMP filing.

3. SCE has provided a circuit segment risk analysis for all mitigations proposed in this RAMP filing.

Alternative Plans:

Party Comment: Cal Advocates noted that the Alternative Plans presented in this Report (SCE's 2018 RAMP) need improvement and more sophistication from SCE.

SCE Response: SCE believes that we have provided two reasonable and realistic Alternative Plans for both Wildfire and PSPS risks as described above in Sections VIII. For example, for Wildfire risk SCE's Alternative Plan #1 is basically a "business-as-usual" approach that proposes no TUG work and continues with a covered conductor-centric wildfire risk mitigation grid hardening strategy. Alternative #2 increases the threshold for our risk tolerance to the consequences of wildfires. Both of these alternatives are feasible, realistic, and implementable. SCE does not ultimately agree that either of the alternatives represent the appropriate solution to pursue during this RAMP period, because they do not buy down enough absolute risk. However, the alternatives do provide the Commission, intervenors and other interested stakeholders with relevant data and analysis about the risk-cost tradeoffs inherent in choosing a mitigation plan to address the most important safety risk facing our customers and communities.

Similarly, for PSPS, we have set forth two reasonable, viable alternatives; namely increasing our risk tolerance (by raising the FPI threshold used when calling PSPS events) or providing more goods and services to customers when PSPS events are called. While, again, SCE ultimately does not feel that either alternative would be the optimal result, the two alternatives are implementable and relevant to an informed discussion about tradeoffs between risk avoidance, impact to customers, mitigation of drivers and mitigations of consequences, and the overlay of costs.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Contact with Energized Equipment

Chapter 5

Rosemead CA
May 13, 2022

Chapter 5: Contact with Energized Equipment

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Chapter 5: Contact with Energized Equipment

Table Of Contents (Continued)

I.

EXECUTIVE SUMMARY

A. Risk Overview

Southern California Edison (SCE) delivers electricity to over five million customers through our system of overhead conductor and underground cable. SCE's electrical system includes approximately 106,000 miles of primary overhead distribution conductor installed on poles throughout our service area. From distribution substations, electricity is transmitted via primary conductor to secondary conductor and then to individual service connections to end-use customers. In areas served by overhead infrastructure, energized distribution conductor is present on nearly every street, alley, thoroughfare, and residential property.

Exposure to the elements, contact with metallic balloons, vegetation intrusion, and windborne debris could all potentially cause an overhead conductor fault and wire-down event. SCE's distribution system is constructed with protection equipment that stops the flow of electricity when a foreign object contacts the line and causes a fault. If the fault is temporary, electricity flow can typically be restored relatively quickly (in seconds or minutes) through an automatic operation referred to as a circuit "reclose and retest." This reduces the need to deploy resources to manually reclose line sections.[1] If the fault is permanent or has resulted in damage to infrastructure, then the electricity flow will remain interrupted. This leads to a condition referred to as a circuit "lockout," and requires deploying field personnel to locate and repair the problem.

Over the last five years, SCE has experienced on average over 1,150 primary distribution conductor wire-down events per year. Some of these events involve energized wire-down, resulting in public safety exposure. Prior to SCE's Test Year (TY) 2018 General Rate Case (GRC), SCE recognized that a comprehensive program was necessary to adequately address the safety risks associated with

[1] Studies have shown that more than half of the faults on overhead distribution systems are temporary faults, or faults that clear themselves without needing additional repairs. Common examples of temporary faults include lightning, wind-driven conductor slapping, and animal contact. In reclosing, a protective device opens to clear a fault and then waits for a pre-determined period of time (e.g., 15 seconds) before attempting to close. If the fault was indeed temporary, then the protective device closes again, re-energizing the circuit and restoring service to customers served by the circuit. In such case, the circuit has successfully "reclosed."

overhead conductor failure, given the potential for a member of the public coming into contact with an energized wire-down. Intact wire-down events can also occur when overhead conductor has fallen low enough above the ground such that there could be accidental contact by the public.

Accordingly, in our TY 2018 GRC[2] SCE proposed a new Overhead Conductor Program (OCP) to replace and mitigate at-risk overhead conductor related to small-gauge wire exposed to fault current higher than rated capacity. SCE continued our funding request for the OCP program in the TY 2021 GRC.[3] Since 2018, SCE has not experienced a serious injury or fatality to members of the public due to a downed energized conductor. However, mitigating this public safety risk still remains a central safety focus for SCE, and the OCP helps prevent such injuries or fatalities from occurring in the first place.

In SCE's Wire-Down (WD) database, SCE tracks and captures event-specific details for overhead conductor failures that resulted in wire falling to the ground. This information is used in conjunction with outage and reliability information from our Outage Database and Reliability Metrics (ODRM) system, to identify and quantify risk drivers, outcomes, and consequences of wire-down events.

In addition to risks associated with wire-down events, risks are also associated with human contact with intact energized equipment. There have been approximately six events per year of contact by a member of the public with energized intact overhead or underground equipment (above and below grade).[4] Contact with energized intact equipment occurs when an individual makes contact with overhead or underground equipment while it is operating and situated as designed. These individuals can include high-risk workers such as tree trimmers or agricultural workers, as well as members of the general public. SCE continues to educate at-risk workers[5] on the dangers of working near electrified

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2 *See* SCE's Test Year 2018 General Rate Case, A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.

3 *See* A.19-08-013, Exhibit SCE-02, Vol. 1. Pt. 1, pp. 64–73.

4 Underground equipment can exist below grade in vaults, and conduits with cable, and above grade, as pad-mounted equipment or where cables in conduit rise up above grade, to serve meter panels and pedestals.

5 For purposes of RAMP modeling, at-risk workers are defined as workers who may not have been properly trained to work in close proximity to power lines.

equipment, and provides education and safety messaging to members of the general public who may interact with SCE's overhead and/or underground electrical equipment.

The risks associated with intact conductor are distinct from, but not unrelated to, the risks associated with wire-down events. In both cases, there is the potential for individuals to come into contact with energized conductor, with the possible consequence of serious injuries or fatalities.

In this chapter, we address the important safety risks associated with contact with energized equipment. SCE identified a number of compliance activities, controls, and mitigations to address the risks.[6]

This chapter evaluates three controls.

- Overhead Conductor Program (OCP) (C1): The OCP replaces small,[7] spliced, or damaged conductors with larger, more resilient conductors. This program helps limit the amount of damage that conductor may experience during fault conditions and lessens the probability of overhead conductor failure.
- Public Outreach – Wire-down and Intact Contact (C2 and C3): Public Safety Outreach focuses on mass marketing to educate and inform the public on actions to take and actions to avoid when encountering electrical safety hazards such as wire-down and contact with intact electrical equipment.

Finally, this chapter evaluates five mitigations:

- Non-HRFA Underground Conversion (M1): Non-HFRA Underground Conversion would involve converting portions of existing overhead circuits or lines to an underground system in non-HFRA.

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6 CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter 2 – Risk Model and RSE Methodology, compliance activities are not modeled in this report. Compliance activities are addressed in Section III. C = Control. This is an activity performed prior to or during 2022 to address the risk, and that may continue through the RAMP period. Controls are modeled in this report and are addressed in Section IV. M = Mitigation. This is an activity commencing in 2023 or later to affect this risk. Mitigations are modeled in this report and are addressed in Section V.

7 "Small" means small-gauge in this context.

- Early Fault Detection (EFD) (M2): EFD technology detects high-frequency radio emissions from arcing or partial discharge conditions on the electric system. This technology offers situational awareness of incipient faults and undesirable conditions on the electric system. Among other benefits, the technology facilitates promptly remediating or repairing the problematic condition or apparatus.
- Distribution Open Phase Detection (D-OPD) (M3): The D-OPD aims to detect one or more open phase (broken conductor) conditions on the distribution system.
- High Impedance (Hi-Z) (M4): The High Impedance relays utilize multiple protective elements to reduce wildfire ignition risks by detecting Hi-Z conditions such as downed conductors or arcing events.
- Rapid Earth Fault Current Limiter (REFCL) (M5): The REFCL technology detects when one wire out of a three-wire powerline has fallen to the ground. The technology almost instantly reduces the energy released to the ground.

For this RAMP Risk, SCE has developed and assessed three risk mitigation plans:

- The Proposed Plan continues existing programs (C1, C2, and C3).
    - Alternative Plan #1 continues existing programs (C1, C2, and C3) and includes M1 – Non-HRFA Underground Conversion.
    - Alternative Plan #2 continues existing programs (C1, C2, and C3) and includes several technology enhancement options in M2 – M5.

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Contact with Energized Equipment, based on the Proposed Plan discussed below.

Table I-1
***Summary of Pre- and Post- LoRE and CoRE Risk Scores*[8]**

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Contact with Energized Equipment - Wires Down	1,122	0.001	1.04	1,037	0.001	0.91
Contact with Energized Equipment - Intact Contact	5.7	0.19	1.09	5.7	0.19	1.09

II.

RISK ASSESSMENT

A. Risk Definition and Scope

Contact with Energized Equipment risk is defined as human contact with energized equipment potentially causing electrical shock to the public, including failure of overhead equipment resulting in a wire or other equipment down and contact with intact overhead and/or underground equipment by third parties (e.g., third-party tree trimmer). The scope of this risk chapter is further defined in Table II-2 below.

[8] Please refer to WP. Ch. 2 – RSE Summaries.

Table II-2
Contact with Energized Equipment Risk Scope

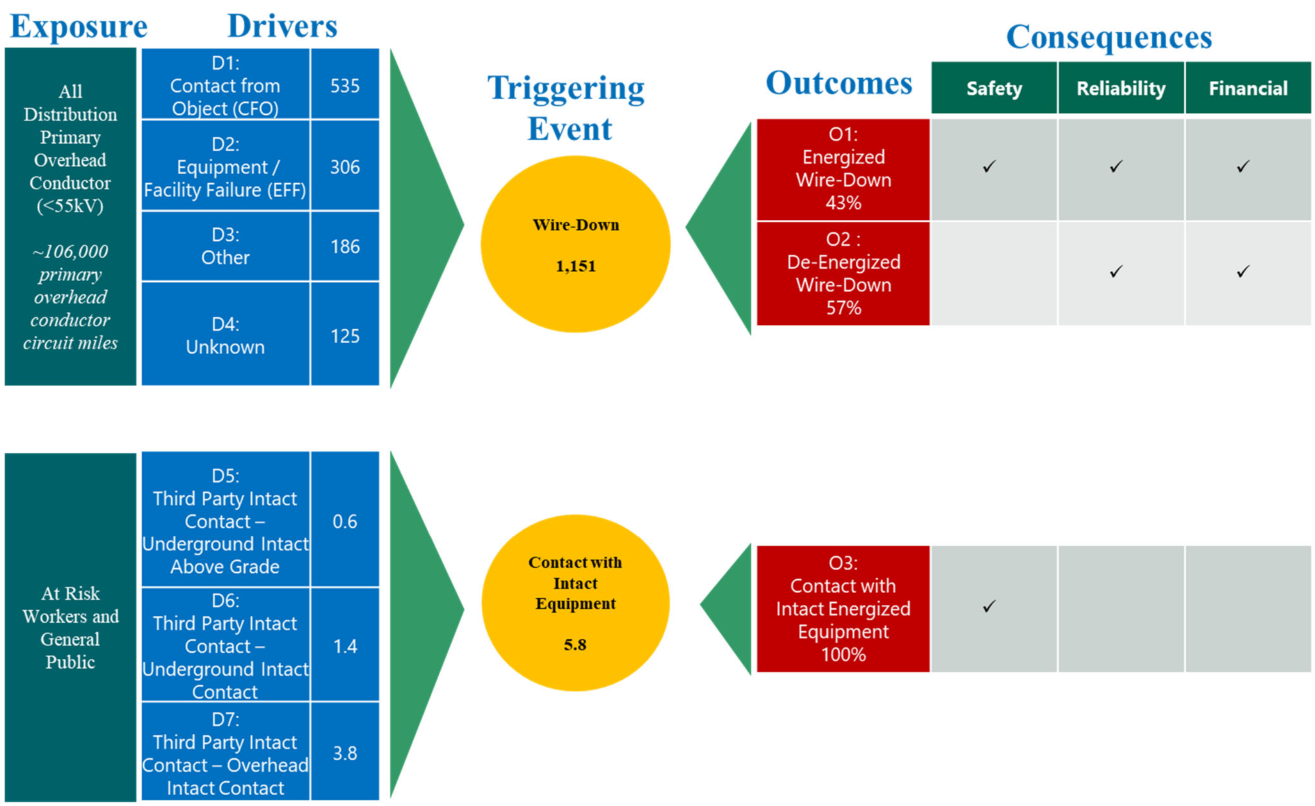
IN SCOPE	• Contact by a member of the public with energized overhead distribution primary conductor, when the conductor is a wire-down.* • Contact by a member of the public with energized intact overhead or underground equipment (above and below grade).
OUT OF SCOPE	• Contact with energized equipment by SCE employee or contractors.**
	• Contact with energized equipment during attempted theft of SCE equipment or property.
	• Contact with substation or transmission equipment or conductor.***

*For purposes of this chapter, wire-down events include situations where overhead conductor is physically on the ground, as well as events where overhead conductor is not physically on the ground but is low enough to touch.
**Chapter 9 - Employee Safety and Chapter 10 - Contractor Safety addresses the risks associated with SCE employees and contractors contacting energized overhead conductor.
***This risk is discussed in Appendix C - Transmission and Substation Asset Failure.

B. Risk Bowtie

To evaluate the Contact with Energized Equipment RAMP Risk, SCE has constructed two risk bowties as shown below in Figure II-1. These bowties identify two triggering events for this risk: 1) Wire-Down, and 2) Contact with Intact Equipment.

Figure **II-1**
Risk Bowtie for Contact with Energized Equipment[9]



SCE has identified the exposure of the wire-down risk as defined in Table II-2 and Figure II-1 as approximately 106,000 primary overhead distribution conductor circuit miles. The exposure for the contact with intact equipment is defined as the number of at-risk workers and the general public[10] that may interact with SCE's overhead and/or underground electrical system.

C. Drivers

SCE identified four primary drivers that lead to a wire-down. The four primary drivers are D1 – Contact from Object (CFO), D2 – Equipment/Facility Failure (EFF), D3 – Other, and D4 – Unknown.

As detailed below, we were able to subdivide two of these drivers (D1 – CFO and D2 –EFF) into sub-drivers. This subdivision provided greater granularity that helped us better understand the causes of

9 Please refer to WP. Ch. 5 – Baseline and Risk Inputs.

10 For purposes of RAMP modeling, the general public was assumed to be SCE's customer base of ~5,000,000.

this risk. SCE also identified three drivers that lead to the Contact with Intact Conductor and/or cable. These three drivers are:

- D5 – Third Party Intact Contact – Underground Intact Above Grade;
- D6 – Third Party Intact Contact – Underground Intact Contact; and
- D7 – Third Party Intact Contact – Overhead Intact Contact.

Table II-3 displays the annual frequency counts for each driver across the two bowties. SCE used its internal Wire-Down database to identify the frequency of drivers D1 through D4. These drivers are associated with the first bowtie that addresses this RAMP Risk. Data for the frequencies of D5 – D7 (Third Party Intact Contact) come from SCE internal records regarding public injuries or fatalities involving overhead and underground equipment. These drivers are associated with the second bowtie that addresses the RAMP Risk.

Table II-3
Historical Driver Frequency

RAMP Driver	Total (2017 - 2021)	Annualized Frequency	% of Driver Frequency
D1 - Contact from Object (CFO)	2,673	535	**46.2%**
D2 - Equipment / Facility Failure (EFF)	1,537	307	**26.6%**
D3 - Other	922	184	**15.9%**
D4 - Unknown	624	125	**10.8%**
D5 - Third Party Intact Contact – Underground Intact Above Grade	3	1	**0.1%**
D6 - Third Party Intact Contact – Underground Intact Contact	7	1	**0.1%**
D7 - Third Party Intact Contact – Overhead Intact Contact	19	4	**0.3%**
Totals	**5,785**	**1,157**	**100.0%**

1. <u>D1 – Contact from Object (CFO)</u>

CFO includes external factors that cause SCE's equipment to fail due to contact with foreign objects. The CFO driver also represents instances where SCE's equipment results in a wire-down event. Sub-categories of drivers identify the specific type of equipment that fails. Table II-4 below summarizes the annual frequencies of this driver and its sub-drivers.

Table II-4
D1 (CFO) Frequencies

CFO Sub-Drivers	Total (2017 - 2021)	Annualized Frequency	% of CFO Driver Frequency
D1a - Vegetation	715	143	26.7%
D1b - Animal contact	211	42	7.9%
D1c - Metallic balloon	560	112	21.0%
D1d - Vehicle contact	1,185	237	44.3%
D1e - Other	2	0.4	0.1%
Totals	**2,673**	**535**	**100.0%**

a) D1a – Vegetation

The Vegetation sub-category includes overhead conductor failures driven by contact with vegetation. This driver results from vegetation growing into the primary lines or when a branch or tree breaks and falls into SCE's overhead conductor. Airborne vegetation that blows into primary lines, particularly palm fronds, can also come in contact with SCE's overhead conductors, resulting in damage or a wire-down event.

b) D1b – Animal

Animals, such as birds and squirrels, frequently sit or walk on overhead conductors. In some instances, an animal makes the fatal move of contacting two phases of a circuit or contacting one phase of a circuit and a grounded portion of the circuit. This causes an equipment damage situation due to animal contact.

c) D1c – Balloons

Foil, foil-lined or metallic balloons can potentially damage overhead electrical equipment because of their conductivity. Current California law has recognized this and requires that all helium-filled metallic balloons be weighted to prevent escape and potential contact with overhead electrical facilities.[11] But serious risks remain (mostly associated with the general public not adhering to the weighted-anchor requirements after they purchase the balloons). When a metallic balloon contacts overhead lines, it can create a short circuit. This results in circuit damage, overheating, sparks/ignition, explosion, or a wire-down event.

d) D1d – Vehicle

The Vehicle sub-category includes overhead conductor failures caused by impact from motorized vehicles. This can occur when a passenger or commercial vehicle collides with our electrical equipment. This is often referred to as "car hit pole." The failure can result from energized overhead lines "slapping" together due to the impact of the collision, or from a pole being knocked over or broken from the impact.

e) D1e – Other

This Other sub-category includes all overhead conductor failures that are driven by malicious mischief or other actions by the public. This includes gunshot damage to conductors and contact from various objects such as drones.

2. D2 – Equipment / Facility Failure (EFF)

The "Equipment/Facility Failure" driver represents events caused by failure of SCE's equipment, independent of events listed in D1. This driver D2 EFF category includes sub-drivers which identify the type of equipment failure. Equipment failure sub-drivers include but are not limited to conductor, crossarm, and connector/splice pole. The result can be the conductor failing, which potentially creates a wire-down event. Table II-5 below summarizes the annual frequencies of this driver category and each sub-category. This table provides annualized frequency and percentage of all the sub-drivers of this driver category D2.

[11] Calif. Penal Code §653.1 (through 2012 Leg. Sess.)

Table II-5
D2 (Equipment / Facility Failure) Frequencies

EFF Sub-Drivers	Total (2017 - 2021)	Annualized Frequency	% of EFF Driver Frequency
D2a - Conductor	317	63	20.6%
D2b - Crossarm	120	24	7.8%
D2c - Connector / Splice	479	96	31.2%
D2d - Pole	164	33	10.7%
D2e - Other	457	91.4	29.7%
Totals	**1,537**	**307**	**100.0%**

a) D2a – Conductor

In general, there are two ways overhead conductor can experience equipment failure. The first way occurs when the system's short circuit duty (SCD) exceeds a conductor's rating over a defined time period (which is expressed as a curve based on conductor temperature). Generally, SCD indicates the relative strength of an electrical system, typically measured by the current (in amps) that the system can supply when fault conditions occur. If at any given point in the system fault current exceeds the conductor's ability to withstand it, then fault conditions can damage, weaken or melt the conductor and lead to conductor failure. This represents a risk of a wire-down event. Older and smaller conductor is especially vulnerable to damage during fault conditions. Typically, this old/small conductor possesses a lower conductor rating, or current-carrying capacity, compared to larger conductor.

The second way is conductor fatigue. Conductor fatigue refers to the decrease in overhead conductor's ability to withstand forces experienced during operational conditions.
For overhead wire, the likelihood of fatigue-related failures tends to increase over time, as the conductor is exposed to longer periods of operational stress. This can occur when overhead conductors are subjected to higher short-term emergency ratings to accommodate higher-loading conditions. An

example is when we must transfer customers between adjacent circuits during circuit restoration procedures, in order to reduce the number of customers affected by an outage.

Beyond the operating conditions described above, the conductors could also be exposed to very high-magnitude short circuit current when there is a fault condition further downstream in the circuit. Even though these short circuit currents are typically very brief in duration (usually less than 1 second), the extremely high current level can result in a rapid increase in localized temperature of the conductor and will contribute to the conductor experiencing fatigue-related failures at some point in its lifetime.

Any of the conditions mentioned above can cause an energized conductor to fail. A wire-down event can occur as a result.

b) <u>D2b – Crossarm</u>

Crossarms are mounted on distribution poles. They are used to support overhead conductor or other pieces of overhead distribution equipment. As crossarm pieces weaken or deteriorate over time, either the crossarm can break or the bracket that attaches the crossarm to the pole can fail. In either case, conductor can come into contact with:

- Other conductors
- The pole
- Other pieces of electrical equipment
- The ground

Alternatively, the conductor may be energized and intact, but physically drop low enough to be accessible to members of the public. This is also characterized as a wire-down event.

c) <u>D2c–Connector/Splice</u>

Connectors and splices are different types of equipment or material used as a connection for overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector. Spans of conductor are connected to other spans of conductor with a splice. Both types of equipment or material are subject to degradation due to over-torquing during installation, high short circuit duty, age, and exposure to the elements.

d) D2d – Pole

Pole failures that lead to wire-down events typically occur when there is deterioration at the top of the pole. Pole deterioration can take place at any location on a pole and may not be visible during inspection. SCE's intrusive pole inspection program and pole loading assessments cannot effectively test for, or detect, deterioration at the top of the pole.

e) D2e – Other

This driver includes other EFF sub-drivers not previously encompassed, such as guys, lightning arrestors, potheads and taps. These types of equipment can deteriorate from age, use, and exposure to the elements.

3. D3 – Other

The Other driver includes activities where SCE or its contractors were not responsible for a wire-down event. There is a distinction between this driver and the risks assessed in the Employee Safety and Contractor Safety RAMP Risk chapters. The events in this chapter include consequences associated with damage to SCE infrastructure, but not the consequences associated with any injuries to SCE workers or contractors that may occur while replacing or repairing failed equipment. Table II-3 above summarizes the annual frequency of this driver category.

Additionally, the Other category (D3) includes overhead conductor failures that are driven by malicious mischief, vandalism (excluding theft), or other actions by the public such as contact from various objects such as drones, wire-to-wire contamination, weather, and structure fires.

4. D4 – Unknown

In some circumstances, the cause of a wire-down event is not identifiable by SCE. This can occur for a variety of reasons. One example is when emergency personnel secure the area prior to SCE's arrival. A second example occurs when the offending object is blown or thrown from the location and cannot be traced to the incident; this can occur in cases of animal contact. It is also possible that there is no apparent cause for the failure, and rather than entering a "best guess," the cause is simply categorized as unknown. Table II-3 above summarizes the annual frequency of this driver category.

5. D5 - Third Party Intact Contact – Underground Intact Above Grade

When a human contact occurs with intact energized above-grade underground equipment, the result can be a serious injury or fatality to a member of the public as a result of explosion or electrical shock (e.g. third-party contractor or public contact). An example of this occurs when a member of the public contacts pad-mount equipment. Pad-mount equipment primarily consists of cable and components, transformers, switches capacitor banks. Other above-grade equipment includes meters and meter panels. The data for this driver is based on SCE internal records regarding injuries or fatalities involving the public interacting with our system. SCE identified an average of 0.6 events per year from 2017 through 2021.

6. D6 - Third Party Intact Contact – Underground Intact Contact

This driver occurs when human contact with underground equipment below grade results in a serious injury or fatality to a member of the public as a result of explosion or electrical shock (e.g., third-party contractor or public contact). Underground equipment primarily consists of cable and components, transformers and switches. The data for this driver is based on SCE internal records regarding injuries or fatalities involving the public interacting with our system. SCE identified an average of 1.4 events per year from 2017 through 2021.

7. D7 - Third Party Intact Contact – Overhead Intact Contact

When human contact with intact overhead conductor is made this can result in serious injury or fatality, and/or damage to SCE's electrical system. This can occur when overhead conductor is contacted by someone working in close proximity to SCE equipment, such as a tree trimmer. Or the situation can occur in connection with heavy equipment operations for earth work or other construction activities, where mechanical arms are extended upwards and make contact. Agricultural equipment operating in fields also have increased risk of contact, due to the nature of the equipment types being used. Extension poles utilized for finishing concrete, or other projects where "extend out" tools are used, also present an elevated risk of contact. The data for this driver is based on SCE internal records regarding injuries or fatalities involving the public interacting with our system. SCE identified an average of 3.8 events per year from 2017 through 2021.

D. Triggering Events

SCE has identified two triggering events for the Contact with Energized Equipment risk.

1. Wire-Down – This event occurs when an energized conductor is on the ground, or is energized and intact but is low enough to allow the public to contact it. This triggering event is shown in the first bowtie presented earlier in this chapter. Based on SCE's Wire-Down database, this triggering event has an average frequency of 1,151 events per year from 2017 to 2021.
2. Contact with Intact Equipment – This event occurs when an individual, or third party, makes contact with: (a) SCE's overhead conductor, (b) other intact energized equipment above grade, or (c) intact energized underground equipment. In each of these three situations, the SCE apparatus is operating correctly and as designed. Based on SCE internal records, this triggering event has an average frequency of 5.8 events per year from 2017 to 2021.

E. Outcomes and Consequences

SCE identified three outcomes that represent the basic conditions that exist for contact with energized equipment. This includes overhead conductor failing in service and falling towards the ground. The outcomes also encompass a member of the public making contact with intact overhead conductor, intact above grade underground equipment, or intact underground equipment.

1. O1 – Energized Wire-Down

This outcome occurs when a wire-down event has taken place, protective devices have not detected the wire-down condition, and manual intervention is required to interrupt the energized wire-down event. SCE's distribution system is designed and built with protection to stop the flow of electricity under fault conditions, to remain de-energized under conditions of permanent faults or equipment damage without manual patrol or intervention by field personnel, and to reclose under conditions of temporary faults which do not cause infrastructure damage. This protection approach is intended to prevent accidental contact with overhead conductor by de-energizing the conductor prior to or immediately upon contact with the ground. This is successful when there is enough fault current to be detected by system protective devices.

However, under certain conditions, wire-down events can be difficult to detect by protective devices. For example, challenges can occur when a wire-down event takes place on high-resistance surfaces such as asphalt, concrete, or very sandy or rocky soils. These conditions are referred to as "high impedance fault conditions," and can result in lower fault current magnitudes than we can readily detect. High impedance fault conditions with wire-downs may not be automatically cleared by protective devices. Instead, these conditions may need to be detected through other means such as customer calls, Meter Alarm Down Energized Conductor (MADEC),[12] 911 calls, or circuit patrol activities. These conditions also may need to be interrupted by manual intervention of Troublemen or other field personnel. Additionally, a wire-down event can occur when an intact energized conductor has fallen and is within reach of the public.

SCE utilized MADEC data collected in 2020 to estimate the percentage of wire-down events that remain energized for primary distribution conductor. This data is reflected in the O1 and O2 outcome percentages in Figure II-1.[13] Energized wire-down information from MADEC is only available at locations with available smart meter data. In locations where MADEC data is unavailable, SCE conducts engineering studies to determine whether the wire upstream of the wire-down location was damaged based on available SCD and conductor damage curves.

In order to calculate the safety consequences associated with a wire-down event, SCE used CPUC-reportable incidents resulting in serious injuries or fatalities to the public. SCE used the data from ODRM to calculate the customer minutes of interruption (CMI) for each wire-down event. To estimate the financial consequences, SCE used internal work orders for priority one (P1) repair costs associated with the wire-down everts.[14]

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[12] The MADEC algorithm relies on machine learning to detect meter signatures that indicate energized wire-down events in real time.

[13] The MADEC data is inclusive of primary wire-down and does not include sub-transmission lines or secondary lines; this approach is consistent with the scope of this risk event as described above in Section II.A.

[14] SCE excluded certain repair order costs for explosion events that did not have an associated P1 notification, or were associated with storm incidents such that other repair costs were bundled with this work.

2. O2 – De-Energized Wire-Down

O2 considers wire-down events where protective devices have detected the wire-down condition and automatically de-energized the wire-down event. As described previously, SCE's distribution system is built with protection designed to stop the flow of electricity under fault conditions, to lockout under conditions of permanent faults or equipment damage, and to reclose under conditions of temporary faults that do not cause infrastructure damage. This protection is intended to prevent accidental contact with overhead conductor by de-energizing the conductor prior to or immediately upon contact with the ground. This is successful when there is enough fault current to be detected by system protective devices.

As a result of the protective device operation, SCE believes the potential safety consequences associated with a de-energized wire-down event are relatively *de minimis*. Therefore, SCE has not modeled any safety consequences in this outcome. SCE used the data from ODRM to calculate the customer minutes of interruption (CMI) for each wire-down event. To estimate the financial consequences, SCE used internal work orders for priority one (P1) repair costs associated with the wire-down everts.[15]

3. O3 – Contact with Intact Energized Equipment

This outcome occurs when human contact with intact energized underground equipment, or overhead electrical equipment that is energized and physically close enough to the ground to allow the public to make contact it. The ultimate result can be serious injury or fatality to a member of the public. Reliability and Financial consequences have been excluded from the modeling.

F. Tranches

1. Wire-down Events

The tranching for contact with energized equipment is asset-based. This approach provides more granular information and homogeneity across risk tranches. SCE has developed risk models down to the asset level. We select overhead spans for replacement based on the high safety risk

[15] SCE excluded certain repair order costs for explosion events that did not have an associated P1 notification, or were associated with storm incidents such that other repair costs were bundled with this work.

data from the CEE Risk Model;[16] this method substantially determines the scope for the Overhead Conductor Program. In our workpapers, SCE is providing risk spend efficiencies (RSEs) at the circuit-segment level. However, for purposes of readability and straightforward presentation in the chapter itself, SCE shows RSEs at the control and/or mitigation level.

The prioritization for the scope of OCP is determined by the product of high consequence scores multiplied by a high probability of failure. This prioritization methodology focuses on reducing the greatest safety risk first. However, in practice, some adjustments to the prioritization may be required to levelize work across SCE's service area.

2. Intact Contact

Risk of contact with intact equipment is tranched into At-Risk Worker and the General Public. At-Risk Workers are defined as third-party contractors, tree workers, and agricultural workers, since these groups have the greatest probability of encountering electrical equipment.

G. Related Factors

For purposes of this discussion, SCE defines related factors as factors that are not directly included in the risk modeling but can impact the driver frequency and the likelihood of certain outcomes. Some considerations are:

- **Changes in Operating Conditions** – Operating conditions such as high peak loading or exposure to fault conditions can change the risk profile of electrical equipment by increasing their effective age. Higher effective age is correlated with higher probability of failure. Unforeseen changes in operating conditions could have an impact on the overall risk profile for underground equipment.
- **Changes in population density** – Population density factors into the probability of a negative outcome. If the population density changes, it could alter the risk profile of certain areas. For example, the state of California is already seeing early trends that some populations are moving from city centers to more rural counties. If these trends persist, there

[16] Refer to WP Ch. 5-Contact with Energized Equipment Risk Model Overview.

could be an increase in the risk profile of previously lower-population areas. Also, California has recently passed laws[17] to increase available housing units by allowing for more accessory dwelling units (ADUs), as well as subdividing lots and replacing single family units with multi-dwelling units. The newer laws could result in existing low-density residential areas transforming into medium- or high-density residential areas.

III.

COMPLIANCE

SCE has existing compliance programs and processes in place to mitigate this risk. These compliance activities are not modeled in this risk analysis, but are discussed below.

A. CM1 – Distribution Deteriorated Pole Remediation Program

SCE's Distribution Deteriorated Pole Remediation Program captures the costs to replace our steel stubbing distribution poles that have failed an intrusive pole inspection.

This program proactively identifies poles that represent an increased probability of pole failure. Through this program, SCE takes action to replace these poles with new assets or to make repairs to meet pole design standards and criteria. Thus, this compliance program reduces the frequency of pole-related drivers of wire-down events.

B. CM2 – Intrusive Pole Inspections (IPI) Program

The IPI Program is required for SCE's approximately 1.4 million wood poles, which are located in varying climate regions throughout SCE's 50,000 square-mile service territory. Environmental factors such as decay, fungi, and insect attacks may cause degradation of the inner portion of a wood pole. This inner degradation may not be detectible by visual inspections. SCE established the IPI Program to comply with GO 165, which became effective in 1997.

1. Intrusive Pole Inspections

General Order (GO) 165 requires intrusive inspections for all poles by the time they reach 25 years in-service, and then requires re-inspection at least once every 20 years. SCE's IPI program

[17] 2017 - Senate Bill (SB) 1069, Assembly Bill (AB) 2299 AB 2409; 2020 - AB 881, AB 670, SB 13, AB 68; 2021 - SB 9.

began in 1997, and the first cycle was completed by 2009. SCE also began transitioning to a 10-year inspection grid-based cycle (approved by the Commission) that meets or exceeds GO 165 requirements. SCE completed its first grid-based cycle inspection in 2018. GO 165 defines intrusive inspections as "involving movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading." Intrusive inspections involve drilling into the pole's interior to identify and measure the extent of internal decay, which is typically undetectable with external observation alone.

SCE's inspection standards describe six types of inspections satisfying this definition; the activities apply different combinations of digging, boring, and sounding depending on the type of pole and its setting. The IPI program is also required in order to comply with Rule 44.2 of GO 95, which mandates that pole loads calculated in anticipation of additional construction incorporate the results of an intrusive inspection completed within the previous 5 years for wood poles older than 15 years.
In addition to meeting the requirements of GO 165 and GO 95, SCE inspectors also perform visual inspection on poles that are younger than 10 years old, to look for signs of obvious external damage, such as damage from vehicles or woodpeckers.

2. Pole Loading Assessments

Pole loading assessments are performed to determine a pole's safety factor. Pole loading assessments require a field assessment, as well as a desktop analysis that uses an application to calculate each pole's safety factor. Inputs include the physical attributes of the pole and its attachments, as well as local wind conditions. The field assessment measures or validates the pole's attributes (such as species, size and type) and conductor size, along with other equipment the pole may be supporting.

C. CM3- Pole Loading Program (PLP)

SCE assesses poles through its Pole Loading Program (PLP) to identify and repair or replace poles that do not meet GO 95 loading, temperature and safety factor requirements. The Pole Loading Program (PLP) was approved in Decision 15-11-021 as a comprehensive program to address pole loading issues. PLP assessments began in January 2014. The initial focus was on the highest risk areas, including high fire areas. SCE completed assessments on the entire system in 2021; however, residual work remaining on poles requiring remediation is expected to continue through 2025. Pole loading assessments are performed to determine a pole's safety factor. As stated above, pole loading assessments require a field assessment and a desktop analysis to calculate each pole's safety factor.

D. CM4 – Vegetation Management

SCE's Vegetation Management Program has been in place for many years to meet the requirements of GO 95 and other compliance requirements. These activities help minimize faults (and resulting ignitions and outages) triggered by vegetation contacting energized electrical facilities. These activities also help prevent wire-down events associated with vegetation contact. The programs include the pre-inspection of trees, as well as preventative vegetation trimming to maintaining compliance clearances near SCE electric facilities. These programs also include tree removal, pole brushing, commercial orchard topping, and, in more recent years, weed abatement. This compliance-related work is distinct from the incremental Expanded Vegetation Management mitigation activities and efforts, which reduce risk and are not required by law or regulation. The Hazard Tree Management Program (HTMP) falls under this category.

SCE manages vegetation in accordance with several regulations, including General Order (GO) 5 Rules 35 and 37, Public Resources Code Sections 4292 and 4293, and FERC FAC-003-2. To comply with these requirements, SCE engages a contractor to inspect, trim or remove trees and weeds, and handle other activities.

During vegetation inspections, any tree or vegetation that need to be remediated to maintain the required distances from high-voltage lines are scheduled to be pruned. In addition, trees with hazardous conditions and damaged/diseased trees are also identified for pruning. Sometimes SCE must trim trees more frequently to meet the Commission's requirements for tree-to-line clearances between annual trim cycles. Fast-growing species, or trees in areas designated as high-risk for wildfires, may need more frequent pruning to meet the Commission standards.

Besides the vegetation management efforts described above, SCE also removes dead, dying, and diseased trees. Because of the drought emergency, SCE increased work activities associated with inspecting and removing dead, dying, or diseased trees that could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent encroachment, large dead or dying trees can be located outside of the right-of-way and still fall into power lines. This significantly increases the number of trees that can pose a hazard to our customers and the communities we serve.

E. CM5 – Overhead Detailed Inspection, Apparatus Inspections, and Preventative Maintenance

SCE's Overhead Detailed Inspection and Preventative Maintenance are activities included under SCE's Distribution Inspection and Maintenance Program (DIMP). The goal of DIMP is to meet the requirements of GO 95, 128, and 165 in a way that: (1) follows sound maintenance practices; (2) enhances public and worker safety while maintaining system reliability; and (3) delivers overall greater safety value for each dollar spent. This allows SCE to focus its limited resources on higher-priority locations. These activities address all distribution overhead assets in the SCE system.

DIMP enables us to prioritize work based on the condition of each facility or piece of equipment and its potential for impact on safety and reliability, considering various factors such as facility or equipment loading, location, accessibility, and climate. DIMP helps SCE prioritize resources effectively and efficiently to remediate conditions that potentially pose higher risks. This approach follows the Commission's requirements as set forth in GO 95 and a memorandum of understanding between SCE and the CPUC's Safety and Enforcement Division.

DIMP has three maintenance priority levels. During inspections, SCE inspectors identify issues and rate conditions observed, taking into account the factors previously described. The highest priority issues requiring immediate action are assigned Priority 1 (P1). A Priority 1 has an immediate risk of high potential impact to safety or reliability. Priority 2 (P2) items are the second level of priority. These P2 items require corrective action within a specified time period. Priority 1 and Priority 2 items may be fully repaired, or temporarily repaired or reclassified as a lower priority item upon partial remediation. Priority 3 (P3) items are lower priority issues; namely, those that involve little or no safety or reliability risk. While Priority 3 items do not require immediate action, they do require corrective action within 60 months.[18] A summary of the DIMP maintenance priority levels is provided in Table III-6.

Table III-6
Summary of Maintenance Priority Levels

Category	Safety/Reliability Issue Identified	Condition Details	Action
Priority 1	Yes	Immediate action required	Same day/Immediate action
Priority 2	Yes	Immediate action not required	Action within 0-24 months (Non-High Fire Areas) Action within 0-12 months (High Fire Areas)
Priority 3	No	Specific GO 95 / issue identified	Action within 60 months
None	No	No GO 95 / 128 issue identified	Monitor condition during course of inspection cycles

In addition to DIMP, SCE also performs Apparatus Inspections and Maintenance. SCE's apparatus inspection and maintenance program is designed to support SCE's commitment to providing a safe and reliable electrical distribution system by maintaining proper functionality and operation of the apparatus equipment. This program performs the inspection, testing, and maintenance of overhead and underground distribution apparatus used for remote monitoring and control. Examples of distribution apparatus include capacitors, regulators, network protectors, fault interrupters, and automatic re-closing switches used for line protection and sectionalizing.

These activities proactively identify existing assets that require mitigation. These compliance controls reduce the frequency of equipment-related drivers of wire-down events.

IV.

CONTROLS

In addition to the compliance work discussed above, SCE has identified three controls that are included in the risk analysis. These are shown in Table IV-7.

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[18] *See* D.18-05-042 for the decision to amend Rule 18 of GO 95 requiring Priority 3 maintenance items to be corrected within 60 months (effective June 30, 2019).

Table IV-7
Contact with Energized Equipment RAMP Controls

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
C1	Overhead Conductor Program	D1, D2	-	-	Yes	All
C2	Public Outreach - Wires Down	D1c	O1	Safety	Yes	All
C3	Public Outreach - Intact	D6, D7	-	-	Yes	All

A. C1 – Overhead Conductor Program (OCP)

SCE's OCP involves replacing smaller-gauge conductor with larger-gauge conductor. The OCP is an existing control that SCE began performing in 2015. This program has continued through SCE's 2021 GRC. The OCP control C1 mitigates the risk of Driver D1 (CFO) by reducing the number of faults that lead to wire-down events.

The upgrades we perform in the course of OCP create a more resilient system that will be less susceptible to damage as a result of such faults. Additionally, control C1 mitigates risk associated with wire-down events by reducing the frequency of Driver D2 (Equipment / Facility Failure). OCP replaces small, spliced, or damaged conductor with larger, more resilient conductor. Reconductoring provides the benefit of removing splices from existing bare conductor where splices exist.

A core theme to the OCP strategy is an understanding of short circuit duty (SCD). As discussed earlier in this chapter, SCD generally indicates the relative strength of a system, typically measured by the fault current (in amps) that the system can supply at any location within the system. For older overhead wire installations, existing levels of SCD can result in increased risk of conductor damage during fault conditions. Since it is not currently possible to determine the extent of conductor damage on in-service overhead conductor from previous faults, the OCP C1 mitigation addresses this problem by reconductoring smaller-gauge wire to larger-gauge wire. Using larger conductor provides the benefit of being able to withstand existing levels of SCD while reducing the risk of conductor damage during fault conditions. Increasing the wire size to mitigate wire-downs may lead to equipment upgrades such as larger poles and crossarm replacements/reconfiguration, which also help reduce operational risks.

The current deployment plan for this control includes replacing approximately 911 circuit miles from 2025 – 2028, or an average of 228 circuit miles a year. These levels are subject to change based on year-to-year scoping details, resource constraints, and other factors.

1. Drivers Impacted

The OCP is designed to reduce the triggering event frequency associated with Drivers D1 (CFO), and D2 (EFF). OCP will reduce the frequency of wire-down events associated with D1 by replacing small, spliced, or damaged conductor with larger, more resilient conductor. In other words, OCP may not necessarily reduce the frequency of faults, but it should reduce the number of faults that lead to wire-down events. Faults listed in D1 are external events that will continue to occur regardless of the OCP. The OCP upgrades SCE will perform will create a more resilient system that will be less susceptible to damage as a result of such faults.

2. Outcomes and Consequences Impacted

The OCP will not impact outcomes or consequences in the risk model.

B. C2 – Public Outreach -Wire-down

This control includes Mass Media Public Safety Outreach. SCE's Public Safety Outreach focuses on educating and informing the public on actions to take and avoid when encountering electrical safety hazards, including downed electrical wire and metallic balloon in contact with electrical wires. Examples of these outreach efforts include billboards, television, radio, digital media, social media, signage in stores, signage on SCE vehicles, community outreach, and information distributed at community events. SCE's outreach materials are translated into Spanish, Chinese, Korean and Vietnamese to align with the diverse customer demographics in our territory.

SCE monitors its outreach effort through the Customer Attitude Tracking Survey, a year-round survey conducted by a third party. Over the past decade, awareness of this safety messaging among SCE's customers has been steadily increasing, from 34% approximately ten years ago, to 52% in 2021. SCE personnel also work with elementary schools to teach children proper safety around electrical lines.

This interaction with young students encourages them to share the information with their families, providing greater impact for the message of safety around energized lines.

SCE also provides electrical safety workbooks to schools to teach children about the subject in a fun and informative way. Additionally, SCE's "e-SMART" website[19] engages young people (third grade through tenth grade) on topics related to electricity. Through interactive videos, games, and activities, the website invites visitors to become "e-SMART" by learning about the science of electricity and how to stay safe when in proximity to our facilities.

1. Drivers Impacted

This control can also reduce the frequency of D1c – metallic balloons through education of the public of the dangers of metallic balloons near conductors as described above.

2. Outcomes and Consequences Impacted

SCE models Public Outreach – Wires Down as reducing the safety consequences associated with Outcome O1 (Energized Wire-Down) in the top bowtie. This is based on the assumption that energized wire-down would be less likely to result in serious injury or fatality consequences to the public through proactive messaging, education, and awareness for how to work around, respond to, and avoid contact with energized conductor.

C. C3 – Public Outreach – Intact Contact

This control includes two activities: (1) Mass Media Public Safety Outreach, and (2) At-Risk Worker Safety Outreach related to contact with intact electrical equipment.

The At-Risk Worker Safety Outreach is designed to drive behavioral changes of working around electrical equipment. The program is targeted at three distinct audiences: third-party contractors, tree workers, and agricultural workers. These groups have the greatest probability of encountering electrical equipment.

Focus groups, surveys, interviews, and studies are used to create program objectives and inform the development of communication strategies and tactics. Multiple communication channels that build

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[19] *See* https://sce.e-smartkids.com/.

upon each other are used to educate and create awareness, encourage action, and elicit behavioral change. Distributed literature and materials focus on best practices around overhead and underground lines, strongly recommending using qualified tree trimmers, contacting Dig Alert[20] prior to excavation, and using a spotter when construction activities will occur near electrical facilities.

Education and training are provided via mailers, flyers, videos, and other online vehicles to reach the respective audiences in ways that resonate with them. Some materials are created in both English and Spanish. The program includes built-in feedback loops and data collection to gauge effectiveness and make improvements based on the data. Some of the effectiveness measures include retention rates, recall, open/read rates, and application of the safety information being communicated.

1. Drivers Impacted

Public Outreach – Intact is expected to reduce the frequency of public contact with SCE electrical equipment. The Mass Media Public Safety Outreach activity educates the public in a manner that reduces the frequency of all Third-Party Intact Contact drivers (D5, D6 and D7). The At-Risk Worker Safety Outreach activity educates contractors, agricultural workers, and tree trimmers on how to avoid contact with energized equipment. This should reduce the frequency of all Third-Party Intact Contact drivers (D5, D6 and D7).

2. Outcomes and Consequences Impacted

Public Outreach - Intact does not impact outcomes or consequences in the risk model.

V.

MITIGATIONS

In addition to compliance and control activities mentioned above, SCE has identified potential new and innovative ways to mitigate this risk, to further reduce the frequency and/or impact of the risk event. Table V-8 summarizes these activities, and further details are provided in the sections below.

20 *See* https://www.digalert.org/.

Table V-8
List of Contact With Energized Equipment Mitigations

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
M1	Non-HFRA Underground Conversion (NHUC)	All	-	-	No	Alternative Plan #1
M2	Early Fault Detection (EFD)	D1, D2, D3	-	-	No	Alternative Plan #2
M3	Distribution Open Phase Detection (D-OPD)	-	-	Safety	No	Alternative Plan #2
M4	Hi Impedance (HI-Z)	-	-	Safety	No	Alternative Plan #2
M5	Rapid Earth Current Limiter (REFCL)	-	-	Safety	No	Alternative Plan #2

A. M1 – Non-HFRA Underground Conversion (NHUC)

1. Description

SCE continues to investigate the possibility of undergrounding certain overhead circuits as a measure of reducing the CEE Risk. For purposes of this RAMP chapter, this mitigation would focus on the undergrounding of circuits outside of SCE's HFRA.[21] Non-HFRA Underground Conversion would involve converting portions of existing overhead circuits or lines to underground circuits or lines. An overhead-to-underground conversion involves removing all aboveground equipment, such as poles, conductor, transformers, and switches. We then install underground conduit, cable, vaults, manholes, transformers, and switches.

Undergrounding electric facilities can be challenging and may require multiple designs based on specific geographic factors. The amount of work and challenges involved make undergrounding a relatively high-cost mitigation.

2. Drivers Impacted

Non-HFRA Underground conversion was modeled as addressing all overhead drivers in this risk statement. This is based on a key underlying assumption – that the risk drivers considered in this chapter are substantially associated with overhead assets. Certain new risks would be introduced

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[21] *See* Chapter 4 – Wildfire / PSPS for further discussion on targeted underground conversion in HFRA.

into the system with underground conversion. For example, people who are digging near underground electrical assets may be exposed to "dig-in" risks of contact with energized underground cable. The new risks that would be introduced with underground conversion were not modeled in this analysis.

3. Outcomes and Consequences Impacted

Non-HFRA Underground Conversion will not impact outcomes or consequences in the risk model.

B. M2 - Early Fault Detection (EFD)

1. Description

Early Fault Detection (EFD) is a mitigation that could be used on the distribution system for non-HFRA wire-down events. EFD sensors can continuously monitor lines and proactively detect undesirable, degraded or pre-failure system conditions. The sensors measure radio frequency electrical discharges that travel along the wire when an issue is present. The EFD system uses the measurements to provide locations of concern on the electrical system so that further evaluation can be carried out. The follow-up may include proactive remedial action. Completing these remediations/repairs prior to complete failure may prevent fault events that could lead to an ignition, and that often result in customer electric service outages.

2. Drivers Impacted

EFD alerts correspond to degraded and undesirable conditions on electrical facilities. These conditions include broken conductor strands, vegetation contact, degraded connections/splices, and insulator degradation. EFD can detect conditions for repair which may not be found with traditional inspection methods, or alternately may be found sooner or more efficiently with the use of the EFD technology. EFD impacts D1 (CFO), D2 (EFF) and D3 (Other).

3. Outcomes and Consequences Impacted

EFD will not impact outcomes or consequences in the risk model.

C. M3 - Distribution Open Phase Detection (D-OPD)

1. Description

SCE is investigating a Distribution Open Phase Detection (D-OPD) scheme to detect one or more open phase (broken conductor) conditions on the distribution system in non-HFRA. The advanced protection detection scheme focuses on reducing ignitions associated with wire-down incidents, for both bare and covered conductor systems. The capabilities should allow the protection system to isolate a separated conductor prior to the wire contacting the earth, while leveraging the standard distribution hardware.

SCE will use Remote Sectionalizing Recloser (RSR) and Remote Automatic Recloser (RAR) installations to detect separated conductor(s). The RSR or RAR will be used as the device that will detect when a separated wire event occurs. Once a separated wire event is detected, the RSR or RAR will rapidly communicate to an upstream RAR where the protection device will open the recloser and de-energize the portion of the circuit where the separation of conductor occurred. For the pilot, setting configuration changes are made to both locations with the algorithm to detect and isolate separated conductor events. Communication equipment installations are added to both devices in order to allow for direct communication between the devices.

The pilot effort will provide SCE with valuable information for understanding the potential for additional outages caused by the use of this more sensitive circuit protection system. The costs, functionality, and testing of unknowns (such as interference of other radios) of the new communication components are being evaluated during the pilot.

2. Drivers Impacted

D-OPD is able to detect the isolation of energized lines prior to the lines contacting ground. The D-OPD system is expected to reduce the number of energized wire-down events. However, implementing D-OPD does not affect any drivers, since it does not actually prevent the occurrence of conductor falling to the ground.

3. Outcomes and Consequences Impacted

D-OPD also has the ability to identify and isolate an open phase condition within 1.2 seconds,[22] reduce the number of energized wire-down events, and address system reliability impacts from false detections with an operational OPD scheme.

D. M4 – High Impedance (HI- Z)

1. Description

High Impedance (Hi-Z) is a potential mitigation on the distribution system for wire-down events in non-HFRA. Hi-Z conditions exist on high-resistance surfaces such as asphalt, concrete, or very sandy or rocky soils. Detecting Hi-Z conditions is an industry-wide challenge. SCE's traditional feeder protection elements are based on overcurrent, meaning that the protection elements rely on fault magnitude to trigger the relay to operate. In a Hi-Z event, however, the fault magnitude is relatively small to non-existent. Therefore, protection schemes that can detect Hi-Z conditions can reduce the propagation of low-magnitude fault conditions, and therefore reduce public safety risk. High Impedance Relays utilize multiple protective elements with protection schemes to detect Hi-Z conditions such as downed conductors or arcing events. SCE is still validating the technology's efficiency in the field in detecting actual Hi-Z events.

2. Drivers Impacted

SCE has demonstrated that the High Impedance (Hi-Z) Relay technology can detect Hi-Z conditions in a lab testing environment. Hi-Z does not affect any drivers, since it does not prevent the occurrence of conductor falling to the ground.

3. Outcomes and Consequences Impacted

High Impedance Relays utilize protection schemes that are able to detect Hi-Z conditions and some low magnitude/high impedance faults. The detection of low magnitude fault conditions, which are not detectable with traditional protection schemes, is important. Detecting these issues sooner can

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[22] Using the freefall equation, 1.2 seconds is the estimated time it would take for a Distribution conductor to hit the ground after separating.

reduce safety consequences. Low magnitude faults can lead to ignitions, high magnitude faults, or various other issues.

E. M5 – Rapid Earth Fault Current Limiter (REFCL)

1. Description

SCE is evaluating the use of Rapid Earth Fault Current Limiter (REFCL) technologies as a mitigation in non-HFRA on the distribution system for wire-down events. REFCL is effective in reducing energy from ground faults and can detect ground faults as small as a half ampere on one phase of a three-phase circuit. REFCL reduces the voltage on the faulted line while boosting the voltage on the two remaining phases, so that we can maintain service for customers while extinguishing arcs. However, while REFCL is effective at reducing energy from a phase-to-ground fault, it does not mitigate phase-to-phase faults.

Although REFCL technology is compatible with bare wire, covered conductor, or underground distribution systems, it has a relatively high cost. SCE is assessing the most cost-effective alternative solutions. These can vary, because SCE's system is not homogenous and the solution may require different configurations based on circuit topology at different sites. Further discussion of REFCL technology can be found in Chapter 4 – Wildfire and PSPS RAMP chapter (for HFRA applications).

2. Drivers Impacted

REFCL does not affect any drivers, since it does not prevent the occurrence of conductor falling to the ground.

3. Outcomes and Consequences Impacted

REFCL technology has been found to substantially reduce the energy released in ground faults, and therefore has the potential to significantly reduce the risks of public safety exposure to energized downed wire.

VI.

FOUNDATIONAL ACTIVITIES

Through the RAMP process, SCE did not identify any activities that are considered foundational that support Contact with Energized Equipment that are not already included in the respective program costs. SCE will continue to investigate if any other work activities should be considered foundational prior to filing our TY 2025 GRC.

VII.

PROPOSED PLAN

SCE has evaluated the controls and mitigations identified in Sections IV and V above, and we have developed a Proposed Plan for mitigating the risk of contact with energized equipment. Table VII-9 below displays the specific choices for SCE's Proposed Plan.

Table VII-9
Proposed Plan (Total Costs in Millions and 2025 Risk Spend Efficiencies)[23]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1	Overhead Conductor Program	-	$502.84	72.0
C2	Public Outreach - Wires Down	$3.74	-	5.0
C3 - T1	Public Outreach - Intact (At Risk Wokers)	$0.37	-	200.7
C3 - T2	Public Outreach - Intact (General Public)	$1.94	-	20.3
Total		**$6.05**	**$502.84**	**-**

23 Please refer to WP. Ch. 2 – RSE Summaries and WP. Ch. 5 – Contact with Energized Equipment Financials.

Table VII-10
Pre- and Post- LoRE, CoRE and Risk Scores[24]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Contact with Energized Equipment - Wires Down	1,122	0.001	1.04	1,040	0.001	0.95
Contact with Energized Equipment - Intact Contact	5.7	0.19	1.09	5.7	0.19	1.09

A. Overview

The Proposed Plan to mitigate CEE risks includes continuing existing OCP mitigation over the RAMP period. The Proposed Plan also includes ongoing Public Outreach (C2 and C3). This effort allocates funding to provide educational resources and public safety messaging to help alleviate contact risks when the members of the public encounter a downed electrical wire. Public Outreach also includes the actions taken to inform at-risk workers such as third-party contractors, agricultural workers, and first responders regarding the dangers of working around energized equipment and downed wires.

B. Execution Feasibility

Executing OCP (C1) is feasible as it relies on highly mature work processes, well-understood equipment types, and established work methods. SCE has a high degree of confidence in its ability to target, execute, and derive benefit from the OCP program when paired with bare conductor. SCE has executed at levels consistent with the average being proposed in this plan. Executing public outreach (C2 and C3) is feasible, since it reflects continuity in executing a control activity that is in place today.

C. Affordability

The Proposed and Alternative Plans require the same level of funding. The Proposed Plan continues funding for mitigation that are existing public safety programs at levels relatively consistent with what SCE proposed in its 2021 GRC.

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[24] Please refer to WP. Ch. 2 – RSE Summaries.

D. Other Considerations

While the Proposed Plan only includes bare-to-bare conductor OCP replacements, SCE may consider opportunities for bare-to-covered conductor replacement outside of HFRA, in order to mitigate CEE risk. In the Wildfire and PSPS Chapter, SCE is not taking into account any additional ancillary costs and/or benefits that covered conductor may have for non-wildfire safety risks.

VIII.

ALTERNATIVE PLANS

A. Alternative Plan #1

SCE has evaluated two alternative plans to mitigate the Contact with Energized Equipment risk. Alternative Plan #1 is shown in Table VIII-11 below. The pre- and post-mitigation risk scores are presented by tranche in Table VIII-12.

Table VIII-11
Alternative Plan #1 Addressing Contact with Energized Equipment Risk[25]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1	Overhead Conductor Program	-	$452.56	80
C2	Public Outreach - Wires Down	$3.74	-	5
C3 - T1	Public Outreach - Intact (At Risk Wokers)	$0.37	-	200.7
C3 - T2	Public Outreach - Intact (General Public)	$1.94	-	20.3
M1	Non-HFRA Underground Conversion (NHUC)	-	$50.28	42
Total		**$6.05**	**$502.84**	**-**

[25] Please refer to WP. Ch. 2 – RSE Summaries and WP. Ch. 5 – Contact with Energized Equipment Financials.

Table VIII-12
Pre- and Post- LoRE, CoRE and Risk Scores[26]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Contact with Energized Equipment - Wires Down	1,122	0.001	1.04	1,034	0.001	0.91
Contact with Energized Equipment - Intact Contact	5.7	0.19	1.09	5.7	0.19	1.09

1. <u>Overview</u>

Alternative Plan #1 reflects the possibility of reallocating a percentage of capital spend from the existing OCP (C1) mitigation strategy to conduct Non-HFRA Underground Conversions (NHUC) (M1). As shown above in Table VIII-11 and Table VIII-12, adding M1 would provide a larger overall risk reduction since underground cable would significantly reduce or eliminate risk from all drivers (D1, D2, D3, D4). However, the RSE compared to the existing mitigations C1, C2 & C3 appears to be lower because of the relatively high cost of undergrounding (without the corresponding ignition-avoidance benefit because here it would be located in non-HFRA).

2. <u>Execution Feasibility</u>

The conversion of overhead circuit(s) to underground is a common scope of work across SCE's service area and has been successfully deployed as a risk mitigation on a limited basis to date where overhead conductor, pole and equipment failures represent an elevated ignition risk. SCE currently converts overhead lines to underground in compliance with Tariff Rules 20A, 20B, and 20C. In cities where undergrounding is required, SCE will install all new construction in compliance with the city's requirements. This would be a new mitigation for SCE because there are currently no programs which specifically target converting overhead to underground lines to address contact with energized equipment risks.

[26] Please refer to WP. Ch. 2 – RSE Summaries.

3. Affordability

The results shown in Table VIII-12 indicate that while the mitigation of non-HFRA undergrounding would reduce certain driver risks, the overall risk reduction is comparable to the Proposed Plan with similar overall spending.

4. Other Considerations

SCE will continue to evaluate the approach taken in Alternative Plan #1. As appropriate and as feasible based on overall resource constraints, SCE may make certain limited and discrete proposals in our GRC next year that reflect Alternative Plan #1. SCE did not identify any other considerations that are not discussed above.

B. Alternative Plan #2:

SCE has evaluated a second Alternative Plan to mitigate the Contact with Energized Equipment risk. Alternative Plan #2 is shown in Table VIII-13 below with the pre- and post-risk scores in Table VIII-14.

Table VIII-13
Alternative Plan #2 Addressing Contact with Energized Equipment Risk [27]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1	Overhead Conductor Program	-	$452.56	80
C2	Public Outreach - Wires Down	$3.74	-	5
C3 - T1	Public Outreach - Intact (At Risk Wokers)	$0.37	-	201
C3 - T2	Public Outreach - Intact (General Public)	$1.94		20
M2	Early Fault Detection (EFD)		$12.57	9
M3	Distribution Open Phase Detection (D-OPD)		$12.57	21
M4	Hi Impedance (HI-Z)		$12.57	50
M5	Rapid Earth Current Limiter (REFCL)		$12.57	299
Total		**$6.05**	**$502.84**	**-**

Table VIII-14
Pre- and Post- LoRE, CoRE and Risk Scores [28]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Contact with Energized Equipment - Wires Down	1,122	0.001	1.04	1,037	0.001	0.91
Contact with Energized Equipment - Intact Contact	5.7	0.19	1.09	5.7	0.19	1.09

[27] Please refer to WP. Ch. 2 – RSE Summaries and WP. Ch. 5 – Contact with Energized Equipment Financials.

[28] Please refer to WP. Ch. 2 – RSE Summaries.

1. Overview

Alternative Plan #2 combines current CEE Controls with new technology enhancements. The technology enhancements included in this plan include: Early Fault Detection (EFD, M2), Distribution Open Phase Detection (D-OPD, M3), High Impedance (HI-Z, M4) and Rapid Earth Current Limiters (REFCL, M5). A detailed description of each technology can be found in Section V.

The enhancements considered under Alternative Plan #2 (M2-M5) represent strategies for prevention and increased situational awareness through early fault detection and automated de-energizations in response to conditions that drive negative CEE outcomes. EFD sensors enable the prevention of faults by monitoring early indicators of fault conditions. D-OPD and HI-Z technologies seek to resolve hard-to-detect fault conditions and prevent downed wires from remaining energized. SCE is also exploring REFCL technology to provide situational awareness to mitigate the risk from active arcing events increase without deenergizing the circuit.

Mitigations (M2-M5) are still being evaluated and are considered to still be in the pilot stage as opposed to technologies approved for full-scale deployment.

2. Execution Feasibility

EFD, OPD and REFCL mitigation strategies have been deployed as pilot programs in HFRA under WMP applications. HI-Z technology has also been tested and shown to be effective at identifying high impedance conditions in laboratory environment, but enough field testing has not been conducted to determine the effectiveness for CEE applications.

3. Affordability

While SCE is continuing to investigate a broader application outside of HFRA, data supporting the effectiveness of the mitigation does not have sufficient granularity to provide accurate RSE justifications to divert capital spend allocations from the existing mitigation programs. The current affordability of REFCL solutions has a low cost-effectiveness for CEE applications.

4. Other Considerations

Future deployment of any technology solution requiring substation or field installed sectionalizers, reclosers, and sensory equipment, or the reprogramming of such equipment, will require coordinated testing and investigation with adjacent strategies utilizing the same equipment underneath different use cases in the WMP and RAMP. The allocation of capital spend will need to be assessed and potentially prioritized by the RSE of mitigations in those use cases.

IX.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

SCE appreciates the benefits of evaluating new technologies. New technologies such as EFD, D-OPD, Hi-Z and REFCL represent mitigations for CEE risk in Alternative Plan #2. These technologies seem promising but are currently not yet mature. They are in the pilot stage, and we must assess them further before undertaking any full-scale deployment.

B. Data Collection and Availability

While SCE continues to improve its ability to determine if a wire-down was automatically de-energized, acquiring data in this regard remained a challenge for this RAMP filing. The primary focus of our first responders to a wire-down event is ensuring the safety of the public and themselves. The after-the-fact documentation of whether a wire-down was energized or not can be challenging, due to the lack of data capture at the time that first responders arrive at the scene, secure it, and take other urgent steps.

As indicated in our 2018 RAMP, SCE used information from our Wire-Down Database. This database contained a significant amount of "unknown" or "blank" records as to whether the conductor was energized on the ground. This presented a challenge for RAMP modeling purposes. Wire-down data was documented by field personnel who are first to arrive on scene. Documenting whether a wire-down was energized at the time it initially came down, based on observations in the field, can be a subjective endeavor. This is particularly true in cases where the wire is not energized when first responders arrive. In other words, there can be cases when a wire-down was initially energized, but by the time first responders arrived it had ceased to be so.

Also, it can be nearly impossible to determine when the conductor struck the ground relative to when the circuit relayed (i.e., de-energized). In lieu of complete records, SCE conducted a study based on a sample of 2020 events to determine the rate of energized wire-down events.

In our 2018 RAMP, SCE indicated that the continued development of more advanced high impedance fault detection techniques will help determine if a wire down was energized and could further refine the actual distribution of outcomes O1 and O2 in the system for future filings. As a result of the 2020 events study that was performed, SCE developed a Meter Alarm of Down Energized Conductor (MADEC) algorithm.

The MADEC algorithm relies on machine learning to detect meter signatures that indicate energized wire-down events in real time. The precision of this detection method may improve as the algorithm is enhanced by further information based on more observed events over time. In this 2022 RAMP, SCE used information from MADEC, as described above in Section II.E.1, to estimate the percentage of wires down remaining energized. SCE will continue to build upon our capabilities to determine energized wire-down events

C. Performance Metrics

SCE tracks a significant amount of data related to wire-down events. Table IX-15 below summarizes some key performance metrics related to wire-down events; however, this is not an exhaustive list. The table also indicates whether any of these metrics are included in SCE's annual Safety Performance Metrics (SPM) report[29] and if there is any relationship to the RAMP bowtie and/or risk analysis.

[29] This is based on the updated list of SPMs from D.21-11-009, Appendix B.

Table IX-15
List of Contact with Energized Equipment Performance Metrics

Metric	Leading / Lagging Indicator	Included in SPM Report	Metric Directly Included in Risk Bowtie	Bowtie Element	Description / Definition
T&D Overhead Wires-Down (MED and non-MED Days)	Lagging	Yes	Yes	This directly informs the triggering event frequency of the risk bowtie.	Number of instances where an electric primary distribution conductor is broken, or remains intact, and falls from its intended position to rest on the ground or a foreign object on "Major Event Days" (typically due to severe storm events) as defined by the IEEE.
Wires-Down not resulting in Automatic De-energization	Lagging	Yes	Yes	This directly informs the percentages of Outcomes 1 and 2	% or number of instances where an electric primary distribution conductor wire down did not result in automatic de-energization by circuit protection devices such as fuses, circuit breakers, and reclosers, etc. on all portions of a downed conductor that rest on the ground.
Missed Inspections and Patrols for Electric Circuits	Leading	Yes	No	-	Annual number of overhead electric structures that did not comply with the inspection frequency requirements divided by total number of overhead electric structures with inspections due in the past calendar year.
GO-95 Corrective Actions Completed On Time	Leading	Yes	No	-	The number of Priority Level 2 notifications that were completed on time divided by the total number of Priority Level 2 notifications that were due in the calendar year. Consistent with GO 95 Rule 18 provisions, the proposed metric should exclude notifications that qualify for extensions under reasonable circumstances.
Outage minutes due to wire-down events	Lagging	No	Yes	Informs the reliability consequence of a wire down event	The number of customer minutes of interruption per wire down event.

Additionally, SCE has identified useful metrics to track effectiveness in executing programs that impact contact with wires-down and intact electrical equipment.

- Circuit miles of OCP projects completed[30]
- Percentage of At-Risk workers reached from public outreach

30 SCE also reports out on the authorized and recorded annual spending amounts and work units for OCP in our annual Risk Spending Accountability Reports (RSAR).

X.

ADDRESSING PARTY FEEDBACK

SCE received several recommendations from parties in our 2018 RAMP relating to the Contact with Energized Equipment RAMP chapter. SCE directly addressed these items in our 2021 GRC direct or supplemental testimony.[31] No party provided any work product that expressed any concern or disagreement with the SCE GRC testimony. In addition, SCE did not receive any direct feedback when SCE presented on the CEE Risk in our RAMP Pre-Filing workshop.

[31] SCE addressed Safety Enforcement Divisions recommendations in our direct testimony in A.19-08-013 and recommendations from Cal Advocates and The Utility Reform Network in Exhibit SCE-11 Supplemental Testimony on Risk Informed Strategy & Business Plan.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Underground Equipment Failure

Chapter 6

Rosemead CA
May 13, 2022

Chapter 6: Underground Equipment Failure

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Chapter 6: Underground Equipment Failure

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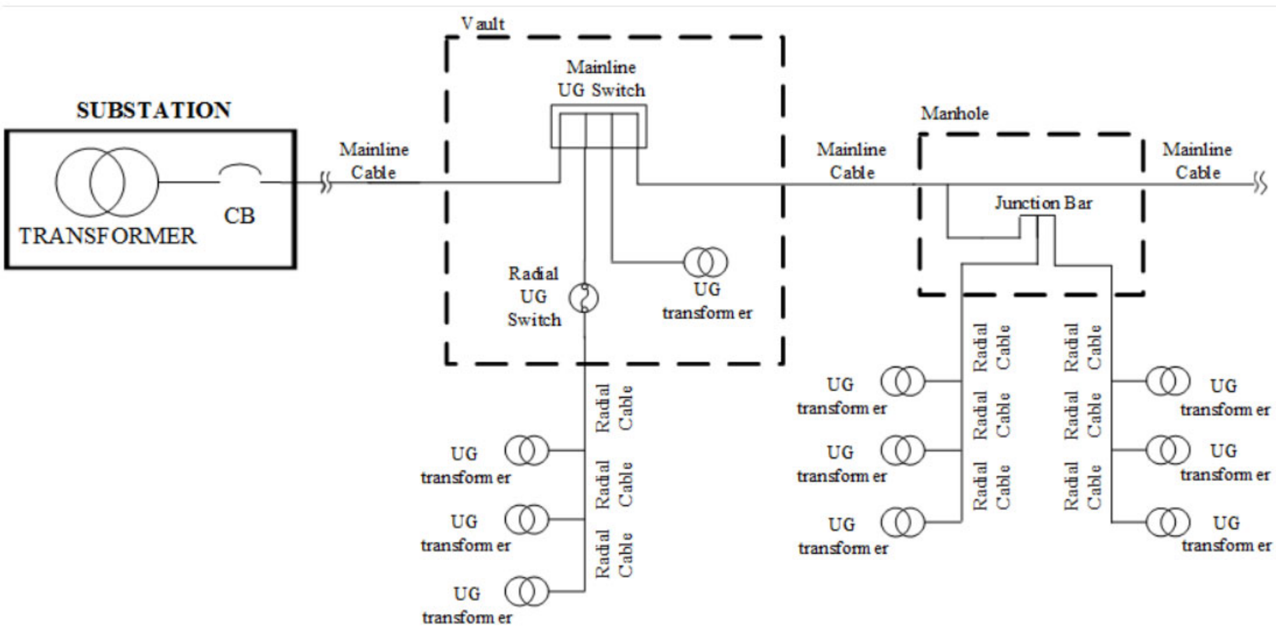
I.

EXECUTIVE SUMMARY

A. Risk Overview

Approximately half (44%) of SCE electric distribution system primary conductor miles are installed underground.[1] Underground electrical components include cable, conductor, transformers, and switches. These components are installed above or underneath nearly every street in SCE's 50,000 square-mile service area. This includes sites in close proximity to high traffic areas such as schools, residential neighborhoods, shopping malls, community centers, and entertainment venues. For reference, a simplified representation of SCE's underground distribution system is provided in Figure I-1.

Figure I-1
Simplified Representation of SCE's Underground Distribution System



As described in SCE's Test Year (TY) 2021 General Rate Case (GRC),[2] the equipment installed in SCE's underground vaults can degrade or deteriorate over time as a result of age, wear, and exposure to the environment. In addition to these factors, underground equipment can be damaged when foreign

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1 *See* A.16-09-001, Exhibit SCE-02, Vol. 8, p. 21, Table III-5; p. 48, line 1.

2 *See* A.19-08-013, Exhibit SCE-02, Vol. 01 Pt. 1, pp. 16-17.

materials enter the vaults through small openings; in some limited cases, members of the public inadvertently may have improperly disposed of items such as motor oil or cleaning solvents.

In addition to expected reliability impacts associated with in-service failures, underground equipment failure could also impact public safety. These components are generally contained within enclosed structures such as manholes or vaults. Once any of these components fail, the resulting fault energy can interact with combustible gases which have built up in those locations, leading to a violent explosion. These explosions can forcibly dislodge a vault or manhole cover from its frame, causing damage to streets, property, and/or injury to nearby workers (utility and non-utility) or members of the public.

SCE has experienced underground equipment failures resulting in explosions, fires, and smoke events. The risk is not unique to SCE. An article in IAEI[3] Magazine states as follows: "Across North America, an estimated 2,000 manhole events occur each year, an average of 5.5 events per day. With the current state of aging infrastructure in most cities, this frequency is likely to increase unless utility companies take preventive measures"[4]

Recent vault explosions in SCE's service territory include the following events:

- SCE's Covina District, October 23, 2017 – Cable on a distribution circuit failed. This resulted in a vault explosion violently displacing a manhole lid causing damage to the structure, the street, multiple vehicles, and nearby homes.
- SCE's Huntington Beach District, October 6, 2019 – An apparent underground electrical vault explosion occurred in Old World Village. Two firefighters at the scene were injured and treated at a local burn center.
- SCE's Huntington Beach District, November 29, 2019 - An apparent underground electrical vault explosion took power out in parts of South Coast Plaza in Costa Mesa. This left shoppers in the dark for almost two hours during the Black Friday shopping rush.

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[3] IAEI stands for International Association of Electrical Inspectors.

[4] *See* https://iaeimagazine.org/electrical-safety/manhole-events-practicing-prevention.

- SCE's Valencia District – February 25, 2020 - Cable on a distribution circuit failed, resulting in a BURD[5] switch failure.

SCE identified a number of compliance activities, controls, and new mitigations to address these risks and threats.[6] This chapter evaluates four controls.

- Worst Circuit Rehabilitation (WCR) (C1): The WCR program seeks to improve the reliability performance of SCE's worst performing circuits. The program uses advanced cable failure models and risk analysis to target those cables for replacement. Generally, the WCR program focuses on mainline cable replacements.
- Cable Replacement Programs (Cable-In-Conduit) (C2): The Cable-In-Conduit program utilizes information obtained through the associated Cable Life Extension program to target cables for replacement.
- Underground Switch Replacement Program (C3): The Underground Switch Replacement program removes old oil-filled underground distribution switches located in underground structures, and replaces them with newer-technology switches.
- Cover Pressure Relief and Restraint (CPRR) Program (C4): The CPRR program mitigates safety risks associated with explosions in underground structures by replacing older conventional vault covers with SCE's newer CPRR standard equipment.

Finally, this chapter evaluates two mitigations:

- BURD Transformer Replacement (M1): The BURD transformer replacement program preemptively replaces BURD transformers based on the safety risk profile of specific locations.

[5] BURD means Buried Underground Residential Distribution.

[6] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter 2 – Risk Model and RSE Methodology, compliance activities are not modeled in this report. Compliance activities are addressed in Section III. C = Control. This is an activity performed prior to or during 2022 to address the risk, and it may continue through the RAMP period. Controls are modeled in this report and are addressed in Section IV. M = Mitigation. This is an activity commencing in 2023 or later to affect this risk. Mitigations are modeled in this report and are addressed in Section V.

- Fault Indicators (M2): Fault Indicators help identify the phase and location of fault activity, usually in the form of a light, when fault current is present.

SCE has developed three risk mitigation plans:

- The Proposed Plan continues the four existing Controls (C1, C2, C3 and C4).
    - Alternative Plan #1 continues existing Controls (C1, C2, C3 and C4) and includes M1 - BURD Transformer Replacement
    - Alternative Plan #2 continues existing Controls (C1, C2, C3 and C4) and includes M2 – Fault Indicators.

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Underground Equipment Failure, based on the Proposed Plan discussed below.[7]

***Table* I-1**
Summary of Pre- and Post- LoRE and CoRE Risk Scores[8]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Underground Equipment Failure	1,955	0.0010	1.96	1,820	0.0009	1.71

II.

RISK ASSESSMENT

A. Risk Definition and Scope

In this chapter, SCE evaluates the risk of its underground electrical equipment failing. SCE has constructed a risk bowtie to quantify the potential safety, reliability, and financial consequences resulting from this risk.

7 LoRE – likelihood of risk event. CoRE – consequence of risk event. Risk Score is the product of the LoRE and CoRE. For additional information on the risk modeling methodology, please refer to Chapter 2 – Risk Model and Methodology.

8 Please refer to WP. Ch. 2 – RSE Summaries.

The scope of this risk chapter is defined below in Table II-2.

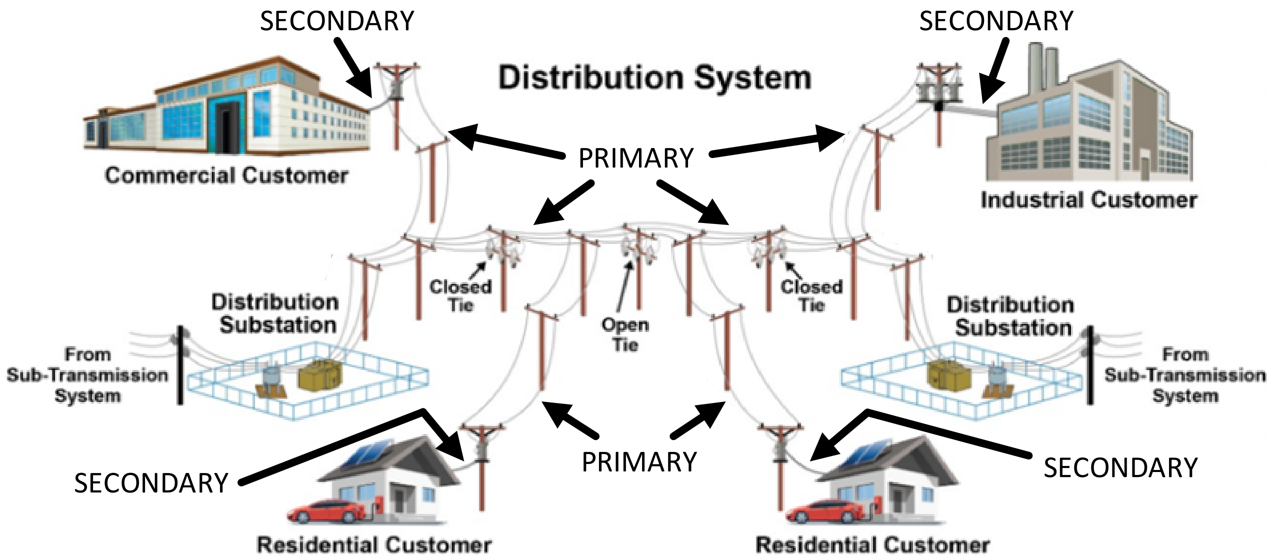
Table II-2
Underground Equipment Failure Risk Scope

IN SCOPE	All underground structures that contain primary distribution undergound electrical equipment that when fail could potentially lead to an explosion event.
OUT OF SCOPE	Events initiated by human performance (which would be covered in Chapter 9 – Employee Safety and Chapter 10 - Contractor Safety);
	Failure of pad-mounted* UG electrical equipment;
	Secondary distribution systems.

** - Pad-mounted generally refers to electrical equipment that is mounted on a concrete pad.*

This scope includes equipment failures on SCE's primary distribution system, and excludes failures on SCE's secondary distribution systems. The term "primary" refers to the high-voltage side of distribution transformers, typically 4 kV, 12 kV, 16 kV and 33 kV. The term "secondary" refers to the low-voltage side of distribution transformers, typically 480 V or less. Figure II-2 below is a simplified diagram of the SCE distribution system illustrating the distinction between primary distribution and secondary distribution elements. Figure II-2 below depicts distribution concepts which apply to overhead as well as underground facilities.

Figure II-2
Illustration of Typical Primary and Secondary Distribution Systems



B. Risk Bowtie

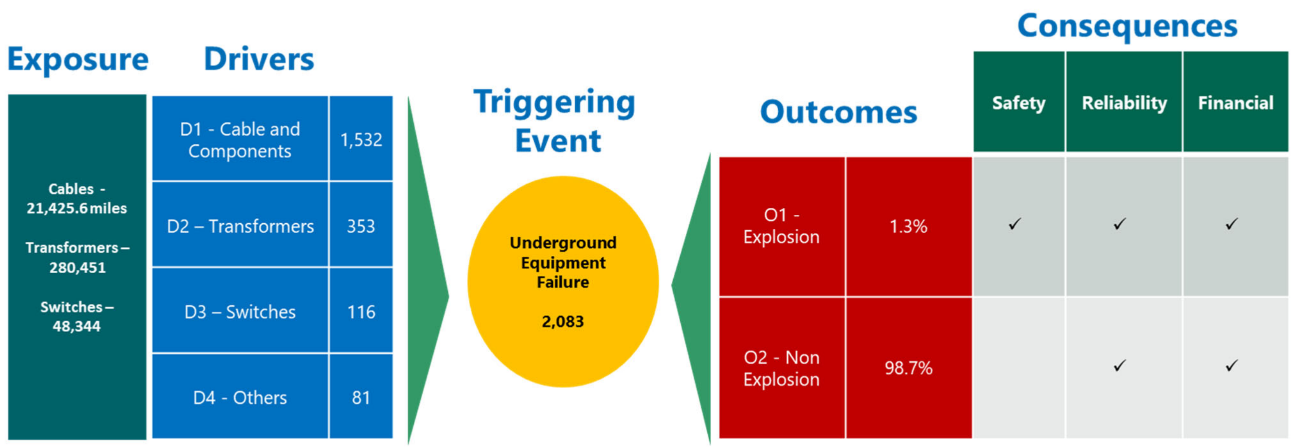
To evaluate the risk of underground equipment failure, SCE has constructed an Underground Equipment Failure (UEF) risk bowtie (see Figure II-3). The UEF bowtie describes the overall exposure, risk drivers, triggering events, outcomes, and consequences. Additional details on each part of the bowtie are provided in the sections below.

The bowtie we present below closely resembles the bowtie that SCE presented in our 2018 RAMP report. SCE has made some relatively minor updates to the driver side of the bowtie.
The previous bowtie included cable and components, transformers, and switches as sub-drivers under the driver D1 – Major Equipment Cause.[9] For the 2022 RAMP, SCE believes it is appropriate to separately include those items as drivers as well, in order to better highlight the major equipment involved for this risk.

[9] *See* SCE 2018 RAMP Report. Chapter 11 – Underground Equipment Failure, p. 11-7.

The total exposure for this risk is defined as 21,426 miles of underground cable, 280,451 transformers and 48,344 underground switches.[10]

Figure II-3
Risk Bowtie for Underground Equipment Failure[11]



C. <u>Drivers</u>

For the 2022 RAMP, SCE identified four different drivers on its primary distribution system: Cable and Components, Transformers, Switches, and Others. SCE used its Outage Database and Reliability Metrics (ODRM) system to identify driver frequencies. The ODRM system collects information on all distribution interruptions such as outage location, duration, cause, and number of customers impacted. SCE uses this information to calculate system reliability metrics such as System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). Table II-3 below provides historical frequency of this driver category.

[10] UG switches include Pad Mounted Equipment (PME), Rocker Arm Ground (RAG), Rocker Arm Mechanical (RAM), BURD, and Molded Vacuum Switch (MVS) switches.

[11] Please refer to WP. Ch. 6 - Baseline and Risk Inputs.

Table II-3
Historical Driver Frequency

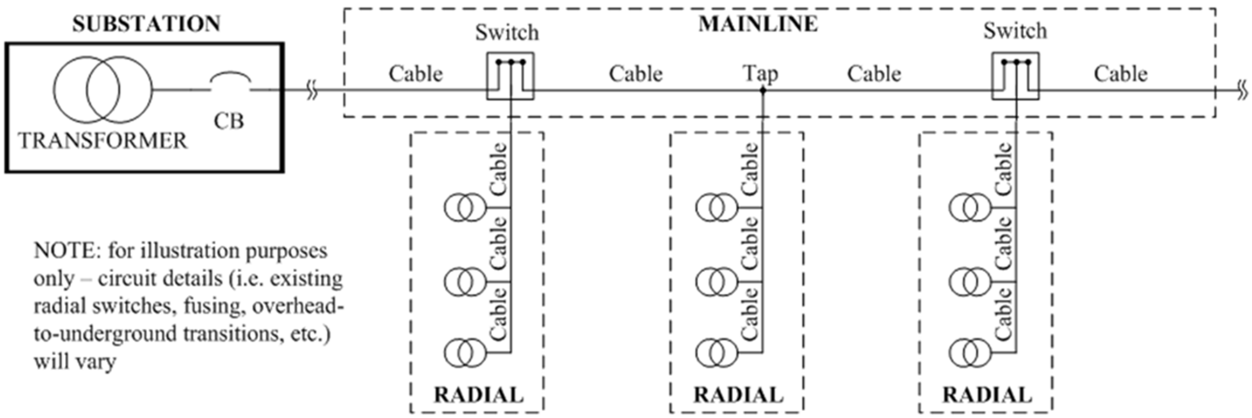
RAMP Driver	Total (2017 - 2021)	Annualized Frequency	% of Driver Frequency
D1 - Cable and Components	7,662	1,532	73.6%
D2 - Transformers	1,765	353	16.9%
D3 - Switches	582	116	5.6%
D4 - Other	404	81	3.9%
Totals	**10,413**	**2,083**	**100.0%**

1. D1 - Cable and Components

This driver category includes in-service failures of distribution cable and related cable accessories, such as elbows, junction bars, and splices. This includes the failure of primary voltage distribution cable in both mainline and radial applications. Based on 2017-2021 ODRM data, SCE's system has experienced an annual average of 1,532 failures of cable and cable accessories (approximately 74% of the total annual observed UG Equipment Failures). Approximately 42% of these 1,532 failures are mainline cable failures, and approximately 58% are radial cable failures. Table II-3 above provides historical frequency of this driver category.

Figure II-4 below illustrates mainline and radial cable on a typical distribution circuit. Failure of mainline cable tends to impact more customers, whereas radial cable failures are limited to fewer customers and result in less customer minutes of interruption.

Figure II-4
Mainline and Radial Cable Illustrated on a Typical Underground SCE Circuit



Cross-linked polyethylene (XLPE) cable was SCE's standard primary distribution cable installed between years 1970 through 1999. This type of cable represents approximately half of all primary voltage underground distribution cable installed in the SCE system. For these types of older cable, the insulation breaks down over time, resulting in cable failure. Typically, external moisture around the cable penetrates through the degraded polyethylene insulation, causing electrical tracking along voids and allowing contaminants to corrode the insulation. The corrosion patterns, which look like trees, are commonly referred to as "treeing." Treeing is a common cause of underground cable failure, particularly for XLPE cable. Heat from the electricity running through the cables which have "treed" contributes to thermal decomposition of polymers. This in turn can lead to the generation of combustible gases.

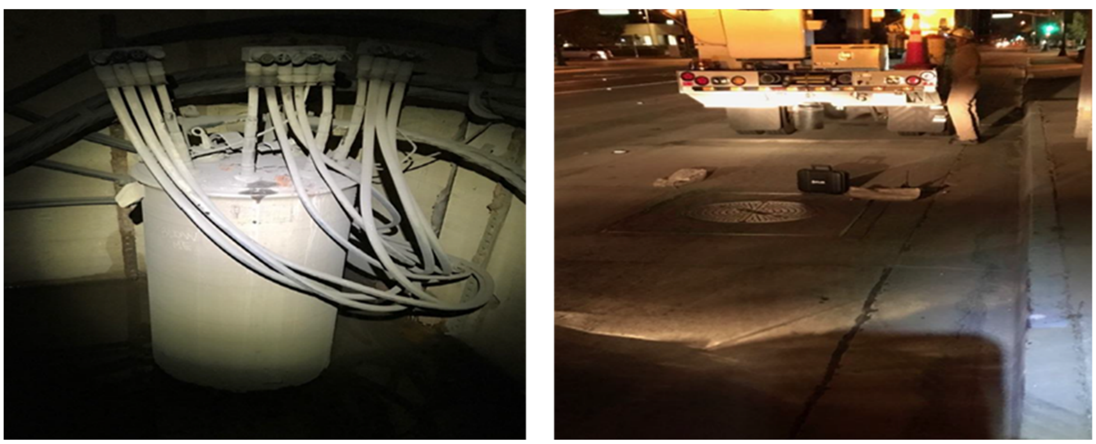
When an underground cable fails, electricity tracks through the insulation resulting in a fault. This fault condition causes an upstream protective device (such as a fuse, automatic recloser, or substation circuit breaker) to operate and de-energize power to all customers downstream of the protective device. This fault can also, concurrently, release a large amount of energy. In extreme cases, this release of fault energy can lead to violent outcomes, such as an explosion in underground structures. When cable components such as elbows, T-connectors, and splices fail, the resulting consequences can be very similar to the consequences of cable failures themselves. For this reason, SCE has combined cable and cable components together for this analysis.

2. D2 - Transformers

This driver category includes in-service failures of underground equipment known as BURD transformers, as defined earlier. Like all distribution transformers, BURD transformers step down voltage from primary voltage levels (typically 4 kV, 12 kV, 16 kV, and 33kV) to voltages utilized by end-use customers (i.e., 120/240 V). BURD transformers are designed for use in subsurface applications such as vaults, manholes and BURD enclosures. Based on 2017-2021 ODRM data, SCE's system experienced an average of 353 BURD transformer failures per year (approximately 17% of total annual observed UG Equipment Failures). Table II-3 above provides historical frequency of this driver category.

Figure II-5 below shows a typical BURD transformer installed within an underground vault on SCE's system.

Figure II-5
BURD Transformer (left) installed in an SCE underground structure (right)



BURD transformer failures can be catastrophic in nature due to various factors such as fault duty that the transformer experiences, the type of fault internal to the transformer (i.e. winding short, fuse failure), and the proximity to upstream fusing as well as the fusing type. To illustrate, Figure II-6 shows a picture of a catastrophically failed BURD transformer. In this picture, the top of the transformer shows significant damage caused when the transformer collided with the concrete vault ceiling. The transformer was launched upward into the vault ceiling when the core and coil were ejected out of the bottom of the transformer housing during the equipment failure.

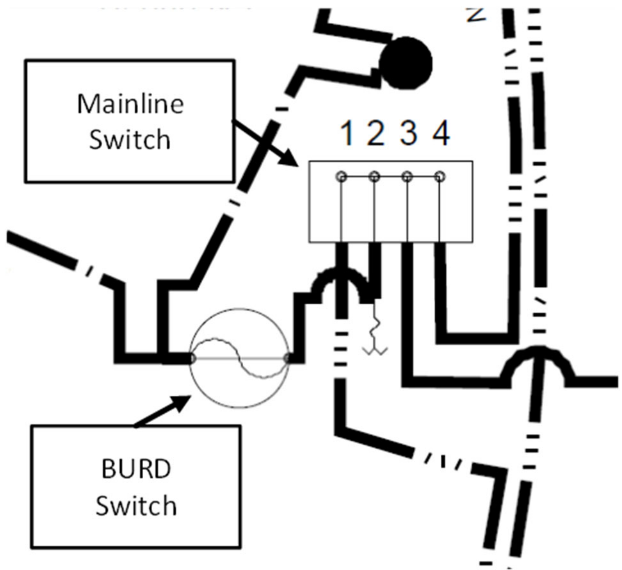
Figure II-6
D2 (BURD Transformer): Catastrophic Failure

3. **D3 - Switches**

This driver category includes the in-service failure of subsurface equipment known as switches. Similar to distribution cable, distribution switches will typically fit into one of two types – mainline switches and BURD switches. Mainline switches are typically used to divide mainline circuits into sections or load blocks. BURD switches are typically used to separate mainline and radial portions of a circuit.

Figure II-7 graphically represents a mainline switch and a BURD switch on a typical SCE underground distribution circuit. SCE has approximately 16,000 mainline switches installed on its underground system. These switches vary in design from oil and gas to vacuum and air insulated. These mainline switches are separate from the approximately 17,000 BURD switches installed on SCE's underground system.

Figure II-7
Illustration of Mainline Switch and BURD Switch



Historically, oil-filled mainline switches were a particular concern for SCE. When an oil-filled switch degrades over time, this degradation can lead to an increase in dissolved explosive gases within the switch oil. These dissolved gases increase the risk of explosion. Failures of oil-filled equipment can damage adjacent electrical equipment (e.g., cable, transformers, and other switches). While a large majority of oil-filled switches have been replaced, SCE continues to prioritize the replacement of oil-filled switches, along with appropriately addressing other switch types so that we holistically approach the risk across our service area.

Based on five years of historical data (2017-2021), SCE's system has experienced an average of 116 switch failures per year (approximately 5.6% of total annual observed underground Equipment Failures). Approximately 70% of the 116 failures are BURD switch failures, for a BURD switch annual failure rate of approximately 0.5% of the entire BURD switch population.

BURD switches can either be fused or non-fused, and are rated at 200 amps for radial load applications. Additionally, fused BURD switches function as an upstream protective device for local or smaller radial load blocks. The remaining 30% of these 116 failures are mainline switch failures, for a mainline switch annual failure rate of approximately 0.3% of the entire mainline switch population.

4. D4 - Others

This includes the failure of other underground equipment components, namely fuses, isolation devices, capacitor banks, and other miscellaneous equipment. Due to the relatively small number of occurrences of equipment failure among these types of equipment, they were grouped together for analytical purposes.

Based on 2017-2021 ODRM data, SCE's system has experienced an average of 81 failures per year for equipment that does not fit into driver categories D1 - D3 (approximately 3.9% of total annual observed UG Equipment Failures).

D. Triggering Event

The triggering event is the in-service failure of UG electrical equipment asset(s) within an SCE underground structure, which potentially causes substantial and uncontrolled release of energy from a vault or manhole. Based on 2017 - 2021 ODRM data, SCE is experiencing an average triggering event frequency of 2,083 UG Equipment Failures per year. Table II-3 above summarizes the historical annual triggering event frequency.

E. Outcomes and Consequences

1. O1 - Explosion

For this analysis, SCE uses the term "explosion" to refer to the uncontrolled release of energy from an underground vault or manhole caused by equipment failure on the distribution system. This outcome can result in displaced manhole covers, other flying debris, and/or significant damage to roadways or sidewalks. All of these items can pose a risk of serious injury or fatality to the public. For example, Figure II-8 shows the damage to an SCE manhole and a public street associated with a vault explosion triggered by a failed distribution cable (O1, D1).

Figure II-8
Illustration of Explosion Outcome (O1) due to Cable Driver (D1)

Based on SCE's Covered Pressure Relief and Restraint (CPRR) Event Tracker Data, SCE has observed a rate of approximately 20 explosion events per year in underground vaults or manholes. With a triggering event frequency of 2,083 equipment failures per year, this results in an outcome percentage of 1.3% of underground equipment failures that result in an explosion in an underground vault or manhole (O1). For the safety consequences associated with a vault explosion, SCE used CPUC reportable incidents resulting in serious injuries or fatalities to the public.[12] SCE used the data from ODRM to calculate the customer minutes of interruption (CMI) for underground equipment failure

[12] SCE believes that there is a possibility for a fatality to occur, and used SME judgement to estimate a fatality once every 30 years.

events. To estimate the financial consequences, SCE used internal work orders for priority one (P1) repair costs associated with the explosion events.[13]

2. O2 - Non-Explosion

The majority of underground equipment failures do not result in an explosion from a vault or manhole. For purposes of this analysis, these failure events are referred to as "non-explosion" events. In such instances, the system operates as designed, and the energy associated with these equipment failures does not exceed the system's capacity to contain or control it. Therefore, SCE did not model any safety consequences associated with this outcome. SCE used the data from ODRM to calculate the customer minutes of interruption (CMI) for each underground equipment failure event. To estimate the financial consequences, SCE used internal work orders for priority one (P1) repair costs associated with non-explosion events.[14]

Based on all available CPRR Event Tracker data, SCE has concluded that 98.7% of UG Equipment Failures result in non-explosion event outcomes (O2). This is equivalent to an expected value of approximately 2,062 non-explosion events per year throughout SCE's service territory.

F. Tranches

Underground equipment failure risks are disaggregated into tranches at the functional location (FLOC), equipment or segment levels, depending on the asset being evaluated. SCE focuses on addressing direct safety risks that result from an explosion; our approach is to either prevent equipment failures that can lead to an explosion, or prevent or lessen negative outcomes if an explosion event does occur. In Table II-4 below, we summarize the tranches utilized for underground equipment failure. In our workpapers, SCE provides risk spend efficiencies (RSEs) at the level of granularity described in Table II-4. For readability and presentation purposes in this chapter, SCE is presenting RSEs at the control and/or mitigation level.

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[13] SCE excluded certain repair order costs for explosion events that did not have an associated P1 notification, or were associated with storm incidents such that other repair costs were bundled with this work.

[14] Again, SCE excluded certain repair order costs for non-explosion events that did not have an associated P1 notification, or were associated with storm incidents such that other repair costs were bundled with this work.

Table II-4
Tranching Approach for Underground Equipment Failure

Risk	Tranche
Structure (CPRR)	per FLOC (e.g., vault, manhole)
Cable failure	per cable segment
Switch failure	per subsurface switch
Transformer failure	per subsurface transformer

For modeling purposes, SCE's prioritizes the mitigation for each equipment or structure from the highest risk to the lowest risk on the safety risk buydown curve. In practice, some adjustments to the prioritization may be required to levelize work across the territory.

G. <u>Related Factors</u>

For purposes of this discussion, SCE defines related factors as those factors that are not directly included in the risk modeling but can impact the driver frequency and the likelihood of certain outcomes. Some considerations are:

- **Changes in Operating Conditions** – Operating conditions such as high peak loading or exposure to fault conditions can change the risk profile of electrical equipment by increasing their effective age. Higher effective age is correlated with higher probability of failure. Unforeseen changes in operating conditions could have an impact on the overall risk profile for underground equipment.
- **Changes in Population Density** – Population density factors into the probability of a negative outcome. If the population density changes, it could alter the risk profile of certain areas. For example, the state of California is already seeing early trends that some populations are moving from city centers to more rural counties. If these trends persist, there could be an increase in the risk profile of previously lower-population areas. Also, California

has recently passed laws[15] to increase available housing units by allowing for more accessory dwelling units (ADUs), as well as subdividing lots and replacing single family units with multi-dwelling units. The newer laws could result in existing low-density residential areas transforming into medium- or high-density residential areas.

III.

COMPLIANCE

SCE has existing compliance programs and processes in place to mitigate this risk. These compliance activities are not modeled in this risk analysis, but are discussed below.

A. CM1 - Underground Detail Inspections (UDI) and Underground Preventive Maintenance (UPM)

SCE's Underground Detail Inspections (UDI) and Underground Preventive Maintenance (UPM) are activities included in SCE's Distribution Inspection and Maintenance Program (DIMP). The goal of DIMP is to meet the requirements of General Orders (GO) 95, 128, and 165 in a way that: (1) follows sound maintenance practices; (2) enhances public and worker safety and maintains system reliability; and (3) delivers overall greater safety value for each dollar we spend by allowing SCE to focus its limited resources on higher-priority risks.

DIMP enables us to prioritize work based on the condition of each facility or piece of equipment and how it potentially impacts safety and reliability. SCE considers various factors, including the facility or equipment itself, loading, location, accessibility, climate, and direct or potential impact on safety or reliability. DIMP enables SCE to prioritize resources effectively and efficiently to remediate conditions that potentially pose higher risks. This approach follows the Commission's direction under GO 95 and a memorandum of understanding between SCE and the CPUC's Safety and Enforcement Division.

DIMP has three maintenance priority levels. During inspections, SCE inspectors identify and rate conditions observed, in consideration of the factors discussed previously. Highest priority issues requiring immediate action are assigned Priority 1 (P1). Priority 2 (P2), which is the next highest

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[15] 2017 - Senate Bill (SB) 1069, Assembly Bill (AB) 2299 AB 2409; 2020 - AB 881, AB 670, SB 13, AB 68; 2021 - SB 9.

priority, includes issues do not require immediate action, but require corrective action within a specified time period. Priority 1 and Priority 2 issues may be fully repaired, or temporarily repaired and reclassified as a lower priority item. Priority 3 (P3) items are lower-priority issues that involve little or no safety or reliability risk. While Priority 3 issues do not require immediate action, they do require corrective action within 60 months.[16] These actions may include re-inspecting, reassessing, or repairing.

IV.

CONTROLS

SCE has programs and processes in place today that serve to reduce the frequency of this risk event from occurring, or the impacts of the risk event should it occur. These activities are summarized in Table IV-5, and discussed in more detail below.

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[16] *See* D.18-05-042 for the Commission action to amend Rule 18 of GO 95, and mandate that Priority 3 maintenance items be corrected within 60 months (effective June 30, 2019).

Table IV-5
Inventory of Underground Equipment Failure Controls[17]

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
C1	Worst Circuit Rehabilitation (WCR)	D1	-	-	Yes	All
C2	Cable Replacement Programs (Cable-In-Conduit)	D1			Yes	All
C3	Underground Switch Replacement Program	D3	-	-	Yes	All
C4	Cover Pressure Relief and Restraint (CPPR) Program	-	O1	Safety	Yes	All

A. C1 – Worst Circuit Rehabilitation (WCR)

1. Description

SCE's Worst Circuit Rehabilitation (WCR) Program is broken out into two activities. The first addresses the problems of deteriorating underground mainline cable, and mitigates the negative consequences of in-service cable failures on system reliability and associated safety risks. The second WCR activity is a regulatory requirement[18] which focuses on circuits that disproportionately contribute to system reliability; here, we must rank circuits based on three years of historical reliability performance data and target the worst performing 1% of circuits for detailed consideration. Circuit rehabilitation typically involves replacing aging mainline cable on each circuit. The WCR

[17] SCE has excluded the Worst Performing Circuit Program (WPC) which represents a sub-part of the WCR Program. The WPC is a compliance requirement, pursuant to D.16-01-008. Additionally, SCE also does not include the Underground Structure Replacement and Shoring activity. We agree with the Commission's view regarding the "critical safety risk" (see D. 19-08-013) for Underground Structure Replacements and Shoring, However, SCE has no reported instances of structural failure resulting or contributing to an underground equipment failure. Based on the modelling approach to assessing risk drivers, underground structure failure as a driver has no input, or an input of 0 events as a risk driver. A zero RSE distorts the Commission's stated guidance and inaccurately suggests that this program is not important for safety purposes. SCE currently inspects and replaces underground structures under the Underground Distribution Inspection activity (UDI) and Deteriorated Vault and Maintenance Program (DVMP), respectively. Underground structures are proactively inspected, and conditions are assessed and scored according to their structural integrity and prioritized for remediation based on the observed level of deterioration.

[18] D.16-01-008.

Program also adds circuit enhancements such as automation, automatic re-closers, branch line fuses, and fault indicators.

The current deployment plan for this program includes replacing approximately 965 conductor miles from 2025 through 2028. These levels are subject to change based on year-to-year scoping details, resource constraints, and other items.

2. Drivers Impacted

The WCR Program addresses Cable and Cable Accessories (D1) drivers. The WCR Program replaces aging mainline cable and cable accessories prior to failure. SCE's ODRM indicates that approximately 42% of cable-related failures are on mainline cable.

3. Outcomes or Consequences Impacted

The WCR program is not modeled to impact the outcomes or consequences.

B. C2 – Cable Replacement Program (Cable-In-Conduit)

1. Description

The CIC Replacement Program replaces cables which have failed testing or cannot be remediated. CIC is a cable type that is factory pre-installed in conduit. This allows for an efficient one-step installation process, as opposed to installing of duct and cable separately. SCE no longer installs CIC for new installations, due to challenges with maintenance. In some instances, the conduit around the cable has deteriorated, which blunts the ability to remove and reinstall cable through the existing conduit. Since the cable is buried, the condition of the conduit is not known until replacement is attempted. Due to the difficulties that can arise in replacing CIC, SCE performs testing or rejuvenation of CIC segments.[19] Segments that have failed testing or cannot be rejuvenated are mitigated by the CIC Replacement Program.

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[19] Cable rejuvenation involves injecting a silicone fluid into the strands of the cable. The fluid migrates into the conductor shield and insulation, modifying the insulation's chemistry and extending the cable life. In certain situations, rejuvenation cannot be successfully performed. In particular, rejuvenation of mainline cable is not feasible, since mainline injection of primary cable will impact a larger number of customers than scheduled outages for CIC injection on circuit radials. At this time, SCE does not possess sufficient data to conclude that mainline cable injection would be cost-effective.

The current deployment plan for this control includes replacing approximately 735 conductor miles of cable from 2025 - 2028. These levels are subject to change based on year-to-year scoping details, resource constraints, and other items.

2. Drivers Impacted

The CIC Replacement Programs impacts Driver D1 (Cable and Cable Accessories). This program either extends the life of aging cable or replaces cable and cable accessories prior to failure, reducing the likelihood of a near-term failure.

3. Outcomes or Consequences Impacted

The CIC Replacement Program will not directly impact outcomes or consequences should a failure occur.

C. C3 – Underground Switch Replacement Program

1. Description

SCE's Underground (UG) Switch Replacement Program replaces switches in underground structures which are approaching the end of their service lives and pose a threat to both system reliability and public/employee safety. This program has been replacing aging mainline oil-filled switches every year since at least 2005. SCE plans to continue its program of preemptively replacing subsurface switches. In the recent past, program efforts have focused primarily on replacing mainline oil-filled switches. Going forward, SCE's program will be inclusive of all switches (not just oil-filled), and prioritized based on risk. This is expected to result in more radial switch replacements, because of the greater failure rate of BURD switches and the relatively older age of the existing BURD switch population.

The current deployment plan for this control includes replacing approximately 224 switches from 2025 - 2028. These levels are subject to change based on year-to-year scoping details, resource constraints, and other factors.

2. Drivers Impacted

The Underground Switch Replacement Program impacts D3 (Switches). The program preemptively replaces both mainline and radial subsurface switches prior to failure.

3. Outcomes or Consequences Impacted

The Underground Switch Replacement Program will not directly impact outcomes or consequences should a failure occur.

D. C4 – Cover Pressure Relief and Restraint (CPRR) Program

1. Description

The CPRR Program is a control program which deploys a new vault lid technology on SCE's system. Standard unrestrained vault and manhole covers can become projectiles during explosion events. This control involves replacing standard vault and manhole covers with newer-technology covers that are designed to both relieve built-up pressure and restrain the cover during explosion events.

SCE has been deploying CPRR lids as a proactive program since late 2018. We have built up experience in efficiently deploying CPRR lids. For the 2025-2028 cycle, the CPRR Program target is 330 manholes and vaults per year, for a total installation count of approximately 1,320. Installations are targeted based on location-specific risk factors, such as population density, proximity to schools or hospitals and/or other areas of congregation, as well as the nature and type of electrical equipment in terms of probability for failure in the associated underground structures -- this includes cables, transformers, and BURD switches.

SCE is investigating expanding the deployment of CPRR lids to additional structure types, including Surface Operable Equipment/Customer Service Transformer structures.
These structures are smaller than vaults manholes, but still contain cables and transformers.

2. Drivers Impacted

The CPRR Program is focused on reducing the impact of associated consequences. It is not designed to reduce any of the identified drivers.

3. Outcomes or Consequences Impacted

The CPRR Program is intended to reduce the safety consequences associated with O1 (Explosion from a Vault or Manhole). The CPRR Program involves deploying new vault lid technology that decreases the likelihood of serious injury or fatality due to a vault explosion event.

V.

MITIGATIONS

In addition to compliance and control activities mentioned above, SCE has examined whether additional mitigations can reasonably be added to the suite of existing activities that address this risk. These mitigations are summarized in Table V-6, and discussed in more detail thereafter.

On an overall basis, SCE's proposed plan and alternatives do not fundamentally differ from what was proposed in the 2018 RAMP. SCE's current measures to address this risk are well-established and industry-accepted.

Moreover, since the time that SCE filed its 2018 RAMP, SCE has necessarily focused its efforts and allocate its resources to a significant degree on addressing and mitigating the emergent Wildfire risk. As a result, we have not instituted major new programs or projects that specifically are targeted at enhancing our mitigation of Underground Equipment Failure risk. SCE has engaged in limited assessments of newer technologies, and has considered whether such technologies would be prudent to implement at this time. Based on these discrete efforts, SCE has not found that any substantial new technology is sufficiently mature and widely-used so that it can be readily and reliably implemented using the scarce resources that are available and are not currently devoted to mitigating the Wildfire threat to our customers and the communities we serve.

If there is an update regarding mitigations and potential alternatives, SCE will provide the update when SCE files its TY 2025 GRC application in May 2023.

Table V-6
List of Underground Equipment Failure Mitigations

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
M1	BURD Transformer Replacement	D2	-	-	Yes	Alternative Plan #1
M2	Fault Indicator	D1	-	-	No	Alternative Plan #2

A. M1 – BURD Transformer Replacement

1. Description

This is a mitigation program that entails preemptively replacing BURD transformers based on the safety risk profile of specific locations. In this risk analysis, BURD transformer failures are the second largest driver, with 328 transformer failure events per year at current rates. This amounts to nearly one BURD transformer failure per day in the SCE system.

SCE has approximately 82,000 BURD transformers in its inventory today. This mitigation was modeled as replacing only 50 BURD transformers per year for years 2025-2028 with like-for-like replacements. This assumed replacement rate of only 0.1% of the population each year was selected as an initial replacement rate. This approach would give SCE an opportunity to learn from and refine transformer risk modeling before launching a bigger program. It will also let us assess resourcing needs in an orderly fashion, to help us make sure that the bulk of the transformers can be deployed in an efficient manner at scale.

2. Drivers Impacted

Implementing a new BURD Transformer Replacement Program would directly address D2 - Transformers). This program replaces aging BURD transformers prior to failure.

3. Outcomes or Consequences Impacted

A BURD Transformer Replacement Program will not directly impact outcomes or consequences should a failure occur.

B. M2 – Fault Indicator

1. Description

Fault indicators provide a visual indication, usually in the form of a light, when fault current is present. When determining the location of an underground fault, a troubleman can use these fault indicators to more precisely determine the location of the faulted equipment or cable, and isolate the fault by operating the closest switching devices. The existing method for locating failed sections of underground cable require operators and troubleman to progressively isolate and test segments of the circuit. During testing, the isolated underground cable and equipment is re-energized, with the potential risk for additional arcing or catastrophic failure at the damaged location. Fault indicator installations are targeted at the individual circuits, based upon the weighted average risk consequence scores of all structures on a given circuit or segment.

2. Drivers Impacted

Fault indicators on underground circuits would affect all drivers, cable/component failures, transformer failures, switch failures, and miscellaneous equipment failures. The mitigation would limit the number of times those assets were subjected to fault current. It should be noted that fault indicators will not affect the initial fault and possible explosion. Fault indicators may prevent further failures and resulting explosions during fault location and service restoration; this is due to better fault location, reducing the number of times that faults are tested into. Fault indicators would also provide the benefit of extending the life of assets on the affected circuit, by limiting the number of times equipment is exposed to fault current due to circuit testing during service restoration.

3. Outcomes or Consequences Impacted

The Fault Indicator program will not impact outcomes or consequences in the risk model.

VI.

FOUNDATIONAL ACTIVITIES

Through the RAMP process, SCE did not identify any activities that are considered foundational that support any of the Proposed Plan controls. SCE will continue to investigate whether any work activities should be considered foundational prior to filing our TY 2025 GRC.

VII.`

PROPOSED PLAN

SCE has evaluated the controls and mitigations identified above, and we have developed a Proposed Plan for mitigating the Underground Equipment Failure risk. The elements of this Proposed Plan are shown in Table VII-7 below. The pre- and post- LoRE, CoRE and risk scores for the proposed plan is summarized by tranche below in Table VII-8.

Table VII-7
Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[20]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1	Worst Circuit Rehabilitation (WCR)	-	$531.62	92
C2	Cable Replacement Program (Cable-In-Conduit)	-	$263.94	53
C3	Underground Switch Replacement Program	-	$13.80	31
C4	Cover Pressure Relief and Restraint (CPPR) Program	-	$34.70	114
Total		**-**	**$844.05**	**-**

Table VII-8
Pre- and Post- LoRE, CoRE and Risk Scores[21]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Underground Equipment Failure	1,955	0.0010	1.96	1,820	0.0009	1.71

[20] Please refer to WP. Ch. 2 – RSE Summaries and WP Ch. 6 – Underground Equipment Failure Financial Forecasts.

[21] Please refer to WP. Ch. 2 – RSE Summaries.

1. Overview

The Proposed Plan continues to deploy existing controls at specified levels over the RAMP period. This involves executing the WCR (C1), CIC (C2), UG switch replacement (C3), and CPRR programs (C4). The Proposed Plan continues deploying proven distribution infrastructure replacement programs that help address this risk. The Proposed Plan's controls provide a balanced approach of aiming to reduce the frequency of equipment failures, and lessen the potential safety consequences of an underground explosion event. The WCR (C1), CIC (C2) and UG switch replacement (C3) address two of the drivers that constitute approximately 80% of the total risk driver frequency. As indicated above, the CPRR Program involves deploying vault lid technology that decreases the likelihood of serious injury or fatality due to a vault explosion event.

2. Execution Feasibility

SCE has been executing these programs for multiple years. Accordingly, we are confident in our ability to continue to execute these infrastructure replacement programs during the upcoming RAMP period.

3. Affordability

This Proposed Plan is the least expensive mitigation plan that SCE considered for this RAMP filing. It continues to deploy proven distribution infrastructure replacement programs.

4. Other Considerations

Because this Proposed Plan consists of existing and established controls, and SCE has gained experience executing CPRR equipment since the program commenced, we currently do not anticipate any other substantial challenges in executing this plan.

VIII.

ALTERNATIVE PLANS

A. Alternative Plan #1

SCE has evaluated two alternative plans to mitigate the Underground Equipment Failure risk. Alternative Plan #1 is shown in Table VIII-9. The pre- and post- LoRE, CoRE and risk scores for Alternative Plan #1 are summarized by tranche below in Table VIII-10.

Table VIII-9
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[22]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1	Worst Circuit Rehabilitation (WCR)	-	$531.6	92
C2	Cable Replacement Program (Cable-In-Conduit)	-	$263.9	53
C3	Underground Switch Replacement Program	-	$13.8	31
C4	Cover Pressure Relief and Restraint (CPPR) Program	-	$34.7	114
M1	BURD Transformer Replacements	-	$4.4	50
Total		**-**	**$848.5**	**-**

Table VIII-10
Pre- and Post- LoRE, CoRE and Risk Scores[23]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Underground Equipment Failure	1,955	0.0010	1.96	1,820	0.0009	1.71

1. Overview

Alternative Plan #1 includes all existing controls as described in the Proposed Plan (C1, C2, C3, C4). Alternative Plan #1 adds a new infrastructure replacement program for BURD transformers (M1) as a preventative mitigation. Under BURD Transformer Replacements (M1), 50 BURD Transformers would be replaced annually, with new equipment installed on a like-for-like basis.

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22 Please refer to WP. Ch. 2 – RSE Summaries and WP Ch. 6 – Underground Equipment Failure Financial Forecasts.

23 Please refer to WP. Ch. 2 – RSE Summaries.

Equipment would be targeted for replacement based on predictive modelling for locations and assets with the highest probability and consequence of failure. This mitigation is designed to address the second-largest driver of underground equipment failures – BURD transformers (D2). D2 is not directly addressed by any existing control within SCE's Proposed Plan.

Since the 2018 RAMP filing, SCE has further investigated the inclusion of a proactive BURD transformer replacement program. In 2020, SCE conducted a pilot to test the effectiveness of predictive modelling in identifying BURD transformers that need replacement, in order to help gauge the value of this activity in preventing equipment failure or explosion events. The pilot program replaced 44 BURD transformers based on the predictive modeling. The transformers we removed were disassembled and inspected to determine the likelihood of failure based upon the condition of the equipment.

Our examination of those transformers yielded inconclusive and possibly negative results. SCE did not find that the transformers identified by the model appeared to be at a higher risk of failure. Therefore, based on what we know currently, we have tentatively concluded that the mitigation approach under M1 does not necessarily appear to be effective at preventing UEF. We drew our conclusion based on the low correlation between (a) the BURD transformers that the model predicted would be high-risk, and (b) our detailed inspection of the actual condition of those transformers.

2. <u>Execution Feasibility</u>

As discussed above, we conducted a pilot to examine the effectiveness and accuracy of predictive modelling in mitigating the failure of BURD transformers. As part of that pilot, we replaced 44 BURD transformers in one year. The BURD Transformer Replacement program under Alternative Plan #1 contemplates 50 BURD transformer replacements per year. SCE believes that this pace of execution would be feasible, based on successfully replacing nearly 50 transformers in one year to carry out the pilot program.

3. Affordability

The cost for Alternative Plan #1 is approximately $4.4 Million more than the Proposed Plan over 2025-2028. This relatively small cost increase over the Proposed Plan was not a major factor in our decision to not pursue the BURD Replacement Program (M1) at this time.

4. Other Considerations

BURD transformers have a relatively low incidence of failure. Predictive replacements based upon the model or other analytics have not been shown to be effective in avoiding BURD transformer failure. If we apply the current modelling we used for the pilot to historical asset data-sets, it appears we would not have consistently identified those transformers which historically experienced failure. Currently, underground inspection programs are SCE's best approach to proactively identify and replace BURD transformers which are showing indicators of failure.

B. Alternative Plan #2

Alternative Plan #2 is shown in Table VIII-11. The pre- and post- LoRE, CoRE and risk scores for Alternative Plan #2 are summarized by tranche below in Table VIII-12.

Table VIII-11
Alternative Plan #2 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[24]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1	Worst Circuit Rehabilitation (WCR)	-	$531.62	92
C2	Cable Replacement Program (Cable-In-Conduit)	-	$263.94	53
C3	Underground Switch Replacement Program	-	$13.80	31
C4	Cover Pressure Relief and Restraint (CPPR) Program	-	$34.70	114
M2	Fault Indicator		$0.64	-
Total		**-**	**$844.69**	**-**

Table VIII-12
Pre- and Post- LoRE, CoRE and Risk Scores[25]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Underground Equipment Failure	1,955	0.0010	1.96	1,820	0.0009	1.71

1. Overview

This Alternative Plan #2 includes all existing controls as described in the Proposed Plan (C1, C2, C3, C4). Alternative Plan #2 includes a new mitigation activity (M2). This mitigation involves deploying underground fault indicators on circuits at high-risk locations. As described in the mitigation

[24] Please refer to WP. Ch. 2 – RSE Summaries and WP Ch. 6 – Underground Equipment Failure Financial Forecasts.

[25] Please refer to WP. Ch. 2 – RSE Summaries.

section above, additional fault indicators would support troublemen in locating faults, requiring fewer test operations that could lead to equipment failures.

The effectiveness of this mitigation is dependent upon being able to sectionalize a circuit into as small a load block (i.e., customer count) as possible. Therefore, installations would need to target multiple structures of a circuit with high consequence locations. In a practical sense, the benefit provided by fault indicators depends on a piece of equipment actually failing. The fault indicator does give the benefit of possibly preventing additional equipment issues due to circuit tests. However, our initial working assumption is that the additional safety benefits of installing fault indicators would be relatively low.

While SCE has experienced events where a second piece of equipment fails during the course of locating and isolating an underground fault, a second equipment failure appears to occur in a small minority of cases. Further, in order for the fault indicator to come into play in providing critical safety benefits in this situation, the failure of the second piece of equipment would need to result in some type of explosion event. Historically, this result has been recorded at only 1% likelihood.

This mitigation is not necessarily designed to prevent the initial piece of equipment from failing, (as depicted in the bowtie in Figure II-3). Thus, estimating the mitigation effectiveness in reducing potential consequences as a result of secondary equipment failure is difficult, given the very infrequent number of past events in which this has occurred. Therefore, SCE was unable to calculate a reasonable RSE for this mitigation.

2. **Execution Feasibility**

This alternative is feasible from the standpoint of basic project execution. This alternative involves SCE installing fault indicators on underground equipment. SCE already installs fault indictors on underground equipment for reliability purposes, and could easily adapt installing fault indicators as a safety practice.

3. **Affordability**

While underground fault indicators are relatively inexpensive to purchase and install, as noted above, the effectiveness of this mitigation depends upon being able to sectionalize a circuit to as small a load block (i.e., customer count) as possible. Therefore, installations would need to target multiple structures of a circuit with high consequence locations. The need for multiple installations per circuit, combined with the estimated low public safety benefits, meant that on balance we felt that it was not optimal to move forward with this program at this time.

4. Other Considerations

While fault indicators have a relatively low safety benefit in and of themselves, the upshot of recurring fault could be a subsequent equipment failure that results in an explosion.
Fault indicators for underground equipment offer promising reliability benefits because they allow crews to more quickly identify the faulted section, isolate it, and restore service to customers that are actually unaffected by the specific fault.

IX.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

In connection with public safety, SCE has been implementing the CPRR program to reduce the risk of a manhole lid displacing in the event of a distribution vault explosion. CPRR has been effective, and has prevented at least one manhole lid projectile event when a vault explosion occurred. SCE has been investigating technologies involving sensors to assist with underground equipment fault detection failures; however, a pilot is not underway currently. Finally, an Underground Remote Fault Indicator (RFI) is available for underground equipment such as switches for troubleshooting purposes, in order to reduce the restoration time in the event of a customer outage.

Historically, the documentation of event outcomes, field conditions at the time of failure and asset data were captured in discrete locations, and did not provide the level of detail necessary to develop accurate models to predict or respond to possible indicators of a near-term equipment failure event. SCE identified that reliable predictive models for underground equipment failures required improvements in the techniques and granularity of data captured.

To address this requirement, SCE's Failure Analysis Team developed a pilot process to retroactively sweep repair orders back to 2016, searching for indicators of explosion, fire or smoke

outcomes documented during underground equipment repairs. The pilot has since matured to review of all incoming repair orders to identify events consistent with an explosion or fire outcome.
Identified events associated with either a fire or explosion are then investigated by the Failure Analysis team. Fire outcomes are investigated through SCE's Fire Incident Preliminary Analysis process.
For explosion events, SCE conducts a follow-up investigation to ascertain the equipment or component source of the failure, field conditions, inspection history and other potential contributing factors.

The Failure Analysis team is concurrently conducting an analysis of front-end inspection driven repairs within the Failure Modes Effects and Analysis (FMEA) database. The database tracks and monitors existing trends from P1 and P2 notifications derived from SCE's Underground Detailed Inspection (UDI) program. Based on the inspection-identified repairs, data regarding asset type, age, location, and other collected data points are considered to identify trends. While the current data and trends are not conclusive for actionable mitigations or strategies, SCE intends to continue to pursue these efforts to improve the existing data capture and modelling capabilities. In the future, SCE anticipates improved reliability of predictive models, as more inputs are captured and the sample size increases.

B. Data Collection and Availability

Having accurate data is crucial for effectively modeling risk and determining scope. As indicated in our 2018 RAMP report, SCE experienced challenges with data availability on the consequence side of the underground equipment failure bowtie.[26] As discussed above, the CPRR Event Tracker has made it easier to identify the outcome of an underground equipment failure event.

C. Performance Metrics

SCE tracks a significant amount of data related to underground equipment failure events. Table IX-13 below summarizes some key performance metrics related to underground equipment failure events; however, this is not an exhaustive list. The table also indicates whether any of these metrics are

[26] *See* SCE 2018 RAMP Report, Chapter 11 – Underground Equipment p. 11-30.

included in SCE's annual Safety Performance Metrics (SPM) report[27] and if there is any relationship to the RAMP bowtie and/or risk analysis.

Table IX-13
List of Underground Equipment Failure Performance Metrics

Metric	Leading / Lagging Indicator	Included in SPM Report	Metric Directly Included in Risk Bowtie	Bowtie Element	Description / Definition
Quantity of Underground Explosion Events	Lagging	No	Yes	This informs the explosion event outcome	The number of events with an uncontrolled release of energy from an underground vault or manhole caused by equipment failure on the distribution system
Quantity of Underground Equipment Failure Events	Lagging	Yes	Yes	This directly informs the triggering event frequency of the risk bowtie.	The number of primary distribution underground electrical equipment failures.
Missed Inspections and Patrols for Underground Circuits	Leading	Yes	No	Not direcly included in risk analysis or risk bowtie	The annual number of overhead electric structures that did not comply with the inspection frequency requirements divided by total number of overhead electric structures with inspections due in the past calendar year.
GO-95 Corrective Actions Completed On Time	Leading	Yes	No	Not direcly included in risk analysis or risk bowtie	The number of Priority Level 2 notifications that were completed on time divided by the total number of Priority Level 2 notifications that were due in the calendar year. Consistent with GO 95 Rule 18 provisions, the proposed metric should exclude notifications that qualify for extensions under reasonable circumstances.
Outage minutes due to underground failure events	Lagging	No	Yes	Informs the reliability consequence of a underground failure event	The number of customer minutes of interruption per undergound equipment failure event

Additionally, SCE proposes to track the effectiveness of executing programs by comparing actual infrastructure replacement counts to planned amounts, including:[28]

- Miles of WCR and CIC replaced
- Number of oil transformers replaced
- Number of vault lids retrofitted
- Number of BURD transformers replaced (if applicable)

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[27] This is based on the updated list of SPMs from D.21-11-009, Appendix B.

[28] SCE also reports out on the authorized and recorded annual spending amounts and work units for WCR, CIC, UG Switches, and CPPR in our annual Risk Spending Accountability Reports (RSAR).

X.

ADDRESSING PARTY FEEDBACK

SCE received two recommendations from parties in our 2018 RAMP relating to the Underground Equipment Failure RAMP chapter. SCE directly addressed these items in our Test Year 2021 GRC Track 1 prepared testimony.[29] We would like to provide a further update in our 2022 RAMP regarding how we are addressing one of the recommendations from our 2018 RAMP.

In SCE's 2018 RAMP proceedings, Cal Advocates had recommended that SCE show specific details on the locations of the proposed mitigations, and outline how those mitigations would be implemented in our Test Year 2021 GRC.[30] As part of our 2022 RAMP Report, SCE is providing asset level RSEs (as described in section II.F) on the assets that we currently expect to be mitigated from years 2022 – 2028.

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[29] SCE addressed Safety Enforcement Division's recommendations in our direct testimony in A.19-08-013, and then addressed comments from Cal Advocates and The Utility Reform Network in supplemental Exhibit SCE-11, titled "Supplemental Testimony on Risk-Informed Strategy & Business Plan."

[30] *See* I.18-11-016; Comments of The Public Advocates Office on November 2018 Submission of Southern California Edison Company's Risk Assessment and Mitigation Phase, p. 31.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Cyber Attack

Chapter 7

Rosemead CA
May 13, 2022

Chapter 7: Cyber Attack

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I.

EXECUTIVE SUMMARY

A. Risk Overview

In this chapter, we evaluate the risk to SCE, our electric system, and the customers and communities we serve if a cyber attack compromises SCE system controls. SCE identified and quantified the potential safety, reliability, and financial consequences resulting from this risk.

SCE's bowtie structure for this cyber attack risk has identified several options to mitigate the risk. We present a Proposed Plan that balances risk mitigation, execution feasibility, and cost efficiency. SCE's Proposed Plan of controls leverages the success of existing and ongoing cyber security programs, and adds enhanced capabilities that will help maintain our defenses amidst the persistent and growing threat of cyber attack.

Cyber security presents an ever-evolving challenge to SCE. The threat of cyber attacks is growing; attacks are continually becoming more frequent and more sophisticated. Our grid is evolving and incorporating communicating and operating technology that enables us to respond faster, operate our system more efficiently and reliably, and incorporate distributed energy resources at a greater level. But more reliance on advanced technology to operate and communicate necessarily increases risk of cyber attack, and greater potential consequences if a cyber attack is successful. State and federal government agencies are increasingly supporting cyber security, and in recent years these agencies have gained a more comprehensive understanding of how and when cyber attacks may occur. That support springs from the growth in cyber attack risks. SCE will need to enhance its capabilities to address this.

SCE identified a number of controls and mitigation plans to address these risks and threats.[1]

This chapter evaluates six controls:

- Perimeter Defense (C1): This includes activities that provide the first line of defense against cyber attacks. It is the outer layer of protection for our defense-in-depth approach to cyber security.

[1] C = Control. This is an activity performed prior to or during 2022 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report and are addressed in Section III.

- Interior Defense (C2): This includes protection controls securing SCE's internal business systems from unauthorized users, devices, and software.
- Data Protection (C3): This includes activities to safeguard the computing environment housing SCE's core information.
- SCADA Cyber security (C4): This includes risk-reduction methods specifically tailored for SCE's Supervisory Control and Data Acquisition (SCADA) systems.
- Grid Mod Cyber security (C5): This includes security and data protection activities for all new infrastructure and application assets being added through SCE's Grid Modernization program.

SCE has developed three risk mitigation plans:

- The Proposed Plan continues existing programs (C1, C2, C3, C4, & C5), and strikes a reasonable balance between cost and risk reduction.
- Alternative Plan #1 continues existing programs (C1, C2, C3, C4, & C5), with reductions in overall scope and cost resulting in lower mitigation effectiveness.
- Alternative Plan #2 continues existing programs (C1, C2, C3, C4, & C5), with increases in overall scope and cost resulting. It is the costliest of the three mitigation plans.

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Cyber Attack based on the proposed plan discussed below.[2]

At the outset, it is important to outline certain key limitations/challenges that SCE observed while calculating the risk spend efficiencies (RSEs) for Cyber Attack risk mitigations. The RSE modeling approach includes various factors such as incident rate of occurrence, mitigation effectiveness, severity of outcome, cost of outcome, and consequences. Because SCE was required to calculate RSEs

[2] LoRE – likelihood of risk event. CoRE – consequence of risk event. Risk Score is the product of the LoRE and CoRE. For additional information on the risk modeling methodology refer to Chapter 2 – Risk Model and Methodology.

at a tranche level, the "divided-up" RSEs do not reflect the true nature and complexity of integrated "system-of-systems" assets, networks, and defense-in-depth cyber security strategies.

For example, the majority of Operational Technology[3] / Grid System attack scenarios would involve an attacker leveraging IT or business network infrastructure as a conduit to OT / Grid Systems. As such, IT / business network cyber security controls have a potentially significant secondary benefit in preventing OT / Grid System attacks under some circumstances. However, by isolating systems and assets for the purpose of risk tranching, the interconnected and synergistic risk reduction benefits of a defense-in-depth cyber security approach are lost.

The importance of building and assessing cyber security in a combined rather than isolated manner has been recognized by authorities on standards for cyber security. For example, the National Institute of Standards and Technology (NIST), which is an arm of the U.S. Department of Commerce, has promulgated and utilized the following definition for defense-in-depth: "The application of **multiple countermeasures in a layered or stepwise manner to achieve security objectives**. The methodology involves layering heterogeneous security technologies in the common attack vectors to ensure **that attacks missed by one technology are caught by another**."[4] Thus, the different cyber security mitigations do not just interconnect. They cover for each other, so that in NIST's words, "attacks missed by one technology are caught by another."

Moreover, the Cybersecurity and Infrastructure Security Agency (CISA), part of the Department of Homeland Security (DHS), has published guidance recommending the use of defense-in-depth for organizations with OT environments, because it "increases the difficulty to access the control system."[5] CISA's predecessor organization, the Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) also recommended the use of a defense-in-depth strategy for organizations that are

[3] Operational Technology is referred to as OT in this chapter.

[4] *See, e.g.*, NISTIR 8183, *citing* ISA/IEC 62443 (emphasis added).

[5] https://www.cisa.gov/sites/default/files/publications/layering-network-security-segmentation_infographic_508_0.pdf.

considered critical infrastructure, such as electric utilities.[6] Additionally, the National Security Agency (NSA) within the U.S. Department of Defense (DoD) has published a draft technical report containing guidance on network architecture using defense-in-depth to help secure environments.[7] Defense-in-depth is also included in the U.S. Department of Energy (DOE) Cybersecurity Capability Maturity Model (C2M2) under the Cybersecurity Architecture domain.[8] This domain is assessed to create a maturity indicator level (MIL) based on an organization's advancement towards incorporating cybersecurity into their IT and OT architecture. SCE uses the C2M2 as a data point to track progress for overall IT and OT cybersecurity.

To give a practical analogy here, imagine a modern automobile as being akin to a cyber security program. The performance and capability of the automobile is the result of interconnected system components: engine, transmission, suspension, brakes, airbags, as well as electronic and computer control systems for engine performance, traction control, anti-lock brakes, etc. There are key performance indicators for the entire system, such as fuel mileage, safety rating, and acceleration. And there is a direct correlation between the relationship among the interconnected system components on one end, and the key performance indicators on the other end. While engine horsepower is strongly correlated to acceleration, the overall weight of all vehicle components secondarily impacts acceleration, braking distance, fuel mileage, etc. And of course, many components working together add up to the safety rating.

The interconnection between Cyber Attack mitigations is an even stronger one, because the mitigations not only work together, but pursuant to defense-in-depth, they *cover for* each other, as discussed above.

The approach of having to tranche cyber security risks, controls, mitigations, and estimated spending is akin to analyzing vehicle components and their primary contributions to vehicle

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[6] https://www.cisa.gov/uscert/sites/default/files/recommended_practices/NCCIC_ICS-CERT_Defense_in_Depth_2016_S508C.pdf.

[7] https://media.defense.gov/2022/Mar/01/2002947139/-1/-1/0/CTR_NSA_NETWORK_INFRASTRUCTURE_SECURITY_GUIDANCE_20220301.PDF.

[8] https://www.energy.gov/sites/default/files/2021-07/C2M2%20Version%202.0%20July%202021_508.pdf.

performance in isolation; in either case, we simply are not provided with a logical and practical representation of the overall performance and interconnected complexity of the entire system.

SCE will continue to evaluate tranching and RSE modeling approaches to ascertain if an approach can be leveraged that meaningfully reflects the somewhat unique complexities of overall cyber security. For purposes of future regulatory filings that directly implicate cyber security risk, we may propose some alternative approach if it seems appropriate for Commission consideration. This would, hypothetically, be an alternative that more accurately reflects and encompasses certain critical aspects of the cyber security risk landscape. We look forward to further dialogue with the Commission and stakeholders at a suitable juncture in the future.

We note that key mitigations such as training necessarily have a limited duration before the training must be retaken to continue its effectiveness, remind the training audience of the crucial concepts, and reinforce key messaging. Therefore, these mitigations have a shorter life than other mitigations such as capital investments whose useful life is measured in decades. So despite the effectiveness of Cyber Attack mitigations like training, the shorter lifespans translate to flat risk scores when we compare 2025 to 2028.

Table I-1
Summary of Pre- and Post-Mitigation LoRE and CoRE Risk Scores[9]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Cyber Attack	14.8	0.58	8.61	14.8	0.58	8.61

9 Refer to Cyber Attack RAMP Risk Model (excel file).

C. <u>Sensitive, Confidential Information Must Be Protected</u>

The RAMP process requires that SCE perform detailed and confidential[10] internal evaluations of our computing and operating systems, cyber security tools, and areas of vulnerability. This was a very valuable process, and SCE appreciates the opportunity to critically evaluate our cyber security program as it continually evolves. The detailed analysis that we performed internally around cyber security has informed the discussion we present in this chapter. However, SCE must necessarily safeguard this critical information. SCE's cyber security efforts include protecting the electric grid, which has been designated by the Department of Homeland Security (DHS) as critical infrastructure.[11] Therefore, a secure process for disclosing detailed tactics, techniques, and procedures to stakeholders to this proceeding is needed to help ensure its protection.

To help the Commission access the information necessary to answer specific questions regarding the cyber security risks, mitigations, and cost forecasts, SCE can provide an in-person briefing or engage in other appropriate methods to share additional detail that we cannot disclose in this Report for reasons of safeguarding the integrity of the grid and protecting public safety. One such method could be utilization of virtual sharing platforms. SCE provides a detailed workpaper that addresses and explains potential use of virtual sharing platforms in the specific context of the Commission's review of the RAMP Cyber Attack chapter.[12]

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[10] These evaluations required analyzing specific details concerning how various cyber defenses (such as software tools) perform in addressing different threats. Disclosing this information could potentially help an attacker gain crucial information about how SCE protects its systems, and where gaps might exist.

[11] DHS identifies 16 critical infrastructure sectors whose assets, systems, and networks, whether physical or virtual, are considered so vital to the United States that their incapacitation or destruction would have a debilitating effect on security, national economic security, national public health or safety, or any combination thereof. The U.S. Energy Sector is defined as one of these Critical Infrastructure sectors. This information is available at https://www.dhs.gov/critical-infrastructure-sectors.

[12] WP Ch. 7 – Potential Use of Virtual Sharing Platforms.

II.

RISK ASSESSMENT

A. Risk Definition and Scope

The scope of this risk chapter is defined in Table II-2 below.

Table II-2
Scope for SCE's 2022 Cyber Attack RAMP analysis

In Scope	• Unauthorized access to SCE's bulk electric system and distribution system controls, including our Supervisory Control and Data Acquisition (SCADA) network, industrial control systems (ICS), and other systems that access and utilize Critical Energy/Electric Infrastructure Information (CEII),* in addition, SCE's administrative and customer data systems are also included.
Out of Scope	• Secondary, indirect safety risks associated with cyber attacks.

*These are the systems that operate the electric system today, from central-station power plants, to our transmission and distribution power systems, and reaching through to the interconnection of utility-scale and localized, distributed energy resources.

An example of secondary, indirect safety risks would be the potential secondary safety impacts that could result if our control systems are compromised and the end result is a persistent blackout. SCE believes this is a viable and adversary-desired outcome that could potentially lead to significant safety and financial consequences. However, at this time, the modeling of such a scenario involves developing considerable assumptions and a virtual cascade of hypothetical events, and is therefore out of scope for this immediate RAMP analysis.

1. Increased Threat of Cyber Attack

The energy sector is under continuous cyber attack. The attack methods, strategies, and capabilities are constantly evolving as new types of attacks are discovered and carried out. Intrusion attempts against SCE continue to increase. Such attacks include computer viruses, worms, phishing, spyware, ransomware,[13] and advanced persistent threats. Any of these aggressive actions, if

[13] World Economic Forum Global Cyber Security Outlook 2022, p. 14. Ransomware attacks saw a significant increase in the first six months of 2021, with global attack volume increasing by 151%. The United States Federal Bureau of Investigation (FBI) has warned that there are now 100 different strains of ransomware in

(*Continued*)

successful, could significantly damage SCE's information systems. A prominent security-related periodical has noted: "The modern enterprise network has become expansive, porous, and completely blurred due to the large number of Internet-facing applications that have been deployed and adopted. The number of potential entry points into the enterprise network has proliferated uncontrollably." Furthermore, sophisticated cyber-attack capabilities and services are increasingly available to anyone with a motive and funds to pay for an attack. Third parties with ill intentions can increasingly access and procure sophisticated cyber-attack services for relatively little money, and at relatively low risk of detection and prosecution. Payment for cyber-attack services can cost less than $1,000.[14]

Cyber security's importance to utilities has expanded as systems and data have become more integral to business operations, and as the electric infrastructure has become more essential to national commerce and communications capabilities. Cyber attacks are continually growing in number and sophistication, and the availability of cyber weapons is on the rise as well. Therefore, maintaining a strong defense against cyber attack requires a continually evolving set of strategies.

2. Real-Life Examples of Costly Cyber Attacks

Recent examples of cyber attacks are well-documented in the news media and the intelligence community. These include but are not limited to:

- The cyber attack against Colonial Pipeline in which attackers used remote access to compromise internal systems. The incident resulted in the shutdown of Colonial

circulation globally. It is unlikely that this issue will diminish in pace or severity any time soon. There were, on average, 270 attacks per organization in 2021. This represents a 31% increase over 2020. Accessed at https://www3.weforum.org/docs/WEF_Global_Cyber security_Outlook_2022.pdf on February 16, 2022.

[14] World Economic Forum Global Cyber Security Outlook 2022, p. 12. The dark web is teeming with hacking services that offer comprehensive skills, affordable pricing, and quick timelines for engagement. Cybercriminals, also known as "blackhat" hackers, can be hired to break into social media accounts, erase debts, and even change students' grades. Prices for these services are often relatively affordable, especially considering the probability of personal or institutional damage. Prices tend to vary depending on the complexity of the required hacking activities, the desired outcome, and the victim's profile. It is relatively straightforward, however, to build an array of services with a budget of US$ 1,000 or less. Typical prices for services such as social media account hacking average US$ 230, while website hacking and changing school grades range from US$ 394 to US$ 526. Accessed at https://www3.weforum.org/docs/WEF_Global_Cyber security_Outlook_2022.pdf on February 16, 2022.

Pipeline's gasoline pipeline system, which carries approximately 2,500,000 barrels daily.[15]

- A long-term attack campaign against the software SolarWinds that resulted in approximately 18,000 users, including large corporations and the U.S. Government, being vulnerable to a variety of cyber attacks. The attack campaign also allowed the adversaries access into protected information systems.[16] According to a report from IronNet, the average cost per respondent was estimated to be 11% of their annual revenue, or $12 million per company.[17]

3. Cyber Attackers Targeting Electric Utilities

In 2021, the Dragos Corporation released a report on threat groups that have been targeting industrial control systems (ICS) along with specific industries. In this report, of the 15 threat groups being tracked, 11 are focused on attacking or gaining access to electric systems. These threat groups target technologies specific to generation, transmission, and distribution operations.[18]

In response to the recent attacks and increased threat activity, the U.S. Government has started developing plans and new regulatory requirements that affect utilities and critical infrastructure companies that were previously less-regulated in this arena. The U.S. Department of Energy (DOE) announced a 100-day plan to improve the cyber security posture of utilities in April of 2021. This effort aimed to raise awareness of the risk associated with ICS and prioritize the deployment of technology to gain visibility and monitoring within ICS environments.[19] For the organizations related to the pipeline

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[15] https://www.bloomberg.com/news/articles/2021-06-04/hackers-breached-colonial-pipeline-using-compromised-password.

[16] https://www.reuters.com/article/us-cyber-solarwinds-microsoft/solarwinds-hack-was-largest-and-most-sophisticated-attack-ever-microsoft-president-idUSKBN2AF03R.

[17] https://www.techrepublic.com/article/cyber security-study-solarwinds-attack-cost-affected-companies-an-average-of-12-million/.

[18] https://hub.dragos.com/hubfs/Reports/Global%20Electric%20Cyber%20Threat%20Perspective%20-%20Dragos%202021.pdf.

[19] https://www.energy.gov/articles/biden-administration-takes-bold-action-protect-electricity-operations-increasing-cyber-0.

sector, the Transportation Security Agency (TSA) released Security Directive (SD) 02. This provision requires operators of designated critical pipelines to initiate a cyber security program with mandatory reporting and communication requirements.[20] As electric utilities are often dependent on the delivery of fuels from pipeline companies and may have connected or dependent information systems, regulations such as SD02 may be applied or developed for non-CIP regulated companies in the near future. SCE is aware of these programs and the continued attention and scrutiny on cyber security across the critical infrastructure landscape.

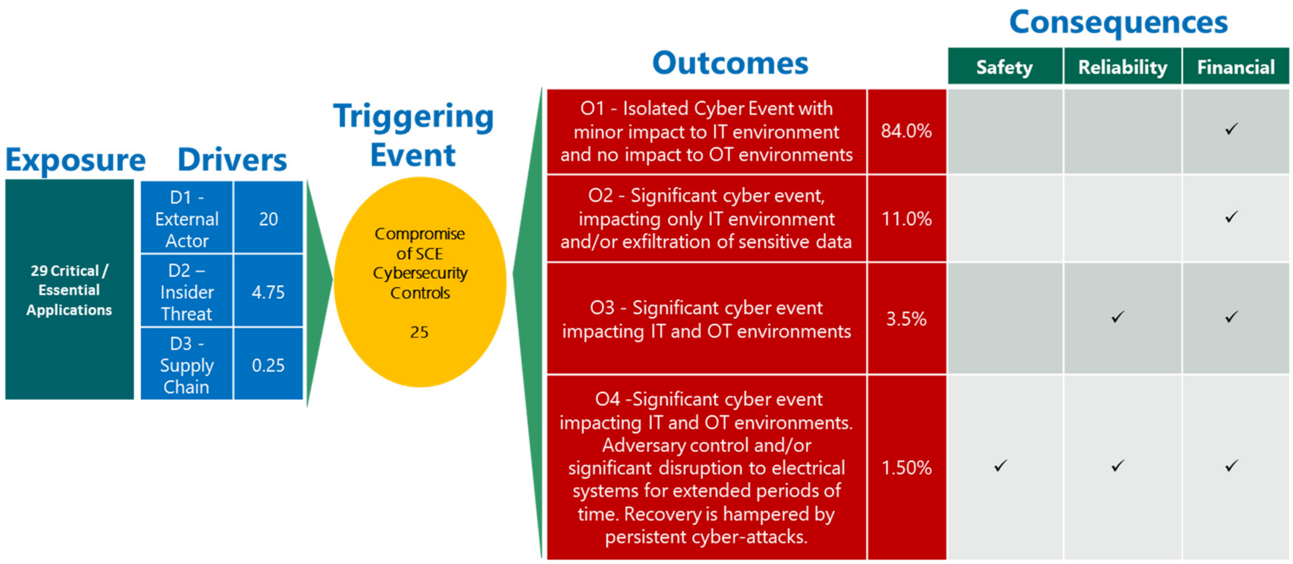
In a manner similar to other utilities across various countries, SCE has been prudently enhancing its cyber capabilities. We plan to maintain these defense capabilities over this RAMP period and beyond.

B. Risk Bowtie

To evaluate the Cyber Attack risk, SCE has constructed the risk bowtie as shown below in Figure II-1. SCE is defining the exposure of this risk to the company's 2022 list of essential/critical systems. A further discussion on these applications can be found below in Section II.F.

[20] https://www.dhs.gov/news/2021/07/20/dhs-announces-new-cyber security-requirements-critical-pipeline-owners-and-operators.

Figure II-1
Risk Bowtie for Cyber Attack[21]



C. Drivers

SCE has identified three key drivers for Cyber Attack that are further discussed below.

1. D1 – External Actor

An external actor is defined as any outside entity (a person, organization, nation-state, etc.) that attempts to maliciously bypass SCE's cyber security controls. External actors can, at the highest level, be categorized by motives and desired outcomes. In the past, the sophistication of these actors varied greatly. However, in recent years the availability of sophisticated cyber-attack tools and services has risen dramatically and is no longer a reliable indicator for attribution. The following section describes three different examples of External Actors, but is not a comprehensive list.

a) Cyber Crime Actors

Cyber Crime threat actors are motivated by one primary goal -- monetary gain. They seek to achieve monetary gain either through demanding ransoms or by obtaining personal information and selling it on the black market. These actors can vary in sophistication, but their objectives are fairly consistent. Attacks can range from traditional email or phone-based cybercrime

21 Please refer to WP. Ch. 7 - Baseline and Risk Inputs.

scams to sophisticated ransomware attacks which may significantly impact an organization. These threat actors can be well-organized, well-funded, driven by criminal enterprises, and are typically covert in their operations. Current trends reveal that the sophistication of tools and resources available to cyber criminals is dramatically increasing, and that there is little regard for any secondary consequences (such as business or grid operation disruptions) that may result from the attacker's pursuit of monetary gain. This was plainly evidenced in the Colonial Pipeline ransomware attacks in 2021.

b) Cyber Terrorism and Hacktivism Actors

Cyber terrorism and hacktivism attacks are typically motivated by ideological disagreements, political objectives, or a desire to retaliate for perceived injustice(s). These threat actors may perform deliberate large-scale interruption of services, orchestrate the creation of widespread panic, spread disinformation, or engage in other disruptive activities. They tend to target organizations with a specific mission or 'operation' with defined goals and objectives. They rely on causing disruption or disclosure of information that often has grave consequences to business operations and continuity.

Disruption of service is of particular concern to electric utilities, because attacks of this nature may impact reliability and/or safety. Attacks are typically short-term with a greater focus on causing visible damage than maintaining covert operations or campaigns to gain support and gather resources. These threat actors have a variety of attack methods from targeted phishing, disrupted denial of service (DDoS), website defacement, and network perimeter intrusions.

c) Nation State-Sponsored Actors

Nation state-sponsored cyber actors are groups who are funded by hostile nations. They target any organization that possesses information or capabilities that the hostile nation wants to clone or disable. These hostile cyber actors are typically sophisticated, well-funded, and have a clear set of operating steps to execute their mission. These actor groups are often closely affiliated with their country's intelligence, government, or military communities; they are instructed, trained, and organized by these foreign regimes solely for purposes of executing targeted and sophisticated attacks with clear motives and desired objectives related to their nation's advancement. These attacks often leverage advanced malware designed to gain covert persistence and long-term implantation for later use, such as for cyber warfare operations. Nation state-sponsored actors focus on long-term objectives and outcomes, often spending years collecting intelligence and gaining footholds within networks and systems.

2. D2 – Insider Threat

An insider threat is defined as an actor within SCE, such as an employee or contractor, who knowingly bypasses SCE cyber security controls with malicious intent. Insider threats pose a significant risk to any organization, but organizations with Operational Technology[22] (OT) environments are particularly vulnerable. The danger of insider threats, and what differentiates them from other threat actors, is that these individuals have, or had, a trusted role in the organization, valid credentials and access, and advanced knowledge of systems, processes, and operations that are not available to outsiders. As such, they can operate in a highly impactful and difficult-to-detect manner. Insider threat actors have always been a risk to organizations. However, recent increases in digitalization and automation have dramatically increased the ability of insider threats to amplify their impacts to SCE's systems.

Potential motives for insider threat attacks include:

- Gaining access to SCE's grid network;
- Causing loss of control of operating assets;
- Obtaining a competitive advantage;
- Intending to harm SCE due to adverse prior experiences with SCE; and
- Stealing proprietary or sensitive information that can be sold or brokered in underground marketplaces.

3. D3 - Supply Chain

In recent years, attacks on the supply chain have become an increasingly larger threat for SCE, and more broadly for the electric utility industry. Supply chain attacks and actors exploit trust

[22] "Programmable systems or devices that interact with the physical environment (or manage devices that interact with the physical environment). These systems/devices detect or cause a direct change through the monitoring and/or control of devices, processes, and events. Examples include industrial control systems, building management systems, fire control systems, and physical access control mechanisms." https://csrc.nist.gov/glossary/term/operational_technology.

relationships between SCE and third-party organizations, resources, and systems. Such attacks on SCE may originate through a compromising a vendor or partner organization; that organization may not even be aware of their role or involvement in such an attack on SCE.

An attack through SCE's supply chain, whether targeted or untargeted, could occur as follows:

- Compromising SCE-procured goods with embedded malware or other malicious code. Once such malware or code is on SCE's network, it can disrupt service, leak sensitive data, or harm system controls.
- Compromising or misusing SCE credentials or system access to remove, alter, or steal sensitive data, misconfigure OT devices, install malware, pivot to other systems or segments, or otherwise exploit system or device vulnerabilities.
- Attacking a third-party organization in SCE's supply chain, including vendors and business partners. Once the attack occurs, it can be exploited to violate the trust relationships between SCE and its partners. In the last several years, indirect attacks – successful breaches coming into an organization through third parties – have increased from 44% to 61%.[23]

4. Developing Driver Data

SCE identified the drivers that will continue to be the greatest threats to our operations. We evaluated these drivers using industry data. The availability of such industry data is necessarily limited. Similar to SCE, most utilities and companies that employ SCADA/ICS technologies are reluctant to disclose information or vulnerabilities, because sharing this information may put their systems at greater risk of future attack.

As such, where data was not publicly available, we augment our analysis based on our relationships with several federal government defense agencies and industry experts. Previously, SCE used Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) data released through

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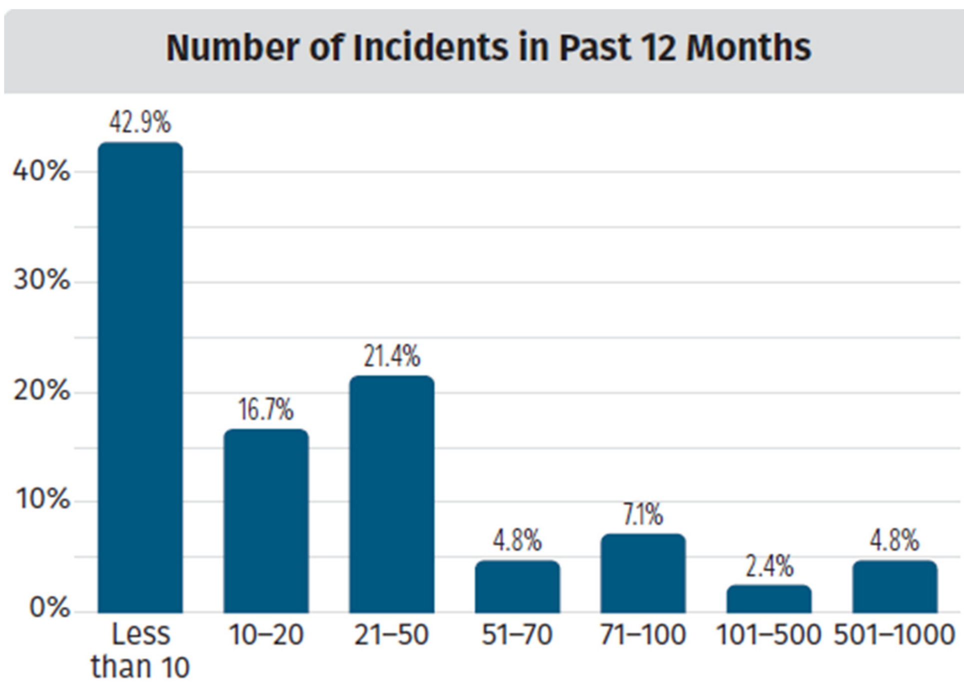
[23] Accenture's State of Cyber Security Resilience 2021 report - https://www.accenture.com/_acnmedia/PDF-165/Accenture-State-Of-Cyber security-2021.pdf.

the Year in Review (YIR) reports to calculate an estimation of the number of incidents per year that critical infrastructure companies reported, along with the percentage of incidents that became breaches or intrusions. ICS-CERT is now part of the Cyber security and Infrastructure Security Agency (CISA), and the YIR reports have not been released since FY 2016. To offset this lack of data, SCE based our estimation of number of triggering event frequency (TEF) on the Verizon Data Breach Incident Reports (DBIR)[24] and the SANS Institute's 2021 OT/ICS Cyber Security Survey.[25]

As shown below in Figure II-2, 81% of respondents in the SANS Survey had between 1 and 50 incidents. From this data, we are estimating an annual TEF of 25 for calculation purposes. From the DBIR, the breakdown of attackers is estimated as 80% for External, 19% for Internal, and 1% for Partner/Supply Chain.

Figure II-2
Number of Incidents for SANS Survey



24 https://www.verizon.com/business/resources/reports/dbir/.

25 https://www.nozominetworks.com/downloads/SANS-Survey-2021-OT-ICS-Cyber security-Nozomi-Networks.pdf.

D. Triggering Event

In the context of this risk assessment, the triggering event is defined as a "Compromise of SCE cyber security controls" which includes disruption of operations from a cyber attack with the ability to damage, destroy systems, or interrupt critical business functions through loss of data, data integrity, loss of control, adversary control of grid control systems/SCADA, and/or ransomware attacks. Such an attack could result in an inability to deliver electricity to customers, compromise of sensitive confidential personal and other data, loss of intellectual property, loss of the grid for an extended period, and/or catastrophic outcomes at the individual and/or community level.

E. Outcomes and Consequences

SCE identified a range of outcomes that would occur if our control systems were compromised. In developing these outcomes, we took into account evolving cyber threats and specific aspects of our grid infrastructure and operations. SCE estimated the expected likelihood of each outcome occurring, should the triggering event occur. This effort yielded the following outcome likelihoods as shown in Figure II-1 above.

Figure II-1 indicates the consequence dimensions we modeled for each of the outcomes. All of the safety consequences of this risk would be effectuated through O4 (Significant safety and/or reliability impact or loss of control of OT systems)). In addition, the majority of the reliability and financial consequences originate from two outcomes: O3 (Disruptive impacts to OT systems or assets that may, or may not, involve IT systems) and O4 (Significant safety and/or reliability impact or loss of control of OT systems).

The sections that follow detail the inputs we used to arrive at these results.[26]

1. O1 - Isolated cyber event with minor impact to IT environment and no impact to OT environments

In this outcome, a cyber incident originated by an external actor, insider threat, or through SCE's supply chain has been minimally successful. The incident, by its nature or due to the

[26] Please refer to WP. Ch. 7 - Baseline and Risk Inputs.

actions of SCE's security team, is isolated to IT systems and presents only a minor impact to regular IT operations, and no impact to OT environments or assets. As such, this category of outcome does not directly affect SCE's ability to safely and reliably deliver power to its customers. It may, however, result in IT remediation costs. Remediation can involve external cyber security resources to determine if a more involved compromise occurred.

Real-life examples of this outcome could include exploitation of an unpatched IT vulnerability, unauthorized changes to an IT system by an employee or vendor (either intentional or unintentional), and isolated malware infection of an IT workstation or system.

2. <u>O2 – Significant cyber event impacting only the IT environment and/or exfiltration of sensitive data.</u>

In this outcome, a cyber event has caused a significant impact to IT systems and/or exfiltration of sensitive data. However, the event does not impact OT systems, assets, or the safe and reliable delivery of power to SCE customers. In this outcome, essential IT and business operations are disrupted, or sensitive data, such as intellectual property (IP), personally identifiable information (PII), customer data, and/or NERC CIP protected data is exfiltrated outside of SCE's network and protective controls.

In the case of IT and business operations disruption, we may need to activate business continuity plans and/or initiate data recovery or backup restoration activities. Significant loss of core business functions and efficiency impacts are likely. Customer-related consequences, such as billing delays, inaccurate billing, or inaccessible customer web portals, may result.

In the case of exfiltration of sensitive data, adversaries can gain advanced levels of knowledge on how our grid is designed and operated. Loss of certain protected data can lead to regulatory fines and penalties. Loss of customer data will diminish customer confidence and trust, and may also lead to regulatory scrutiny and/or financial loss, among other issues.

Cyber events with O2 outcomes typically require extensive computer forensics and incident response support, often requiring third-party services and expertise. Such services typically cost hundreds of dollars per hour and can require hundreds of hours of effort to fully identify the attack vector(s) used by the adversary, determine the full extent of system impact and data-loss, and remediate the underlying vulnerability(ies) exploited by the attacker.

3. O3 – Disruptive impacts to OT systems or assets that may, or may not, involve IT systems

In this outcome, regular electrical system control is disrupted due to cyber events impacting OT systems or assets. These impacts may be the result of cyber events originating on IT systems, such as ransomware attacks, or may be isolated to the OT environment. This outcome is differentiated from outcome O4 in that the cyber event or attacker activity impact of outcome O3 is limited to our inability to fully utilize OT system functions. (This is also known as denial of use.) Loss of control of electrical systems due to denial can potentially result in short-term harmful effects, including the following:

- Disabling the connectivity between SCE transmission and distribution sites, thus necessitating manned support for locations which are typically unmanned.
  This causes increased spending for overtime, and less efficient manual transfers of connections.
- Disabling remote grid management functions. Our personnel must then travel to the physical site locations to support restoring operations for affected components.

In an industrial environment, loss of visibility or control has a varied impact, which can range from lessened Overall Equipment Effectiveness (OEE) up to potential process failure of generation, transmission, and distribution functions, and a resulting disruption of operations.

4. O4 – Significant safety and/or reliability impact or loss of control of OT systems

This outcome's severity is extremely high due to significant degradation of the safe and/or reliable operation of OT systems related to cyber events. This outcome is differentiated from outcome O3. Outcome O3 is limited to denial of use, while O4 implicates OT systems that are erratic, unpredictable, potentially destructive, and/or are under adversary control.

Adversary control, whether occurring directly or via malicious code, happens when an adversary in theory could successfully penetrate our systems and could execute controls in the same manner as SCE operators. This would allow an attacker to control the flow of power, perform switching operations, and undertake other conflicting, damaging, dangerous, or destabilizing actions. Such actions would prevent SCE from safely managing electric system operations, and would cause outages or periods of unstable power delivery to customers.

Adversary control of our electric system could potentially result in short-to-medium-term outages within SCE's territory. Adversary control may also result in damage to, or destruction of, electric system components, and/or physical harm to people, property, infrastructure, or the environment.

Financial consequences associated with this outcome may be substantial. Examples of financial impact include:

- Recovering and/or replacing the hardware and software systems that would likely be damaged after an attack of this magnitude.
- Performing a comprehensive forensic analysis, adversary eviction, and rapid mitigations to prevent similar incidents.
- Harm to people, property, infrastructure, and/or the environment.

F. <u>Tranches</u>

SCE assessed several factors when determining the tranches for the Cyber security risk, including but not limited to cyber security control programs, geographic location, and population type. Ultimately, SCE elected to use the company's 2022 list of essential/critical IT and OT systems and the subsequent impact to the business from a cyber security compromise to group the risk and create the tranches.

SCE's assessment of cyber security risks was refined into three separate tranches that were considered to have homogenous risk profiles. The tranche categorization SCE specifies in this RAMP aligns with SCE's existing system protection separation between transmission and distribution.
The tranches are defined by groupings of distinct IT/OT applications and the corresponding network infrastructure needed to support those applications. Our tranche categorization also allows us to use as

attributes our existing financial structure and existing grouping of cyber security controls to determine what level of impact the loss of those systems would be to SCE's operational posture.

Below, we outline the three tranches:

- Tranche 1 – This Tranche contains applications essential to our Bulk Power System (BPS). A cyber security compromise in this tranche will impact SCE's ability to efficiently participate in generating and transmitting electricity for our customers and engage in system-balancing activities with other utilities. Examples of applications in this tranche include Energy Management Systems (EMS) and Generation Management Systems.
- Tranche 2 – This tranche represents applications that are essential to SCE's distribution system. A cyber security compromise in this tranche will impact the reliable delivery of electricity to SCE customers, causing outages and instability. Examples of applications in this tranche include Distribution Management System (DMS) and Outage Management Systems (OMS).
- Tranche 3 – Lastly, Tranche 3 contains those systems essential to our business operations. A compromise to systems in this tranche will impact operational data and activities, such as customer information, communication capabilities, and regulatorily-required reporting and documentation.

G. Related Factors

For purposes of this discussion, SCE defines related factors as factors that are not directly included in the risk modeling but can impact the driver frequency and the likelihood of certain outcomes. The identified related factors for the Cyber Attack chapter of RAMP are discussed below in Table II-3.

Table II-3
Related Factors Impacting Cyber Attack

Related Factor	Impact Description
Major Physical Security	A major physical security breach could allow an external actor defined as any outside entity (i.e., a person, organization, nation-state, etc.) to gain access to SCE's cyber security infrastructure.
Geopolitical Tension	Political extremism and increased geopolitical tension could lead to an increase in the driver frequency D1 – External Actors (https://www.cnn.com/2022/03/21/politics/biden-russia-cyber-activity/index.html).
Widespread Outage	A cyber-attack could lead to the loss of control of our electric system, resulting in a widespread outage. For additional information on general efforts that SCE takes to address please refer to Appendix E – Widespread Outage.
Transmission and Substation Asset Failure	A cyber-attack could lead to the loss of control of our transmission and substation assets. As discussed in Appendix C – Transmission and Substation Assets, this risk did not rise to the level of inclusion as a top safety risk within our RAMP report and was not quantitively modeled.

III.

CONTROLS

As cyber security threats significantly increase in volume and complexity year-over-year, SCE must continually refine and adapt its defense strategies. SCE employs a defense-in-depth cyber security strategy. This strategy utilizes multiple layers of protection, proactive vulnerability testing, and assessment of the grid environment to prevent unauthorized access and control of SCE's systems.

SCE organizes its cyber security defense into the following program areas: Perimeter Defense, Interior Defense, Data Protection, SCADA Cyber Security, and Grid Modernization Cyber Security. Each of these controls (as shown below in Table III-4) represents a risk reduction strategy for the Cyber Attack RAMP risk. SCE modeled the risk reduction in driver frequencies only for this RAMP exercise; SCE did not model how the controls may impact outcomes or consequences.

Table III-4
Inventory of Cyber Security Controls

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
C1	Perimeter Defense	D1, D2, D3	-	-	Yes	All
C2	Interior Defense	D1, D2, D3	-	-	Yes	All
C3	Data Protection	D1, D2, D3	-	-	Yes	All
C4	SCADA Cybersecurity	D1, D2, D3			Yes	All
C5	Grid Mod Cybersecurity	D1, D2, D3			Yes	All

A. C1 – Perimeter Defense

Perimeter Defense is the first line of defense against cyber attacks. It is the outer layer of protection for our defense-in-depth approach to cyber security. It represents the technologies (e.g., firewalls and intrusion detection systems) and related processes, procedures, hardware, and software to protect critical systems such as SAP, customer data, and ultimately our grid from unauthorized access. When properly configured, the perimeter defenses should only permit those activities required to conduct business. In a perimeter defense security model, the perimeter technology prevents, absorbs, or detects attacks, thereby reducing the risk to critical back-end systems.

In addition, the Perimeter Defense program will continue to refine existing intrusion protection measures and implement new ones (such as systems with deep-scanning capabilities and advanced data analytics capabilities) to better detect unauthorized intrusions. This control will integrate these new tools and controls into our existing Perimeter Defense layer to create common, unified monitoring that lets us rapidly respond to security events.

1. Drivers Impacted

Perimeter Defense reduces the frequency of all drivers by, among other things, intercepting attempted communications and attacks from external attackers. It also helps us determine whether external communications are intended to harm SCE, including whether the communication is an attempt to trick or coerce a user into clicking internet links or providing information.

2. Outcomes & Consequences Impacted

For purposes of this RAMP analysis SCE did not model impacts to the outcomes or consequences.

3. Control Options Modeled for C1 (Perimeter Defense)

Perimeter Defense is a core control within our defense-in-depth cyber security strategy. As such, when evaluating alternatives to this control, SCE contemplated different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools associated with the deployment of this control over the RAMP period. To help us estimate the efficiency and effectiveness of Perimeter Defense in reducing risk, we consulted subject matter experts.

B. C2 – Interior Defense

Interior Defense comprises protection controls securing SCE's internal business systems from unauthorized users, devices, and software. It also includes the use of analytics to anticipate and prevent attacks from happening. Additionally, Interior Defense helps identify and block security breaches from personnel who have some level of authorized access to the systems.

Users of SCE's business systems can propagate and/or launch malware knowingly or unknowingly. Without the Interior Defense controls, SCE could not identify or react to an infected computer or malicious breach attempting to infect others on the network. By quickly identifying suspicious activity, SCE can take earlier action to minimize any potential damage from the attack.

The Interior Defense mitigation lets us monitor SCE's internal business network, in real-time and with advanced and integrated capabilities. This makes it difficult for unauthorized users to access our systems, and also protects against authorized users knowingly or unknowingly propagating cyber security attacks. This mitigation also makes it harder for rogue devices or software to access SCE systems and confidential data or to cause business disruption. The mitigation will also address Advanced Persistent Threats (APT) by using advanced data collection and analysis technologies that can quickly detect potential questionable activity.

To accomplish all of this, the Interior Defense mitigation program will:

- Extend SCE's Identity and Access Management system to newer generation security technology;
- Enhance and expand SCE's data collection capabilities to retrieve (and, as needed, collect) disparate pieces of data to form a clear picture of threats and attacks;
- Implement technology capabilities so that SCE can analyze collected information for security threats in a more automated and effective manner; and
- Initiate automated alerts when questionable activity is detected. This will let us stay ahead of possible threats and help prevent attacks from happening.

1. Drivers Impacted

Interior Defenses are designed to reduce D2 (Insider Threat), as well as any external threat D1 (External Actor) or D3 (Supply Chain) threat that successfully bypasses the Perimeter Defenses. A threat that originates on or accesses the SCE internal network will be neutralized by Interior Defense at the endpoint (workstation, laptop, or server). When an attack occurs to a system that is directly connected to the SCE internal network via physical interface, we counter the attack through access controls that disallow unauthorized systems.

2. Outcomes & Consequences Impacted

For purposes of this RAMP analysis SCE did not model impacts to the outcomes or consequences.

3. Control Options Modeled for C2 (Interior Defense)

Interior Defense is a core control within our defense-in-depth cyber security strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. To help us estimate the efficiency and effectiveness of Perimeter Defense in reducing risk, we consulted subject matter experts.

C. C3 – Data Protection

The Data Protection program safeguards the computing environment housing SCE's core information. Among other things, this program will protect confidential SCE information that resides on all computing devices; this is protection from unauthorized use, distribution, reproduction, alteration, or destruction.

The Data Protection program will leverage specialized technology to better protect and encrypt data fields within files, enhance access controls to protect sensitive business information, and secure business information stored at external sites that host SCE business systems. In addition, this mitigation program will implement enhanced controls for granular data protection by deploying Data Loss, Categorization, and Identification tools. These controls will:

- Automate data classification by tying together the different systems that contain data and the ability to classify them;
- Monitor and alert unauthorized access to business information by leveraging the monitoring and data analysis environment with new toolsets;
- Manage business information that is saved on personal devices; and
- Manage and restrict the copying of business information to portable devices.

1. Drivers Impacted

All Drivers are impacted by the functions provided by this mitigation. The use of data classification and role-based access controls prevents unauthorized users and attackers from accessing sensitive SCE information.

2. Outcomes and Consequences Impacted

For purposes of this RAMP analysis SCE did not model impacts to the outcomes or consequences.

3. Control Options Modeled for C3 (Data Protection)

Data Protection is a core control within our defense-in-depth cyber security strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. To help us estimate the efficiency and effectiveness of Perimeter Defense in reducing risk, we consulted subject matter experts.

D. C4 – SCADA Cyber Security

This project provides enhanced security measures by implementing risk-reduction methods specifically tailored for SCE's SCADA systems. SCE's SCADA systems remotely control and monitor the electric grid.

SCADA Cyber Security protects legacy and future industrial control systems that are currently connected via routable networks. As threats evolve, SCE must take measures to improve visibility, detection, and protection controls by:

- Building a secure network to protect the administrative interfaces of critical tools;
- Developing device and user access controls to secure user interactions with control systems and to restrict access to the minimum level required for the user's particular role,
- Implementing current generation protections to identify malware,
- Deploying vulnerability management tools to search for and identify known vulnerabilities,
- Providing data encryption services;
- Implementing integration tools to gather intelligence and monitor and analyze potential and actual threats; and
- Procuring government issued secure technology to defend against advanced attacks.

1. Drivers Impacted

All three Drivers are impacted by this mitigation. SCADA protection makes it far more difficult for attackers to enter the electric grid network without proper credentials. External actors and the supply chain must pass through controls that are similar to Perimeter Defense, but applied at the edge of the grid network. Insider Threat actors will also be challenged by this mitigation.

2. Outcomes & Consequences Impacted

For purposes of this RAMP analysis SCE did not model impacts to the outcomes or consequences.

3. Control Options Modeled for C4 (SCADA Cyber Security)

SCADA Cyber Security is a core control within our defense-in-depth cyber security strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. To help us estimate the efficiency and effectiveness of Perimeter Defense in reducing risk, we consulted subject matter experts.

E. C5 – Grid Modernization Cyber Security

The Grid Modernization Cyber Security program[27] focuses on addressing the comprehensive security and data protection needs of all new infrastructure and application assets being added through SCE's Grid Modernization program.

As described in SCE's Test Year 2021 GRC, SCE is upgrading several legacy systems that are obsolete, such as the old NetComm wireless network, the existing Distribution Management System (DMS) and Outage Management System (OMS). The Grid Modernization Cyber Security program addresses the critical need for modern and robust cyber security measures and controls that detect, isolate, fix or remove, and restore electric distribution grid systems and devices as quickly and efficiently as possible. The program seeks to accomplish this through a combination of infrastructure, applications, and threat intelligence initiatives.

SCE's new Grid Modernization Communications system comprising the Field Area Network, Common Substation Platform (CSP), and Wide Area Network will provide the opportunity to significantly enhance the underlying cyber security capabilities. Indeed, through this cyber security program, the new communication paths designed for two-way data flows will be actively monitored, maintained, and controlled. In addition, advanced infrastructure service layers will be deployed to extend strong cyber security controls to the edges of the grid network.[28]

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[27] Given the sensitive nature of cyber security information, only limited content is being presented in this public document. Specific details can be provided to the Commission in confidential briefings as discussed above.

[28] SCE defines the edge of the grid network as the portion of the system between the distribution substation and the customer meter.

Moreover, the new grid control applications planned by the GMS program will be designed with cyber security controls throughout their implementation lifecycle, thus integrating strong access controls, secure communications, and secure programming code. With the combination of WAN and CSP, secure network segmentation schemes will be configured, and secure advanced remote access to the substation will provide complete visibility to SCE's Security Operations Center.

Furthermore, this program will invest in additional software and hardware tools to secure externally-facing connections with customers and/or third parties (e.g., DER aggregators) that will interact with SCE via a variety of access methods, such as the DRP External Portal (DRPEP) and Grid Interconnection Processing Tool (GIPT). Lastly, the Grid Modernization Cyber Security program will integrate cyber security operations with external government organizations to enhance incident investigation and response capabilities.

Despite the implementation of strong preventative controls, cyber security for grid modernization designs must account for the possibility that compromise of a system on the distribution network will occur. A compromised system on the grid enables an avenue of attack to escalate privilege, launch malware attacks, or render a grid system inoperable. Preventative controls will be imperative in defending SCE's infrastructure, and possessing the ability to identify when a compromised system behaves anomalously and execute an automated response to isolate the system and minimize its potential impact to the grid operations. This program's scope addresses the multiple layers of technology, vulnerability testing, resources, processes, and procedures that are necessary which include:

- Grid Data Center Cyber Security foundational capabilities providing detection and response
- Industrial Control Systems (ICS) Threat & Asset Visibility and Information Protection capabilities: Vulnerability Management, Boundary Defense, Access Control, System Response, Device Management, Malware Protection
- Cyber Security Lab/destructive test environment
- Grid Data Center upgrade/replace existing tools
- Grid Data Center capacity/technology enhancements
- Government Technology Transfer

1. Drivers Impacted

All drivers are impacted by this mitigation, since it applies multiple layers of protection at the edge of the access to our network, as well as internally within the SCE grid environment. The mitigation prevents unauthenticated users and unauthorized SCE personnel from accessing the network. The mitigation also allows us to monitor different network connection and transportation types (such as fiber and radio frequency) for misuse.

2. Outcomes & Consequences Impacted

For purposes of this RAMP analysis SCE did not model impacts to the outcomes or consequences.

3. Control Options Modeled for C5 (Grid Modernization Cyber Security)

Grid Modernization Cyber Security is a core control within our defense-in-depth cyber security strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. To help us estimate the efficiency and effectiveness of Perimeter Defense in reducing risk, we consulted subject matter experts.

IV.

MITIGATIONS

In the normal course of business, and as part of developing this RAMP report, SCE regularly assesses whether there are more effective ways to mitigate cyber security risks while continuing to keep costs at an appropriate level. Cyber security solutions are a continually evolving field, just as cyber attacks continue to evolve in their sophistication and impact. A number of new cyber security approaches are embodied in specific projects or tools that are incorporated into each program we discuss in Section III above.

SCE values its dialogue with the Commission and other stakeholder with regard to cyber security. But the specific tools and the details of our safeguards cannot be publicly disclosed without compromising our cyber security capabilities and making cyber attacks easier for a party that wishes to harm our systems, our delivery of safe and reliable service, or indeed our customers themselves.

To take just one basic example of this concern: some of the cyber security tools that SCE uses are purchased from expert vendors in the field. If SCE publicly reveals that it relies on a particular tool, then if a cyber attacker finds a gap in that tool or a way to bypass it, then the cyber attacker can direct its attack to any or all of the companies that use that particular tool. The cyber attacker can find the gap elsewhere, and then exploit it against SCE because SCE has publicly disclosed that it uses the same tool.

Despite these concerns, if the Commission wishes to learn more about certain confidential cyber security projects, tools, and strategies, SCE would welcome the opportunity to discuss with the Commission potential paths such as an in-person briefing or a secure viewing of appropriate documents and data. SCE includes a workpaper that outlines the potential use of virtual sharing platforms as a way for SCE to share appropriate cyber security information and materials with the Commission reviewers.[29]

V.

FOUNDATIONAL ACTIVITIES

IT operations, by their nature, include many aspects of foundational cyber security controls and best practices. Cyber security functions such as multi-factor authentication and role-based access management have become commonplace and expected in enterprise IT solutions. As such, differentiating core business functions from targeted cyber threat reduction initiatives can be challenging. As new threats and attack vectors are discovered and leveraged by attackers, unique, novel, and sometimes expensive mitigation controls can be necessary. For example, an increase in supply-chain attacks may require tailoring of vendor management processes to address increased risks, requiring considerable effort and cost to implement. However, over time these process changes become part of standard operating procedures. Additionally, technical controls are often integrated into standard products, systems, and services in a commoditized manner. Once this commoditization occurs, it can be difficult or impossible to segregate the cost of cyber security controls from core business operations and functionality.

[29] WP Ch. 7 – Potential Use of Virtual Sharing Platforms.

VI.

PROPOSED PLAN

Cyber security risk is inherently difficult to quantify. The risks and threats that we face as a utility in one of the largest metropolitan areas[30] in the world are vast and diverse. Trying to forecast the probability of successful breaches of our systems controls involves making a series of educated assumptions based on what we know about our existing defenses, the demographics and capabilities of our attackers, and the growth and complexity of the attacks we will face in the future.

In addition, the risk of cyber attack has changed significantly due to global politics and the associated actions of nation-states. Cyber attacks are evolving at a rapid pace, and the mitigations that worked against previous attacks may not be as effective against future attempts. Cyber security threats are not limited to our service area, but instead can originate from virtually anywhere across the world. Cyber security challenges can also be triggered or motivated by social unrest, political differences and upheavals, and religious and cultural factors.

Measuring the effectiveness of controls and mitigations becomes equally difficult when we do not have a base level of historical data and experience to draw from. Due to this, SCE reviews publicly-available information as well as reports issued by the Department of Homeland Security (DHS) to stay up-to-date on current cyber security threats. Fortunately, SCE has not experienced a significant breach of our control systems to date. However, given the essential services we provide to our millions of customers, we must remain vigilant in guarding our systems and assets from sophisticated and highly determined cyber threat actors.

Through the development of the 2022 RAMP report, SCE has been able to take additional steps forward in quantifying the cyber attack risk to SCE. The risk bowtie model has been instrumental in better understanding the relationships between risk drivers, mitigations, and outcomes and has aided SCE in evaluating and improving the effectiveness of our controls and mitigations. This model has been

[30] Southern California, as a service area, comprises a high density of customers to geographic areas, headquarters a great deal of the media/entertainment industry, and has a high profile in the news. Thus, a cyber attack in the Southern California region would be a much more reported-upon event and would provide the attackers with relatively higher visibility.

updated with more recent cyber security attack analyses and an improved mitigation effectiveness determination approach since the 2018 filing.[31]

SCE performed analysis to determine the risk mitigation effectiveness of SCE's cyber security defense program areas (Perimeter Defense, Interior Defense, Data Protection, SCADA Cyber Security, and Grid Modernization Cyber Security) related to the Drivers in the risk bowtie (External Actors, Insider Threat, and Supply Chain). The purpose of this analysis was to estimate the extent to which the cyber security defense programs, also known as Controls, mitigate negative Outcomes of a cyber security attack by reducing the frequency of successful compromise of cyber security systems.

SCE has evaluated each control as discussed above in Section III and has developed a Proposed Plan for addressing this risk, as shown in Table VI-5 below. The pre- and post-mitigation LoRE, CoRE and risk scores for the Proposed Plan are summarized by tranche below in Table VI-6.

[31] Refer to WP. Ch. 7 – Mitigation Effectiveness.

Table VI-5
Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[32]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Perimeter Defense	$1.8	$26	1,430
C1 - T2	Perimeter Defense	$2.4	$34	575
C1 - T3	Perimeter Defense	$7.7	$112	2
C2 - T1	Interior Defense	$1.0	$5	1,952
C2 - T2	Interior Defense	$1.3	$7	784
C2 - T3	Interior Defense	$4.3	$22	3
C3 - T1	Data Protection	$1.0	$8	1,871
C3 - T2	Data Protection	$1.3	$10	751
C3 - T3	Data Protection	$4.2	$34	3
C4 - T1	SCADA Cybersecurity	$1.7	$8	651
C4 - T2	SCADA Cybersecurity	$0.6	$3	1,045
C5 - T1	Grid Mod Cybersecurity	$5.7	$93	71
C5 - T2	Grid Mod Cybersecurity	$1.9	$31	114
Total		**$34.8**	**$392**	**-**

32 Please refer to Cyber Attack RAMP Risk Model (excel file) and WP. Ch. 7 – Cyber Attack RAMP Financials.

Table VI-6
Pre- and Post-Mitigation LoRE, CoRE and Risk Scores[33]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Cyber Attack	14.8	0.58	8.61	14.8	0.58	8.61
T1 - Bulk Power System	4.2	1.33	5.59	4.2	1.33	5.59
T2 - Distribution System	2.3	1.33	2.99	2.3	1.33	2.99
T3 - Business Operations	8.3	0.004	0.03	8.3	0.004	0.03

A. Overview

SCE evaluated our internal defenses against cyber attack capabilities and threats. This evaluation indicated that SCE appears to have implemented adequate cyber defense strategies for the known threats that exist today. However, in the course of developing this RAMP report, we have identified increased exposure and risk in the future. As such, in the Proposed Plan, SCE continues to deploy and enhance its defense-in-depth cyber security approach by maturing and expanding existing cyber security practices. In addition, SCE supplements this work with enhanced capabilities, tools, and resources to address the growth of cyber attack risks at a reasonable level of spend. The Proposed Plan supports ongoing cyber security defensive activities and investment in the right technologies and capabilities to protect SCE and its customers.

The Proposed Plan carries forward the scope of work from our existing activities, and adds additional training, penetration testing, vulnerability assessments, and related services which may be provided by external entities where it is productive and efficient to leverage their particular specialties. Training is essential in helping ensure that SCE personnel are up-to-date on the latest technology and techniques that are used to protect and operate the grid network. Cyber security technology can offer new capabilities for existing products during the asset's life cycle. In order to take advantage of these capabilities, training is key. Vulnerability assessments performed by independent and trusted third

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[33] Please refer to Cyber Attack RAMP Risk Model (excel file).

parties evaluate how SCE manages risks associated with vulnerabilities in the network environments. These assessments can also serve as checkpoints for ongoing projects. Use of penetration testing allows SCE to see:

- What an adversary would identify as key assets for compromise;
- What attack paths and techniques apparently would succeed within the SCE environment; and
- How practically effective the security mitigations are in preventing, mitigating, or detecting an attack.

B. <u>Execution Feasibility</u>

SCE evaluated the feasibility of executing the Proposed Plan based on current organizational capabilities and the technical limitations of our internal computing and operational systems. The Proposed Plan appears to be feasible and prudent to execute.

C. <u>Affordability</u>

The Proposed Plan strikes a reasonable balance between cost and risk reduction. The Proposed Plan requires modest additional funding as compared to Alternative Plan #1, but is expected to deliver greater risk reduction benefits. The Proposed Plan will be used to support an increasing level of cybersecurity preparation while adjusting to new tactics, techniques, and procedures that attackers develop and utilize. This preparation includes upgrading systems, investing in new technologies, training SCE personnel to maintain and enhance their cybersecurity skills, and assessing both current environments and projected future ones.

The Proposed Plan does not deliver as much risk reduction as Alternative Plan #2 does. However, there are additional costs in Alternative Plan #2 associated with the level of implementation of the controls, which include accelerating planned projects already on the cyber security roadmap. Based on what we know today, these additional costs do not appear to reduce the risk by a sufficient amount to justify the increased spending.

SCE also contemplated whether to pursue Alternative Plan #2, but chose not to for the following reasons: (1) SCE must balance the need to invest in cyber security on the one hand, versus the need to spend to address other risks and meet other important objectives on the other hand; (2) at this time, our evaluation indicates that the Proposed Plan represents a reasonable level of commitment and spend over the RAMP period; and (3) SCE does not currently believe that deploying the additional cyber security enhancements in Alternative Plan #2 is an operationally practical, technologically mature, or fiscally prudent choice at this time. This is discussed further in Section VII, where we examine Alternative Plan #2 in more detail.

D. Other Considerations

Advances in the sophistication of cyber attack threats and the deployment of new attack methods may render the Proposed Plan ineffective. SCE must predict where the threat will go in the future. If we have not predicted this correctly, the mitigations laid out in the Proposed Plan may not be sufficient. In addition, global politics, social unrest, and war have led to increased numbers of, and greater sophistication of, attacks by nation-states on our electric system. As discussed previously, SCE builds, maintains, and operates critical energy infrastructure that could be more susceptible to attack as the global environment changes.

VII.

ALTERNATIVE PLANS

A. Alternative Plan #1

SCE evaluated other options to address the Cyber Attack risk and developed an alternative mitigation plan as shown in Table VII-7. The pre- and post-mitigation LoRE, CoRE and risk scores for Alternative Plan #1 are summarized by tranche below in Table VII-8.

Table VII-7
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[34]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Perimeter Defense	$1.4	$26	1,272
C1 - T2	Perimeter Defense	$1.9	$34	511
C1 - T3	Perimeter Defense	$6.1	$112	2
C2 - T1	Interior Defense	$0.7	$5	1,615
C2 - T2	Interior Defense	$1.0	$7	648
C2 - T3	Interior Defense	$3.1	$22	2
C3 - T1	Data Protection	$0.7	$8	1,608
C3 - T2	Data Protection	$1.0	$10	646
C3 - T3	Data Protection	$3.2	$34	2
C4 - T1	SCADA Cybersecurity	$1.3	$8	551
C4 - T2	SCADA Cybersecurity	$0.4	$3	885
C5 - T1	Grid Mod Cybersecurity	$4.6	$93	55
C5 - T2	Grid Mod Cybersecurity	$1.5	$31	89
Total		**$27.0**	**$392**	**-**

[34] Please refer to Cyber Attack RAMP Risk Model (excel file) and WP. Ch. 7 – Cyber Attack RAMP Financials.

Table VII-8
Pre- and Post-Mitigation LoRE, CoRE and Risk Scores[35]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Cyber Attack	17.7	0.578	10.24	17.7	0.578	10.24
T1 - Bulk Power System	5.0	1.328	6.65	5.0	1.328	6.65
T2 - Distribution System	2.7	1.328	3.56	2.7	1.328	3.56
T3 - Business Operations	10.0	0.004	0.04	10.0	0.004	0.04

1. Overview

Similar to the Proposed Plan, Alternative Plan #1 continues to deploy SCE's defense-in-depth cyber security approach. This plan reduces operating costs but also reduces mitigation effectiveness as compared to the proposed plan.

2. Execution Feasibility

Alternative Plan #1 represents a reduced scope of work for each mitigation program relative to the Proposed Plan. Since SCE believes the Proposed Plan can be executed, this plan should likewise be feasible to execute.

3. Affordability

This Alternative Plan #1 represents the least-cost option. While this is the least-cost option, the overall risk reduction is the lowest out of the three mitigation plans identified. Alternative Plan #1 provides the lowest amount of funding for cyber security testing, and would limit strategic upgrades to newer technologies and training in the newest defensive capabilities for SCE- deployed equipment. With cyber attacks growing in complexity and number, this approach would reduce the effectiveness of our personnel and security controls. This in turn would provide more opportunity for the cyber attacks to be successful.

[35] Please refer to Cyber Attack RAMP Risk Model (excel file).

If we eliminate or reduce vulnerability assessments and penetration tests, we would decrease the security capabilities of our IT and OT networks. We would not be able to independently evaluate and proactively remediate technical vulnerabilities that can be exploited by an attacker to compromise SCE assets.

4. Other Considerations

As similarly discussed in the Proposed Plan, if we have not adequately predicted the growing threat, the mitigations laid out in this Alternative Plan #1 may not be sufficient.

B. Alternative Plan #2

SCE evaluated other options to address this risk and developed another alternative mitigation plan, as shown in Table VII-9. The pre- and post-mitigation LoRE, CoRE and risk scores for Alternative Plan #2 are summarized by tranche below in Table VII-10.

Table VII-9
Alternative Plan #2 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[36]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Perimeter Defense	$1.9	$26	1,507
C1 - T2	Perimeter Defense	$2.5	$34	605
C1 - T3	Perimeter Defense	$8.0	$112	2
C2 - T1	Interior Defense	$1.0	$5	1,929
C2 - T2	Interior Defense	$1.4	$7	774
C2 - T3	Interior Defense	$4.5	$22	3
C3 - T1	Data Protection	$1.0	$8	1,917
C3 - T2	Data Protection	$1.3	$10	770
C3 - T3	Data Protection	$4.3	$34	3
C4 - T1	SCADA Cybersecurity	$1.8	$48	138
C4 - T2	SCADA Cybersecurity	$0.6	$16	222
C5 - T1	Grid Mod Cybersecurity	$6.0	$93	71
C5 - T2	Grid Mod Cybersecurity	$2.0	$31	115
Total		**$36.2**	**$446**	**-**

[36] Please refer to Cyber Attack RAMP Risk Model (excel file) and WP. Ch. 7 – Cyber Attack RAMP Financials.

Table VII-10
Pre- and Post-Mitigation LoRE, CoRE and Risk Scores[37]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Cyber Attack	13.4	0.57	7.62	13.4	0.57	7.62
T1 - Bulk Power System	3.7	1.33	4.94	3.7	1.33	4.94
T2 - Distribution System	2.0	1.33	2.65	2.0	1.33	2.65
T3 - Business Operations	7.7	0.004	0.03	7.7	0.004	0.03

1. Overview

Alternative Plan #2 represents the most aggressive approach to expanding our cyber security defenses. This plan expands investing in our defense-in-depth controls (C1 – C5), and moving up the schedule for planned future cyber security projects. In developing this plan, SCE considered global events, political situations, technological advancements, the rapid incorporation of technology into and across our business, and the persistent advancement of threats against our business.

2. Execution Feasibility

While possible, this plan would require a significant operational effort to execute in short order. SCE would have to identify, evaluate, procure, and train a larger number of cyber security experts in a shorter period of time than in the Proposed Plan. This may prove difficult in a cyber security labor market that is already facing resource shortages. In addition, the number of additional, valuable tools that would need to be procured through this plan would require time and coordination to test, install, and deliver across the enterprise.

The cyber security attacks against utilities have been increasing, but we have certain protections in place. As of the RAMP filing deadline, the technology that this accelerated cyber security enhancement applies has not yet reached a sufficiently mature stage where we feel the anticipated benefits outweigh the burdens of technology maturity concerns and performance uncertainties.

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[37] Please refer to Cyber Attack RAMP Risk Model (excel file).

3. Affordability

This is the highest-cost plan that we considered. This plan also provides the greatest scope of work to increase our cyber defenses, and is forecast to reduce the most risk. The risk spend efficiency of this plan is comparable to the Proposed Plan, and higher than Alternative Plan #1. Due to the maturity of the technologies required to deploy this Alternative Plan #2, at this time SCE does not believe the additional expenditures are justified.

4. Other Considerations

As similarly discussed in the Proposed Plan, if we have not predicted the growing threat accurately enough, the activities to mitigate Cyber Attack risks that are set forth in Alternative Plan #2 may not represent the correct fit.

VIII.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

As touched on above, modeling the risk of cyber attacks and the effectiveness of cyber security controls and mitigations was a challenge. In examining asset-based risks, we can evaluate actual failure rates and equipment conditions, and leverage decades worth of utility data and information related to the performance of an asset. In contrast, cyber security does not have a similar breadth of data that we can draw upon when analyzing the risks. In light of the lack of cyber security data and information that is publicly shared, the Risk Spend Efficiency (RSE) parameters in RAMP do not meaningfully capture the manner in which cyber security risk is assessed and mitigated based on the defense-in-depth model.

Additionally, unlike most asset-based risks, cyber attacks are ever-evolving; what we know today may not be applicable to where the threat goes tomorrow, a year from now, or five years from now. As a result, SCE had to leverage whatever limited industry data was available, develop prudent assumptions, and consult with industry experts to validate our approach to this risk evaluation.

During the RAMP process, SCE evaluated the filings from other utilities, and noted that Sempra did not tranche their cyber security risks. Based on discussions with regulatory and internal risk management organizations, our cyber security team identified factors that have allowed us to provide some reasonable degree of tranching for RAMP purposes. Again, due to the difficulty in obtaining industry-focused cyber security metrics and the dearth of meaningful publicly available data, the tranching of the risk is not straightforward.

SCE recognizes that not capturing indirect, or secondary impacts from risk events can underestimate the potential magnitude of a risk. This is especially true for the Cyber Attack RAMP Risk. If a cyber attack were to successfully compromise the grid and cause a widespread and extended blackout, there are likely to be significant secondary safety and financial consequences that would result. These impacts were not able to be captured in this chapter. We look forward to evaluating this issue further, to determine if there is a way to reasonably and credibly incorporate these indirect impacts into future risk reporting.

B. <u>Data Collection and Availability</u>

Most organizations, especially those in the utility and energy sector, are reluctant to share sensitive data on their cyber security operations and defenses, as doing so could broadcast weaknesses and attack vectors to malicious actors. SCE faced two data challenges in this RAMP filing. First, most of the data that we do have relating to our control systems cannot be shared publicly. Doing so would expose our critical systems to attack. As such, the SCE-specific data that we can share as part of this RAMP filing is limited.

Second, to our knowledge, most utility and energy companies follow the same data sensitivity protocols as we do. It can be very difficult to find relevant industry data when most companies understandably do not report (and thereby expose) their vulnerabilities publicly. In cases where breaches are publicly disclosed, typically only the general outcomes relevant to the public are released (e.g., illegal capture of individuals' personally sensitive information). The root cause of the cyber event, the extent to which assets were impacted, details about mitigation, specifics of recovery actions, and associated costs are rarely shared outside of those directly involved with the event. Due to the lack of data sources or standardized information being reported, SCE plans to continue to utilize subject matter experts in cyber security to assist in developing certain RAMP information.

C. Performance Metrics

SCE has a corporate goal around protecting critical infrastructure and customer data. SCE also collects internal cyber security metrics to measure the effectiveness of our cyber security efforts and the threats that we are seeing against our company. Some examples are metrics related to our enterprise phishing exercises, patching, and number of penetration attempts on the network.

In addition, there are several emerging metrics such as utilizing the Department of Energy Electric Sector Cyber Security Capability and Maturity Model (C2M2). This model helps organizations evaluate, prioritize, and improve cyber capabilities. SCE uses a third party security vendor to conduct our C2M2 to compare results on a year-over-year basis. We have started including both IT and OT environments in the C2M2 assessment process.

SCE also leverages BitSight security ratings, which are similar to consumer credit scores, to address cyber risk on the part of supply chain vendors. We also benchmark at a high level with other utilities to compare performance and spend. We will continue to use these metrics as feasible to inform our cyber security plans and strengthen our defense-in-depth capabilities to protect SCE from cyber threats.

IX.

ADDRESSING PARTY FEEDBACK

In reviewing SCE's 2018 RAMP Report, Cal Advocates did provide one recommendation regarding the Cyber Attack chapter in that RAMP.[38] SCE addressed this recommendation in our Test Year 2021 GRC supplemental testimony, and we did not receive any criticism or feedback on our response.[39] At the CPUC-hosted December 6, 2021 SCE RAMP Pre-Filing Workshop, SCE did not receive any feedback concerning the information and preliminary risk scoring that SCE presented on the Cyber Attack risk.

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[38] *See* "Comments of the Public Advocates Office on November 2018 Submission of Southern California Edison Company's Risk Assessment and Mitigation Phase," dated June 14, 2019, I.18-11-006, p. 22.

[39] *See* Exhibit SCE-11 Supplemental Testimony on Risk Informed Strategy & Business Plan, dated April 3, 2020, A.19-08-013, p. 16.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Seismic

Chapter 8

Rosemead CA
May 13, 2022

Chapter 8: Seismic

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I.

EXECUTIVE SUMMARY

A. Risk Overview

Southern California is earthquake country. It encompasses high seismic hazards that have been well-characterized,[1] and that constitute half of the nation's earthquake risk, according to both the United States Geological Survey (USGS)[2] and the Federal Emergency Management Agency (FEMA).[3] (Please refer to Figure I-1 and Figure I-2 below).

Although SCE has made concerted efforts, significant seismic risk remains. Moreover, significant seismic risk will still be present for SCE at the end of this 2025-2028 RAMP interval, even if the Proposed Plan for mitigation is accepted and fully executed. Seismic assessment work is continuing across SCE's many diverse assets, to better measure the vulnerability and exposure to potential seismic-related impacts.

SCE is committed to continuing the prioritized and prudent seismic retrofit of its buildings, emphasizing improved safety as the overarching intent and strategy, while also enhancing system reliability. SCE's approach, through our Seismic Resiliency Program (SRP), is to retrofit certain highly important critical infrastructure buildings and other assets to a more stringent reliability level of seismic retrofit design. By strategically reducing the chance of critical building collapse (or partial collapse), or of red (or yellow) tagging,[4] the SRP should result in an improved level of resiliency of electric service following a seismic event.

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[1] The best available earthquake hazards science for the SCE service area and nearby regions is called the Third Uniform California Earthquake Rupture Forecast (UCERF3); by Field et al. (SRL, 2017) https://pubs.geoscienceworld.org/ssa/srl/article-abstract/88/5/1259/354096/A-Synoptic-View-of-the-Third-Uniform-California?redirectedFrom=fulltext. Further details may be found in the workpapers for this chapter.

[2] *See* https://earthquake.usgs.gov/ - United States Geological Survey earthquake information.

[3] *See* https://www.fema.gov/emergency-managers/risk-management/earthquake - Federal Emergency Management Agency earthquake information.

[4] Building safety assessments and placards, a.k.a. "tags" are as follows: red (Unsafe), yellow (restricted use), and green (inspected). Tags are placed after building inspections, according to ATC-20 procedures and associated training.

In developing the Proposed Plan presented here, SCE has taken into account guidance provided by the latest ATC / NIST-FEMA[5] reports on lifeline system performance, particularly seismic lifeline resilience (also known as functional recovery).[6] During future earthquakes, SCE buildings and critical infrastructure will be exposed to intense shaking, as well as potential ground failures from surface rupture, landslides, and soil liquefaction. It is therefore important to continue SCE's SRP to reduce potential consequences through prioritized mitigation projects. A vital part of the current analysis has been the multi-step assessment process used over the past five years to identify deficiencies relative to established standards,[7] and to quantify the relative fragility of SCE's most critical assets in the event of a major earthquake. We combine that information with site-specific updated calculations of exposure to shaking that can result from a range of scientifically-plausible earthquakes.

We can categorize infrastructure (especially buildings), prioritize efforts, and then design and construct mitigations to strategically reduce risk. In all, 1,180 of SCE's top assets are being analyzed, because they are potentially exposed to the above seismic hazards associated with future earthquakes on the San Andreas Fault, dozens of additional well-characterized faults (such as the San Jacinto, Elsinore, and Newport-Inglewood), and hundreds of less well-characterized yet important faults in the SCE service area. Fortunately, the USGS, FEMA, California Geological Survey (CGS),[8] and other organizations[9] have provided abundant guidance, including detailed codes, standards, and best practices to help SCE mitigate the potential impacts of seismic events. In preparing the current analysis, SCE has been able to leverage the decades-long effort, funded by the National Earthquake Hazards Reduction

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5 *See* https://atcouncil.org/ - Applied Technology Council (ATC) and https://www.nist.gov/ - National Institute of Standards & Technology (NIST).

6 *See* https://nvlpubs.nist.gov/nistpubs/gcr/2016/NIST.GCR.16-917-39.pdf - Critical Assessment of Lifeline System Performance: Understanding Societal Needs in Disaster Recovery and https://www.nehrp.gov/pdf/nistgcr14-917-33.pdf - "Earthquake-Resilient Lifelines: NEHRP Research, Development and Implementation Roadmap."

7 For existing buildings, ASCE 41-17 is used for assessments, as well as FEMA P-154 & FEMA P-58 approaches are used along with the California Building Code as guidance.

8 *See* https://www.conservation.ca.gov/cgs/psha and https://www.conservation.ca.gov/cgs/shp.

9 Institute of Electrical and Electronics Engineers (IEEE) and American Society of Civil Engineers (ASCE).

Program,[10] to improve earthquake hazard knowledge for this region. This effort is led by the Southern California Earthquake Center.[11]

Based on FEMA's 2021 National Risk Index, four of the counties in SCE's service area ranked "Very High" for seismic risk.[12] Los Angeles County was ranked highest in the United States (see Figure I-2, below). Neighboring counties served by SCE also received "Very High" and "Relatively High"[13] scores. Without question, as established by national and state authorities, earthquake hazards and risks are substantial across much of SCE's service area.

In the following analysis, SCE assesses seismic risks to its assets, and proposes a plan to mitigate risks in a prioritized manner.

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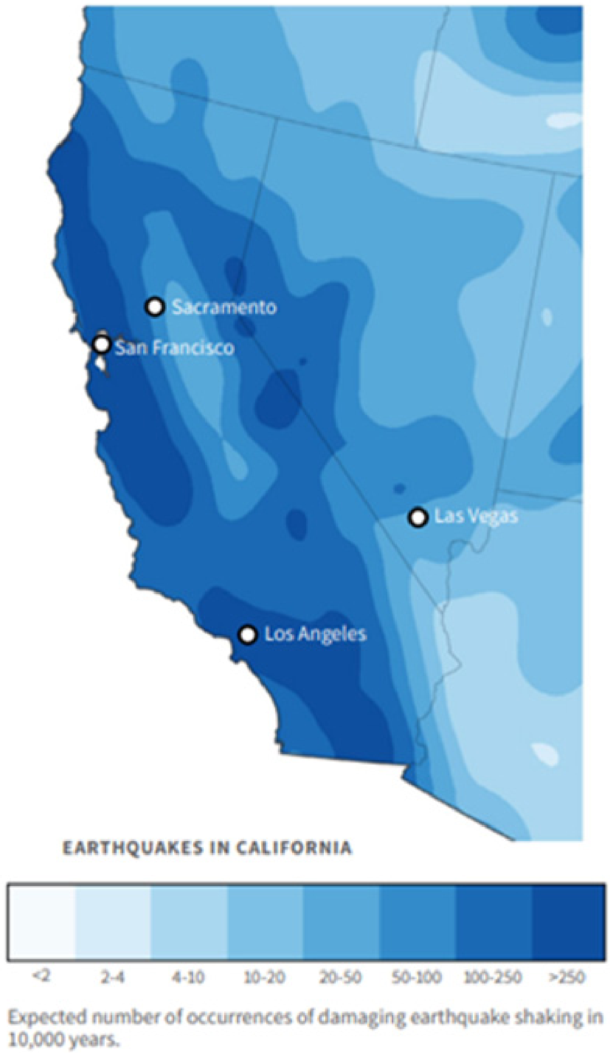
[10] *See* https://www.nehrp.gov/.

[11] *See* https://www.scec.org/ - Southern California Earthquake Center (SCEC) | Studying earthquakes and their effects in California and beyond.

[12] The "Very High"-risk-ranked counties are Los Angeles, San Bernardino, Riverside and Santa Barbara.

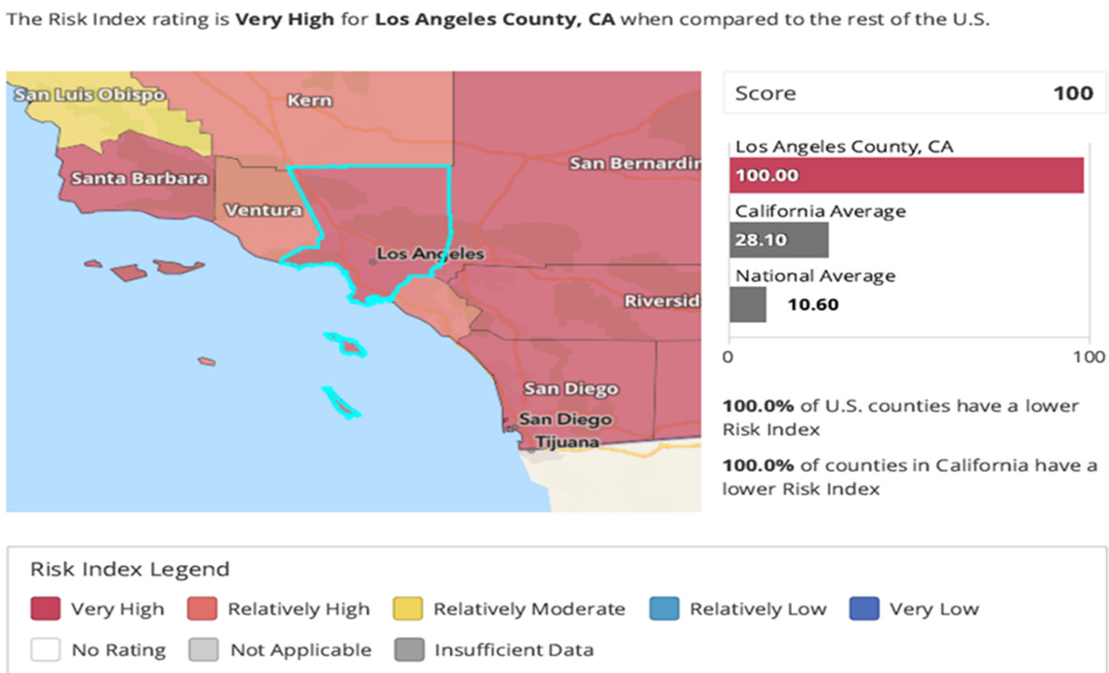
[13] The additional counties risk-ranked "Relatively High" include Orange, Kern and Ventura.

Figure I-1
Earthquake Hazard in California[14]



[14] Map of regional earthquake hazards; source: pp. 91-92, FEMA P-530 (2020) https://www.fema.gov/sites/default/files/2020-08/fema_earthquakes_fema-p-530-earthquake-safety-at-home-march-2020.pdf.

Figure I-2
***FEMA Earthquake Risk in Southern California*[15]**



For this RAMP analysis, SCE leveraged the UCERF3 reports and other existing seismic analyses to estimate potential earthquake frequency, magnitude (M), and strength of shaking[16] at SCE's most critical facilities throughout its service area. The resulting estimates are currently being used to guide the prioritization of mitigation and adaptation measures in our existing SRP. Since the inception of this program in 2016, SCE has assessed 319 facilities and retrofitted 20 buildings. These assessments and retrofits have primarily focused on increasing the ability of the following types of buildings to withstand intense shaking: (a) occupied buildings; (b) large substations; (c) critical computer equipment; and (d) communication facilities.

SCE has also strengthened and secured many of its most important computer and other equipment racks at key facilities, and bolstered the foundations of seven carefully selected transmission

[15] *See* https://hazards.fema.gov/nri/ - Map of multi-hazards risks from FEMA, including seismic.
[16] Refer to WP. Ch. 8 – Earthquake Science.

towers that were deemed vulnerable to landslide damage, possibly in association with seismic shaking. From 2016 through 2021, SCE invested approximately $156.7 million in improving system resiliency.

Programmatically SRP looks at all SCE infrastructure, including administrative buildings. In light of RAMP's emphasis on public safety, the risk scoring below and in this Chapter will focus on infrastructure and mitigations being executed to support reliability of service and public safety. Thus, the Seismic analysis in this RAMP chapter does not focus on our seismic retrofits of occupied SCE buildings, which are a vital safety mitigation for SCE personnel who work in those buildings. In our Test Year 2025 GRC application, we will include analysis that incorporates that worker safety component. When worker safety is included, the RSE scores for seismic retrofit mitigations increase.

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Seismic risk.[17]

Table I-1
Summary of Pre- and Post- LORE and CORE Risk Scores[18]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			**Post-Mitigation Risk Quantification Scores (End of 2028)**		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Seismic	0.17	19	3.2	0.17	18	3.0

II.

RISK ASSESSMENT

A. Risk Definition and Scope

The scope of this risk chapter is defined in Table II-2 below.

17 LoRE – likelihood of risk event. CoRE – consequence of risk event. Risk Score is the product of the LoRE and CoRE. For additional information on the risk modeling methodology, please refer to Chapter 2 – Risk Model and Methodology.

18 Please refer to Seismic RAMP Risk Model (excel file).

Table II-2
Scope for SCE's 2022 Seismic RAMP analysis

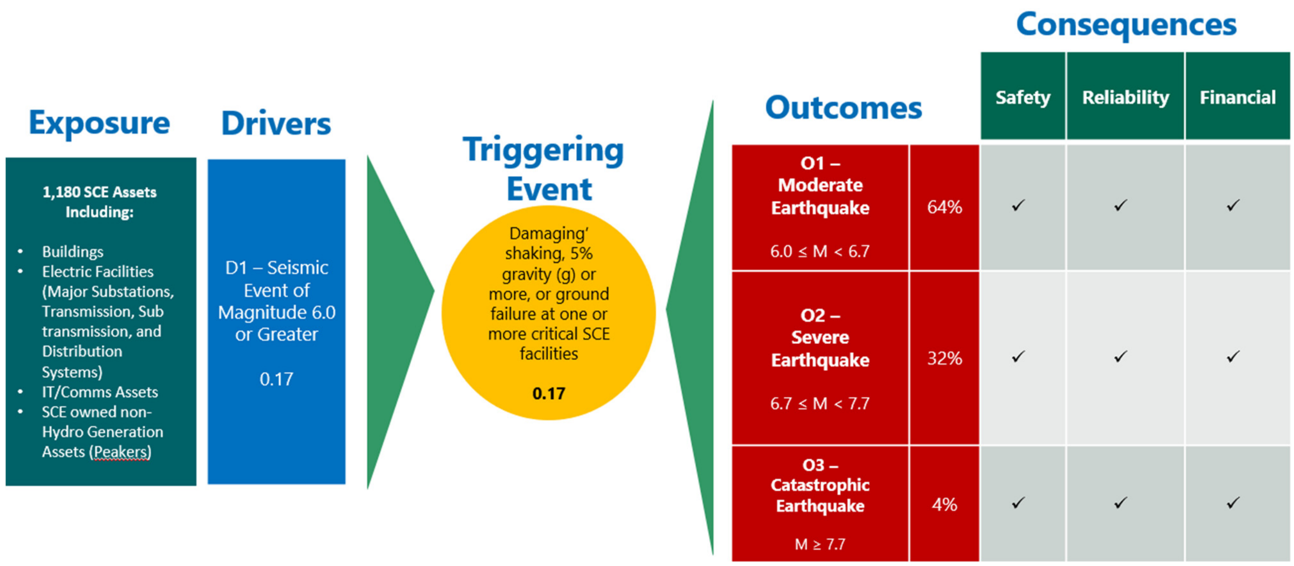
In Scope	The 107 most critical assets, combined across electric, generation and IT/comm workstreams, considering both safety and reliability performance objectives. This asset list is separated into two tranches. Tranche 1 has 19 assets, and Tranche 2 has 88 assets. The top 107 assets were included in updated safety scoring. Scoring includes occupied and unoccupied buildings housing 8 & 24 hour RTO essential and critical processes. Tranche 1 includes all data centers, GMC's, and DOC's. Tranche 2 includes the remaining switching centers, bulk substations, plus selected key blackstart generation and communications facilities and service centers. Tranche 3 encompasses 1,073 assets that are classified as less critical (distribution substations and next-tier-down IT/Comm and Generation assets); these assets are still deemed very important, and are considered for prioritized damage assessment in the event of a major seismic incident.
Out of Scope	Tranche 4 is not included in the RAMP analysis but is included in the SCE Seismic Resiliency Program, which also considers seismic risk for SCE's transmission corridors & towers and distribution lines & poles, as well as all other SCE assets across all workstreams.

B. <u>Risk Bowtie</u>

To evaluate the seismic risk to SCE's system, SCE constructed a risk bowtie as shown in Figure II-3. The bowtie presents the risk driver, outcomes, and consequences of seismic risk with additional detail on each of these components provided in the sections below. SCE has defined the exposure of seismic risk to encompass all 1,180 critical assets.[19] The bowtie presented below closely resembles the bowtie presented in SCE's 2018 RAMP report. The most notable difference is the exposure in the 2022 RAMP bowtie has been expanded to include a wider range of facilities, rather than primarily focusing on SCE-occupied buildings. In addition, because of the greater diversity of structures and more widespread geographic locations found in the much longer list of facilities and assets, SCE revised its analysis for the more comprehensive 2022 RAMP. Additionally, SCE included an additional outcome and more refined consequences to better represent these outcome scenarios.

[19] Refer to Section II.F for additional detail on SCE's tranching approach.

Figure II-3
Risk Bowtie for Seismic Risk[20]



C. Drivers

For purposes of this RAMP analysis, SCE identified one driver, a seismic event of magnitude 6.0 or greater. SCE chose this threshold as a result of design specifications employed, and based on the past several decades of actual performance. Experience has shown that SCE infrastructure can, in some cases, already be resilient to some extent to seismic events of less than 6.0 in magnitude, and even up to magnitude 7.0, as long as they occur in remote parts of the service area. SCE's SRP targets sites of concern in areas with the greatest concentrations of assets. This tends to be the urban parts of the service area. With the exception of the 1994 Northridge M 6.7 event, in recent decades our region's highly complex and interconnected urban infrastructure resilience has not been tested by real-world events in the severe and catastrophic outcome categories.

1. D1 – Seismic Event of Magnitude 6.0 or Greater

The probability of a seismic event of M 6.0 or greater is considered as the driver because an event of this size can cause significant damage to critical assets, even ones that have been mitigated to meet the current standard of the American Society of Civil Engineers (ASCE) for retrofitting existing

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[20] Please refer to WP. Ch. 8 –Baseline and Risk Inputs.

buildings.[21] The driver value has been modified since the 2018 RAMP filing. The driver value of 0.17 represents the newly-revised[22] probability that is appropriate for the currently-estimated exposure of SCE assets. The driver frequency was 0.33 in 2018, but is now 0.17, reflecting certain changes in geographic locations of the variety of exposed assets we are considering in our risk analysis.

D. Triggering Event

As described in Section I, the seismic risk in the SCE service area has been well-quantified, and the uncertainties are reasonably well-understood, published, and made available through the Working Group on Conditional Earthquake Probabilities (WGCEP). The latest model is the Uniform California Earthquake Rupture Forecast, Version 3 (UCERF3).[23] Approximately half of the seismic risk in Southern California is associated with the San Andreas Fault, while the other half is from other faults in the region. These other faults include the San Jacinto Fault, the Elsinore-Whittier Fault, and the Palos Verdes, Newport-Inglewood, Puente Hills Thrust, Raymond and Santa Monica – Hollywood faults, as well as the blind thrust fault[24] system that underlies the metropolitan Los Angeles area. These other faults are also very important to consider with respect to potential impacts to SCE electric infrastructure.

The RAMP seismic analysis considers a wide variety of potential earthquake sources, simplified for presentation purposes to a single statement of frequency of triggering event.

E. Outcomes and Consequences

SCE considered three discrete ranges of outcomes, including moderate, severe and catastrophic earthquakes.[25] SCE recognizes that this necessary simplification of outcomes does not account for the

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[21] Please refer to ASCE Standard 41.

[22] Please refer to WP. Ch. 8 - "Risk Driver Annual Occurrence Rates and Outcomes." This workpaper provides details regarding the driver frequencies, and allocation by tranche and by the outcome categories 'moderate,' 'severe,' and 'catastrophic.'

[23] *See* image – ref: http://wgcep.org/UCERF3.html.

[24] The term "blind" means that the fault does not reach to the ground surface. Thrust faults accommodate crustal convergence, lifting one side up and over the other. In the Los Angeles region, these "blind thrust faults" underly much of the metropolitan area. The 1987 Whittier Narrows and 1994 Northridge earthquakes occurred on blind thrust faults. The earthquake science workpaper accompanying this chapter describes the situation in greater detail.

[25] Definitions for this analysis: 1) 'Moderate' earthquakes with magnitudes $6.0 \leq M < 6.7$; 2) 'Severe' earthquakes with magnitudes $6.7 \leq M < 7.7$; and 3) 'Catastrophic' earthquakes with magnitudes $M \geq 7.7$.

variability in all possible earthquake sources. As noted in previous sections, the Los Angeles Basin represents a high concentration of seismic risk. Small seismic events in this region can produce significant impacts, while larger seismic events outside of this region may yield only minor impacts.

For example, the 1933 Long Beach, 1971 San Fernando and 1994 Northridge earthquakes were magnitude 6.0 or greater earthquakes within the Los Angeles Basin. All of these earthquakes caused significant damage to SCE and Los Angeles Department of Water and Power (LADWP) infrastructure. In contrast, the 1992 Landers, 1999 Hector Mine, and 2019 Ridgecrest earthquakes, which were magnitude 7 or greater earthquakes outside of the Los Angeles Basin, caused only minor damage to SCE infrastructure. For this analysis, SCE has selected one representative earthquake scenario for each range of possible outcomes.[26]

An important caveat is that, in part, the limited SCE historical earthquake consequences have been fortuitous; but they are also to a degree the result of earlier SCE attention to engineering standards and seismic-resilient design and mitigation efforts. The 1971 and 1994 earthquakes primarily impacted the LADWP service area; the 1992 earthquake was in a remote desert area; and the heaviest damage from the 1999 and 2019 earthquakes was confined to the Marine Corps and Navy military bases plus adjacent remote desert areas. Thus, SCE infrastructure remained reasonably resilient with relatively limited disruption of service to its customers from those historical events.

In SCE's analysis of the potential impacts of future severe and catastrophic earthquakes, scientifically plausible yet unprecedented events are included through the use of specific earthquake scenarios. This approach is widely accepted in the seismic field. From a combination of probabilistic and scenario-based depictions and models of expected consequences, SCE develops insights into how to prioritize seismic retrofit projects, and works to anticipate and minimize damage from future events that may exceed historical precedents.

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[26] Please refer to WP. Ch.8 – Safety, Financial, and Outage Impacts of Three Earthquakes.

1. Outcome 1: Moderate Earthquake (64%)

SCE categorizes moderate earthquakes as those between magnitude 6.0 and magnitude 6.7. Within the Los Angeles Basin, most SCE facilities are likely to be moderately impacted, while at least one SCE critical infrastructure facility could be significantly impacted. Of the total number of earthquakes greater than 6.0, moderate earthquakes represent 64 percent of the total possible outcomes.

Moderate earthquakes within the Los Angeles Basin, along the Newport-Inglewood, Raymond, Puente Hills, or Elsinore-Whittier faults, would likely moderately impact several SCE facilities, but could significantly impact at least one critical facility. Given the possibility that a moderate impact may heavily impact more than one critical asset, SCE's SRP considers moderate events.

While moderate earthquakes outside of the Los Angeles Basin may not significantly impact the majority of SCE facilities, they could potentially significantly impact one or more critical facilities, particularly transmission assets designed to deliver bulk power to the greater Los Angeles Basin. One example is the 1986 North Palm Springs earthquake (M 6.0), which was located 4.5 miles away from an SCE substation at a depth of 6 miles. This earthquake displaced a large transformer and led to the development of additional standards to improve the anchoring of material within SCE bulk substations.

Modeled consequences for moderate earthquakes (O1) are generally less than severe, and can be managed by SCE with restoration of service expected within several days, and without the need to resort to mutual assistance. One example of a moderate scenario is a M 6.0 on the Raymond Fault, which would be expected to result in 0 fatalities, 30 injuries, 0.12 billion CMI[27] (within SCE's control), and $22 million in direct financial impact.[28] The most recent earthquake in the SCE service area in this category was the magnitude 6.4 event on July 4, 2019. This event proved to have a negligible impact on SCE assets.

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27 CMI refers to customer minutes of interruption.

28 Please refer to WP. Ch. 8 - Safety, Financial, and Outage Impacts of Three Earthquakes.

2. Outcome 2: Severe Earthquake (32%)

SCE categorizes earthquakes between magnitude 6.7 to 7.7 as severe earthquakes. This category includes a wide range of possible events. Some of the events may result in minor damage, while others may result in significant safety and reliability impacts. For example, the 1992 Landers (M 7.3), 1999 Hector Mine (M 7.1) and 2019 Ridgecrest (M 7.1) events, all of which were located outside of the Los Angeles Basin, did not cause significant damage to SCE facilities. In large part, SCE infrastructure was undamaged due to the remote nature of these events. More importantly, SCE infrastructure and overall system reliability risk were mitigated by prudent redundancies in the data center, switching operations, and bulk electric system itself. For instance, in the 1994 Northridge earthquake (M 6.7), SCE was able to bypass a single substation to rapidly restore and then maintain service until the substation could be repaired.

For this outcome, SCE used a proxy magnitude 6.8 event on the Raymond Fault.[29] This earthquake scenario simulates a fault within the Los Angeles Basin that would potentially have severe impacts on SCE infrastructure. This one example of a severe earthquake scenario would be expected to result in 1 fatality, 35 non-fatal injuries, 1.2 billion CMI (within SCE's control), and $55 million in direct financial impact.[30]

3. Outcome 3: Catastrophic Earthquake (4%)

Earthquakes with intensity greater than magnitude 7.7 are considered "catastrophic." These earthquakes have the potential to simultaneously impact several critical SCE assets. While these types of catastrophic earthquakes are less frequent than moderate or severe events, they are the primary focus of SCE's SRP, due to the significant safety and reliability consequences which would likely result from such an event.

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29 Please refer to WP. Ch. 8 – Safety, Financial, and Outage Impacts of Three Earthquakes.
30 Please refer to WP. Ch. 8 - Safety, Financial, and Outage Impacts of Three Earthquakes.

SCE used the San Andreas Fault (M 7.8) "ShakeOut" scenario[31] to simulate potential consequences for this outcome scenario. The resulting modeled consequences for this scenario are:

1. *Safety* – Fatalities and Serious Injuries (in SCE buildings). Consequences calculated are 1 fatality and 35 serious injuries within SCE's buildings.[32]

2. *Reliability* – Widespread Outage (due to SCE facility/asset system impacts). Consequences would result in a total of approximately 160 billion CMI, or an average of 22 days per customer. Only approximately a one-fifth portion of that CMI total is considered to be within the control of SCE; the other four-fifths of the CMI total reside in externalities and third-party interdependencies, all of which are uncertain. SCE's approach is to reduce the risks it can reasonably mitigate through the Proposed Plan, and to take other actions, such as coordinating with counterparts at other investor-owned utilities (IOUs) to cumulatively help to reduce the CMI total.[33] See Figure II-4 below. A workpaper[34] provides further details on the basis for this estimate.

3. *Financial* - SCE estimates $110 million in direct losses, based on building damage studies published by established sources.[35] These studies have estimated that the entire regional financial impact of the ShakeOut scenario, including fires following the earthquake, could exceed $213 billion.

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31 https://www.usgs.gov/programs/science-application-for-risk-reduction/science/shakeout-earthquake-scenario and https://pubs.er.usgs.gov/publication/ofr20081150. As discussed above, our RAMP analysis focuses on public safety, and thus the injury and fatality figures provided do not encompass SCE's occupied buildings such as our General Offices.

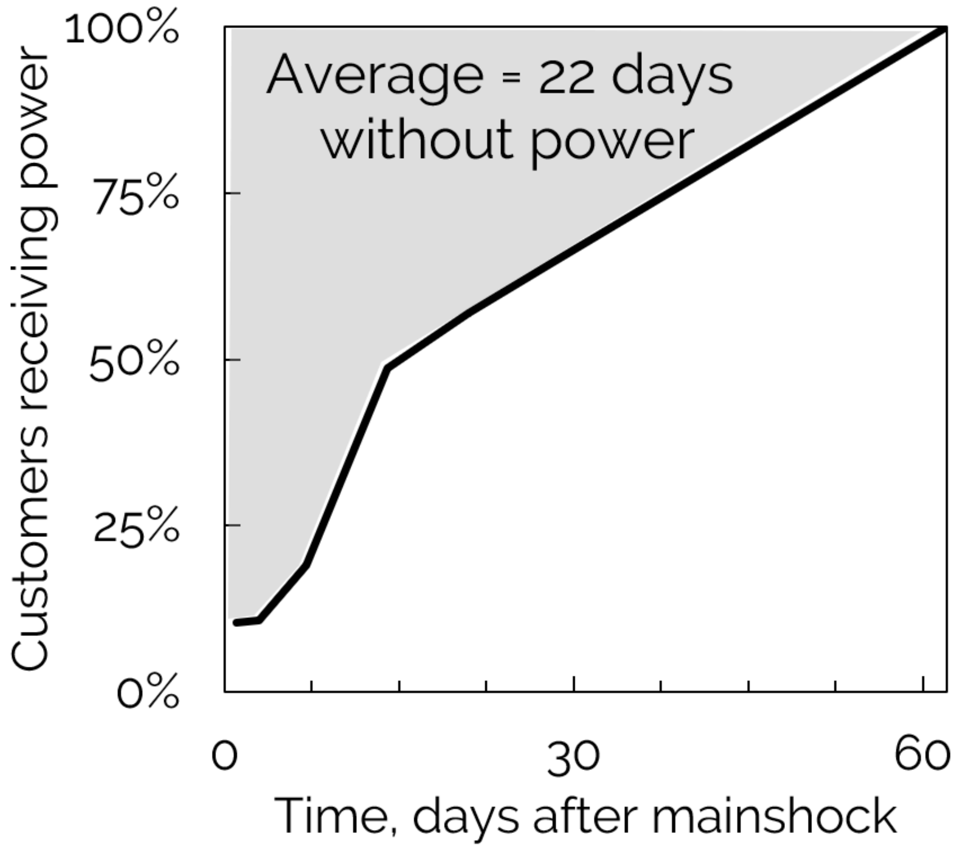
32 In Feb. 2019, FEMA P-154 assessments were completed for 319 of SCE's buildings, both occupied and unoccupied. As of early 2022, over 57 SCE occupied and unoccupied buildings have been further assessed using the ASCE 41 method, up through at least tier 1. Selected highly occupied buildings, and buildings that house essential and critical processes, have been assessed to ASCE 41 tier 2 and in a few cases, to tier 3. Retrofits have been completed for 27 buildings, providing significantly reduced seismic safety risk for 2,736 seated SCE employees as of April 2022. In several cases, as an alternative to seismic retrofitting, SCE has instead vacated and/or re-purposed buildings to reduce seismic risks.

33 Such coordination includes joint planning, and mutual aid arrangements. As appropriate, SCE has at times met with the Los Angeles Department of Water and Power for seismic coordination and discussion purposes.

34 Please see WP. Ch. 8 Widespread Power Outage and Restoration in a Catastrophic Southern California Earthquake.

35 The main Wein & Rose and Rose, Wei & Wein contributions to the ShakeOut body of work may be found as follows: https://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.460.1507&rep=rep1&type=pdf; https://pubs.er.usgs.gov/publication/70034165 and https://journals.sagepub.com/doi/10.1193/1.3587204.

Figure II-4
Estimated Service Restoration Times for M 7.8 San Andreas Fault Earthquake Scenario ("ShakeOut")[36]



F. Tranches

SCE tranched the facilities exposed to seismic risk based on two criteria: 1) S*afety.* In light of the RAMP analysis's stated focus on public safety, this criteria means the safety associated with service continuity; 2) *Reliability.* This means the reliability of SCE assets that house essential and critical processes to help ensure safe and reliable service to our customers.

[36] Estimated service restoration times were developed during an internal SCE workshop held on December 29, 2021, and several follow-up meetings with subject matter experts. The workshop and meetings were used to estimate the widespread outage potential, given the single catastrophic earthquake scenario, and use a structured method to arrive at a single realistic realization of restoration curves. Please refer to our workpaper titled "Widespread power outage and restoration in a catastrophic southern California earthquake; 2021-12-5" which shows the basis for estimates used in the calculations for reliability consequences.

The safety and reliability scores of these facilities were combined into a Criticality of Asset (CoA) index.[37] SCE has employed the CoA index to categorize buildings into four tranches, as described below. We used Tranches 1, 2, and 3 for the RAMP calculations. Please also refer to Figure II-5 for an illustration of the tranches.

- Tranche 1) CoA index 1.0-1.3, 19 assets and facilities. This tranche includes SCE's most critical assets, such as data centers, regional operational centers, primary blackstart generation assets, and communication hubs.
- Tranche 2) CoA index 1.4-2.9, 88 assets and facilities. This tranche is comprised of other critical assets, including switching centers, service centers, bulk substations, and secondary blackstart assets.
- Tranche 3) CoA index 3.0-5.0, 1,073 assets and facilities. This tranche is comprised of highly important assets, namely redundant communications facilities, distribution substations, and other generation assets.
- Tranche 4) Tranche 4 is composed of other critical facilities including but not limited to transmission corridors, lattice towers, and other major facilities.

For the top two tranches combined, SCE performed safety scoring calculations for 107 assets and facilities out of the 1,180 in our active list in the first three tranches. While SCE's SRP also considers Tranche 4 – the base of the SCE "Seismic Resiliency Pyramid" – SCE did not consider these important assets[38] to be within the scope of the current RAMP analysis.

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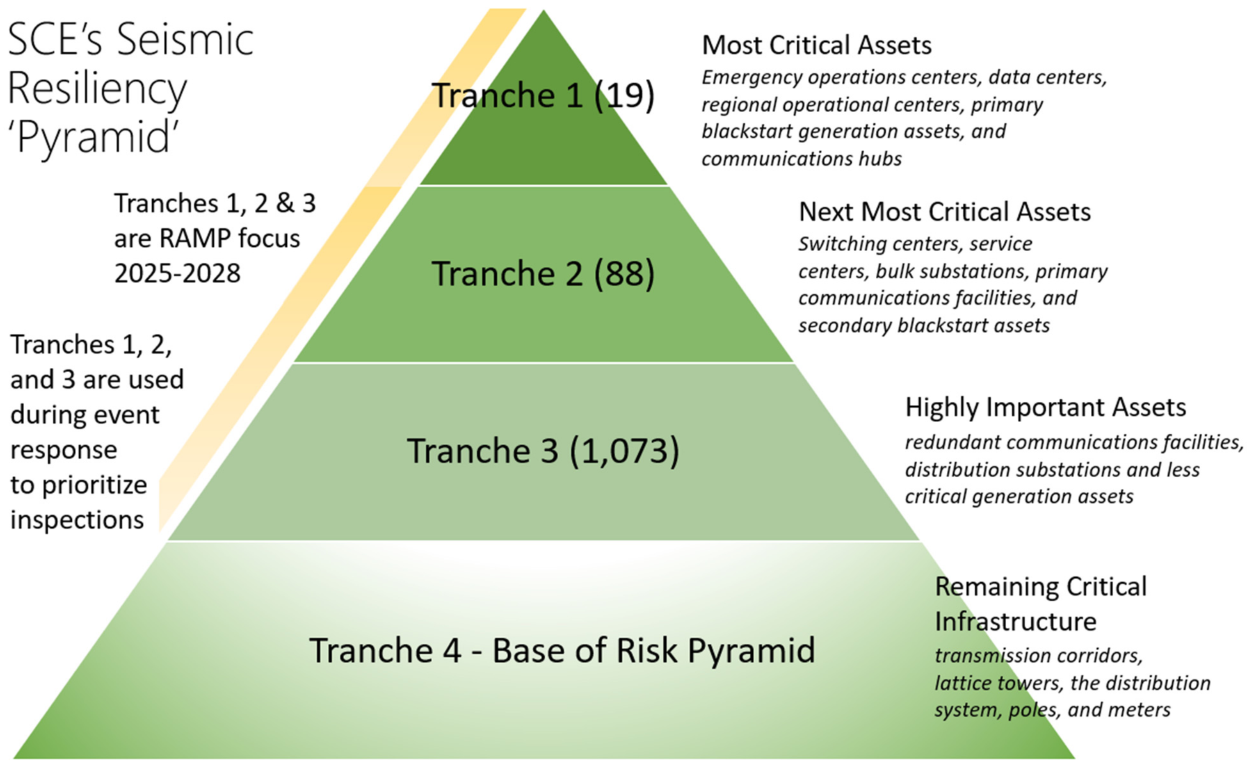
[37] Most notably ASCE 41 for buildings and IEEE 693 for switchyards.

[38] The SCE Proposed Plan does include continued efforts to assess and mitigate carefully selected single assets within tranche 4 as needed during the RAMP interval, such as continuing to identify and mitigate certain transmission towers with potential landslide-vulnerable foundations. The sustainable rate of these projects is currently strongly limited by external factors such as permitting and other access issues. The SCE towers tend to be on easements rather than on SCE-owned lands. So in order to move the required heavy equipment, it is often necessary to obtain permission and make access road repairs of wash-outs on remote and little-used roads that are not owned by SCE. The SCE Proposed Plan includes continuing the strategic spares program, which is considering adding capacity to more rapidly repair more towers rapidly, so as to restore transmission corridor functions sooner.

Figure II-5
SCE's Seismic Resiliency Pyramid



G. Related Factors

A significant related factor in reducing the duration of a widespread outage is blackstart capability. It is possible that a major earthquake may require system blackstart. The topic of blackstart has been actively considered by SCE's SRP. It was most recently discussed during a December 29, 2021 widespread outage internal workshop. The output of this workshop is summarized in a workpaper.[39]

[39] Please refer to WP. Ch. 8 Widespread Power Outage and Restoration in a Catastrophic Southern California Earthquake.

III.

CONTROLS

SCE has identified four controls that are included in the risk analysis.[40] These are shown in Table III-3 below.

Table III-3
Inventory of Seismic Risk Controls

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
C1	Seismic Building Safety Program – Electric	-	O1, O2, O3	Safety, Reliability and Financial	No	All
C2	Seismic Building Safety Program – IT Telecom	-	O1, O2, O3	Safety, Reliability and Financial	No	All
C3	Seismic Building Safety Program – Generation	-	O1, O2, O3	Safety, Reliability and Financial	No	All
C4	Emergency Management	-	O1, O2, O3	Safety, Reliability and Financial	Yes	All

A. C1 Seismic Resiliency Program – Electric

SCE continues the switchyard fragility improvements at transmission substations, nearing completion as of Q1 2022. Next, SCE plans to start work on seismic retrofits of reliability-prioritized unoccupied buildings at substations. The switchyard program has included work such as changing suspended coupling capacitor voltage transformers to seismically qualified pedestal-mounted configurations, reconductoring to add slack between components, improving anchorage of power transformers and station light and power transformers, and upgrading 500kv and 220kv bus jumpers.

[40] C = Control. This is an activity performed prior to or during 2022 to address the risk, and which may continue through the RAMP period.

For 2025-2028, the workstreams will continue to also include transmission line seismic mitigation and continuing assessment of transmission lines. Mitigation of geotechnical hazards such as liquefaction and landslides where assessment has determined a need[41] will continue.

Installing building seismic retrofits at transmission substation Mechanical and Electrical Equipment Room (MEER) structures (see Figure III-6) and assessing MEER buildings using ASCE 41 standards will also continue. Typically, these MEER building walls are strengthened to greatly reduce potential for inward and outward deflections of the walls, and the walls are attached better to the roof. These are two of the main conditions that could result in partial collapse of these buildings, if they were left unmitigated. The average construction date of the bulk substation MEERs that remain to be retrofitted is 1956; the oldest is 1914 and newest is 1973. Most are tiltup concrete or reinforced masonry with flexible diaphragms,[42] and for risk category IV retrofit we use a NIST model to estimate an average cost of $143 per square foot.

Within Control 1, Tranche 1, SCE has further prioritized retrofits so that several of the largest and most complex critical facilities are planned to be retrofitted sooner in the Proposed Plan compared to the Alternative Plans. During these retrofits in data centers, it is imperative that dust from active construction is kept out of sensitive computer equipment in order to ensure operational continuity. This adds to the complexity of the retrofit, and therefore increases the cost per retrofit.

Overall, the cost per retrofit decreases with time once those higher-cost and more complex projects on the larger buildings have all been completed. This is due to the fact that costs are largely based on square footage, as well as the age of the building and complexity of the retrofit. In turn, the resulting RSEs for Control 1, Tranche 1 in the Proposed Plan appear lower than Alternative Plans #1 and #2 because total costs would be lower in the Alternatives, and individual retrofit costs would be spread

[41] The CGS maps available through EQZapp show potential soil liquefaction & landslide areas, and these items typically trigger recommendations to perform site-specific initial geotechnical investigations during the ASCE 41 process. If a site is shown to have low potential for these hazards, recommendations will be prepared and a risk acceptance decision may be made by SCE leadership. If significant potential for these hazards exists at a site, either mitigation activity or further study may be performed.

[42] The bulk substation MEERs are PC1 or RM1 FEMA building types, and average 8,373 square feet and range from <1,00 square feet to >12,000 square feet. Risk category IV, importance factor 1.5 retrofits are being performed with a goal of immediate occupancy to enhance resiliency and reliability.

over a longer interval in the Alternatives. Due to the criticality of these buildings, it is important that the identified high-priority, high-risk retrofits be completed as soon as possible, as outlined in the Proposed Plan.

Figure III-6
Completed Seismic Retrofit of a Reinforced Masonry Wall at an SCE AA Substation; Vertical Pipes Added and Ties from Walls to Roof Added

The work for the MEER retrofit work will help bring the risk of building collapse to a level equal to that of current substation design standards. The work scope from previous GRCs will change as shown in the scope and financial calculations, and there will be a continued emphasis on MEER building seismic retrofit work.

1. **Drivers Impacted**

This control does not impact the driver frequency of a seismic event.

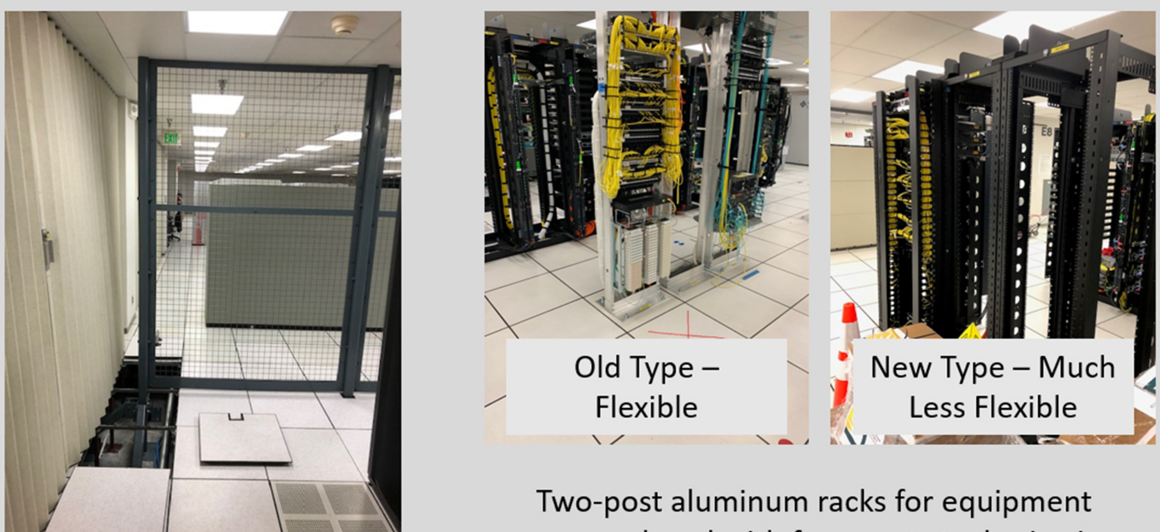
2. **Outcomes and Consequences Impacted**

By improving the resiliency of substation equipment and buildings, as well as foundations of selected critical transmission towers, SCE is reducing the likelihood of equipment failure due to damage from an earthquake. Accordingly, SCE is lessening the duration and extent of electrical disruption that could otherwise occur in association with future earthquakes. The SRP for electric infrastructure would improve reliability, reduce the effects of widespread outage, and reduce the direct financial impacts of earthquakes by reducing the need for repairs after a seismic event.

B. C2 – Seismic Resiliency Program – IT Telecom

Most IT/Comm facilities are co-located with SCE's occupied buildings or substations, and their inspections are included in coordinated plans. Over 140 hilltop and mountaintop remote sites are also part of the IT/Comm inventory, many of which are normally reached by roads that may potentially be imperiled by earthquake-triggered landslides. SCE is developing plans to improve response and readiness to perform aerial inspections and remote sensing to assess damage to these remote facilities and their access roads. Within SCE's critical facilities, computers and related equipment are housed in racks. Also, equipment that is awaiting installation is stored in work areas that need to be kept secure. In case of shaking associated with earthquakes, any unsecured equipment must be kept from hitting racks. For these reasons, SCE has been mitigating existing racks that are two-posted and also, in select cases, replacing two-post racks with seismically qualified four-post racks (see Figure III-7).

Figure III-7
Completed Seismic Mitigations at an SCE Data Center;
Seismic-Qualified Fencing Added and Computer Equipment Racks Replaced



Seismic-qualified fencing was needed to secure palletized new equipment prior to installation

Two-post aluminum racks for equipment were replaced with four-post steel seismic-qualified racks to secure critical computers. (in other cases, two-post racks are mitigated by strengthening instead of replacing them)

1. **Drivers Impacted**

This control does not impact the driver frequency of a seismic event.

2. **Outcomes and Consequences Impacted**

Mitigating IT/Comm racks and equipment before future seismic events -- by bracing and strengthening racks -- will lead to the outcome of reduced or avoided damage to these facilities.

C. C3 – Seismic Resiliency Program – Generation

The Tranche 1 Generation assets include those required to perform a successful blackstart in the event of a major earthquake. As such, strengthening by adding engineered bracing retrofits is expected to reduce potential damage to these facilities. This should facilitate their return to service after a major earthquake to help restore service to the grid. SCE has also continued to work with CAISO on geohazard considerations in the context of additional blackstart-qualified assets. This is to improve the probability of rapid blackstart success in case of need.

1. **Drivers Impacted**

This control does not impact the driver frequency of a seismic event.

2. **Outcomes and Consequences Impacted**

By mitigating generation assets and continuing to work in support of CAISO-driven system improvements, SCE anticipates being in a better position to perform a successful blackstart if necessary after future major earthquakes. The widespread outage consequence of a catastrophic earthquake, for example, could be reduced by several days if these mitigations are implemented successfully.

D. C4 – Emergency Management

SCE maintains an all-hazards Emergency Preparedness program that includes development of emergency response plans, as well as an Emergency Operations Center and associated roster of qualified personnel, along with a training and exercise program, to maintain readiness of Incident Response Teams to respond to earthquakes. In 2020, the SCE-wide full-scale exercise was conducted successfully, based on a “catastrophic” earthquake scenario. Again, in 2022, the SCE-wide full-scale exercise will be based on a simulated “catastrophic” earthquake. In addition, a series of nine proof-of-concept drills are in the process of being executed at this time, each of which is being based on "severe" earthquake scenarios.

SCE also maintains a Business Continuity Program with ongoing development, testing and refinement of Business Continuity Plans to be able to continue essential and critical processes and business functions following disruptive events like moderate, severe or catastrophic earthquakes. On an ongoing basis, SCE participates in various external engagement activities with the objectives of improving mutual aid agreements and overall interconnectivity of critical infrastructure.

With support from California Energy Commission's (CEC) Electric Program Investment Charge Program (EPIC) III[43] program, SCE entered into a contract for developing new software to be used in conjunction with existing platforms to improve strategic prioritization of mitigation activities, and for use during real-world event response.[44] After demonstration and delivery of the Advanced Comprehensive Hazard (CHaT) product, SCE will consider steps for internal implementation. In this Proposed Plan, SCE considers this work as part of the C4 control. Work will entail structuring the necessary level of effort around the operational implementation of the CHaT product. Data and system security compliance will be required for introducing the new software, setting it up and testing it, and then ensuring system safety during future operational use.

SCE also has a standing contract to support the need for additional qualified building inspectors following an earthquake, and during the aftershock sequence. SCE employees have received training in post-earthquake initial damage inspection and reporting. The employees are qualified to perform initial safety inspections, as well as to document damage and place the associated initial SCE red, yellow, or green tag onto SCE buildings as a temporary measure until other building inspectors are able to reach the location later. This training and exercise program is being refined and tested on an ongoing basis in 2022, and should continue to improve.

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[43] *See* https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program.

[44] Although the CHaT tools will address multiple hazards, the SRP will benefit directly from the seismic module. Several use cases in the work plan address identified gaps between existing solutions.

SCE is also in the process of developing new remote-sensing methods and leveraging aerial inspection assets for potential use in rapid damage assessments. These methods could potentially be employed after a catastrophic earthquake.

1. Drivers Impacted

This control does not impact the driver frequency of a seismic event.

2. Outcomes and Consequences Impacted

This control affects reliability by assisting in better prioritization of 1) mitigation projects to reduce consequences, as well as 2) post-earthquake repairs to enable service to be restored more expeditiously. The prioritized seismic retrofit of buildings is expected to reduce the risk of collapse for SCE assets from very high, high, or elevated to much lower -- but not to zero. Even after retrofitting, especially if design levels are exceeded, impacts may occur and require response, recovery and restoration actions. In the event of a damaging earthquake, information forms completed by field personnel are sent to the Emergency Operations Center (EOC) where the data is compiled and evaluated. These data sets are an important part of developing and maintaining situational awareness to enable better-informed decision making at the EOC.

By ensuring that personnel are trained and equipped, this program ensures more timely assistance to any injured or trapped personnel within any damaged buildings, as well as ensuring more targeted deployment of potentially limited numbers of qualified inspectors. These on-site personnel are capable of greatly reducing the time to restore electrical service to customers through their knowledgeable and safe conduct of their responsibilities in the aftermath of a severe or catastrophic earthquake. Continuity of this program is necessary to ensure that knowledge is retained and passed on to new personnel over time, and that on-site emergency supplies are kept current and available.

IV.

MITIGATIONS

During the development of this RAMP report, SCE has not proposed more effective new ways to mitigate seismic risk, in addition to the existing controls. Any new approaches tend to be unique solutions, smaller in scope, or modifications or enhancements to the controls listed above in Section III.

One recent example is considering and developing a set of options to provide backup generator and uninterruptable power supply at a unique short-term leased facility. We did not feel -- although such important matters arise frequently -- that such improvements and refinements rise to the level that should be considered separate mitigations for our Alternative Plans. A more detailed discussion on the Alternative Plans is discussed in Section VII.

V.

FOUNDATIONAL ACTIVITIES

We assess SCE facilities on an ongoing basis to identify and then further characterize residual seismic risks, such as structural (ASCE 41) and non-structural (FEMA E-74) deficiencies. The costs of these assessments are included in the Control cost estimates, and SCE considers the assessment effort to be a foundational activity that is essential to SCE's understanding of its seismic risk. Desktop and field studies are performed for large numbers of smaller un-occupied buildings that house important equipment, and along the most important transmission corridors (*e.g.*, those with roles as blackstart or intertie lines). Support of this ongoing activity needs to continue because, although significant progress has been made, hundreds more facilities and assets remain to be assessed.

VI.

PROPOSED PLAN

SCE has developed a Proposed Plan to mitigate Seismic risk, as shown in Table VI-4 below. The pre- and post-LoRE, CoRE and risk scores for the Proposed Plan is summarized by tranche below in Table VI-5.[45]

[45] Please refer to Seismic RAMP Risk Model (excel file) and WP. Ch. 8 – Seismic RAMP Financials.

Table VI-4
Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[46]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Seismic Building Safety Program – Electric	$0.2	$80.0	369
C1 - T2	Seismic Building Safety Program – Electric	$0.1	$32.0	148
C1 - T3	Seismic Building Safety Program – Electric	$0.2	$64.0	13
C2 - T1	Seismic Building Safety Program – IT Telecom	-	$10.0	1,494
C2 - T2	Seismic Building Safety Program – IT Telecom	-	$8.8	136
C3 - T1	Seismic Building Safety Program – Generation	-	$4.8	1,556
C4 - T1	Facility Emergency Management Program	$0.4	-	15
C4 - T2	Facility Emergency Management Program	$0.4	-	28
Total		**$1.3**	**$199.6**	**-**

Table VI-5
Pre- and Post- LoRE, CoRE and Risk Scores[47]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Seismic	0.17	18.86	3.21	0.17	17.92	3.05
T1 - Most Critical Assets	0.09	2.46	0.22	0.09	0.97	0.09
T2 - Next Most Critical Assets	0.14	14.07	1.97	0.14	13.91	1.95
T3 - Highly Important Assets	0.17	5.97	1.01	0.17	5.95	1.01

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[46] Please refer to Seismic RAMP Risk Model (excel file).

[47] Specifically for Seismic Risk, the individual LoRE values for each tranche are not additive. An earthquake that affects one tranche will likely also affect other tranches, since our tranches are by type of building, not

(*Continued*)

1. Overview

The Proposed Plan expands the current pace of seismic retrofit efforts during the 2025-2028 RAMP period (from ~$44M/yr to ~$51M/yr). Due to the large amount of residual seismic "safety"- and "reliability"-related risk (see SCE Seismic Resiliency Pyramid in Figure II-5), most notably the potential for up to a 22-day duration disruption of service from a scientifically plausible catastrophic earthquake (see Figure II-4), SCE plans to request additional funding for the existing SRP. Our Proposed Plan for 2025-2028 will strategically increase the pace, scope and investment in the SRP while also continuing to optimize the efficiency of the program to achieve the greatest benefit with funds made available.

Seismic mitigations being completed by SCE so far include making structural and non-structural improvements within SCE buildings, as well as replacing and strengthening computer equipment and battery racks. The mitigations also encompass bulk substation switchyard mitigations such as replacing equipment components and improving anchoring of large transformers. In general, seismic risk is evaluated through an iterative process of assessment and mitigation. After bringing a facility from "as is" condition (at time 1, say, in 2022) to "remediated" (at time 2, say, in 2027), it is then assessed again to determine the status of other residual risks. If necessary, SCE would then perform additional mitigations.

2. Execution Feasibility

The Proposed Plan is feasible to execute. Currently, the rate of project work is being conducted at approximately four-fifths of the pace proposed for 2025-2028. Within the electric structure workstream, four bulk MEERs and eight distribution MEERs are being retrofitted in 2022. In the IT/Comm workstream, one data center rack mitigation project and eight communications room rack mitigation projects will be completed. In 2022, the generation workstream will complete seismic mitigation improvements on several vulnerable components at three SCE-owned peaker plants.

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geographic location. Each tranche of building appears in different places in our service territory. Thus, it appears that summing could result in double-counting earthquakes. Therefore, the overall seismic LoRE is not a sum, but is the maximum LoRE value of the individual tranche LoRE values. The same is true for the LoRE figures that appear for each of the two Alternative Plans.

All workstreams will continue their ongoing assessment and prioritization efforts. Over the 2023-2024 years, SRP work is expected to continue at the same current or somewhat accelerated pace. Accordingly, SCE anticipates that by 2025-2028 the Proposed Plan can be executed with a high degree of competence and confidence.

3. Affordability

SCE considers the overall value of mitigation work in order to optimize seismic design for customer affordability over the long term. At a high level, SCE considers the trade-offs implicated by the criticality of an asset, its age (and remaining expected life expectancy), and the goal of balancing the achievement of minimization of long-term total costs of owning and maintaining that asset versus perceived short-term customer-affordability concerns.

4. Other Considerations

Another driver in decisions is the potential for the mitigation work to disrupt operations and service. This operational impact and schedule of mitigations need to be balanced. For example, within the data center environment, even the need to perform destructive testing, such as taking concrete core samples, can create dust which represents a serious risk to operational continuity. In a recent example that required serious consideration of this issue, an additional year of preparations would be required for “data clean” and careful movement of equipment so as not to disrupt operations.

VII.
ALTERNATIVE PLANS

A. Alternative Plan #1

SCE developed Alternative Plan #1 as shown in Table VII-6. The pre- and post-LoRE, CoRE and risk scores are summarized by tranche below in Table VII-7.

Table VII-6
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[48]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Seismic Building Safety Program – Electric	$0.2	$51.5	445
C1 - T3	Seismic Building Safety Program – Electric	$0.2	$32.0	13
C2 - T2	Seismic Building Safety Program – IT Telecom		$8.8	272
C3 - T1	Seismic Building Safety Program – Generation		$4.8	1,556
C4 - T1	Facility Emergency Management Program	$0.4		15
C4 - T2	Facility Emergency Management Program	$0.4		28
Total		**$1.2**	**$97.1**	**-**

Table VII-7
Pre- and Post- LoRE, CoRE and Risk Scores[49]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Seismic	0.17	18.86	3.21	0.17	18.26	3.10
T1 - Most Critical Assets	0.09	2.46	0.22	0.09	1.44	0.13
T2 - Next Most Critical Assets	0.14	14.07	1.97	0.14	14.01	1.96
T3 - Highly Important Assets	0.17	5.97	1.02	0.17	5.96	1.01

1. Overview

An alternative to the Proposed Plan would be the following: instead of the proposed increased scope found in the Proposed Plan, SCE could instead keep executing projects at a somewhat

48 Please refer to Seismic RAMP Risk Model (excel file) and WP. Ch. 8 – Seismic RAMP Financials.
49 Please refer to Seismic RAMP Risk Model (excel file).

reduced level relative to current scope (from ~$44M/yr to ~$25M/yr). If we materially reduce the pace of SRP, then safety and reliability risk would not be reduced as expeditiously. Instead of selectively increasing the pace of projects that are primarily driven by reliability considerations, greater acceptance of risks associated with widespread outages would be incurred. In other words, if expenditures are somewhat reduced through 2025-2028, that would mean that important reliability-related seismic work would be deferred until later than 2028.

For example, SCE has already identified residual risks at assets near the top of Tranche 1. Under Alternative Plan #1, that important work for specific structural and non-structural seismic retrofits would potentially be delayed until after 2028. At its core, the question of going with the Proposed Plan versus this somewhat reduced scope (Alternative Plan #1), or the even more reduced-scope found in Alternative Plan #2, is a matter of the level of seismic risk acceptance. In SCE's view, neither of the Alternative Plans represent as prudent a choice to reduce seismic risk when compared to the Proposed Plan.

2. Execution Feasibility

Twenty-seven building seismic retrofits have been completed as of 2022, and many more will be performed from 2022-2024, so by 2025-2028 SCE will be in a strong position to execute additional retrofits as needed. We have an experienced and high-performance team working on this effort. As resources are made available, our team has demonstrated its ability to execute ambitious plans on budget and schedule.

3. Affordability

Cost estimation for seismic retrofits is challenging, but SCE has made recent significant improvements in the methodology employed on optimal seismic retrofit design and retrofit cost estimation procedures, as described in the supporting workpapers.

4. Other Considerations

Please see Section VI.4.

B. Alternative Plan #2

SCE developed Alternative Plan #2 as shown in Table VII-8. The pre- and post-LoRE, CoRE and risk scores are summarized by tranche below in Table VII-9.

Table VII-8
Alternative Plan #2 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[50]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Seismic Building Safety Program – Electric	$0.2	$30.0	498
C1 - T3	Seismic Building Safety Program – Electric	$0.2	$16.0	13
C2 - T2	Seismic Building Safety Program – IT Telecom	-	$8.8	272
C3 - T1	Seismic Building Safety Program – Generation	-	$4.8	1,556
C4 - T1	Facility Emergency Management Program	$0.4		15
C4 - T2	Facility Emergency Management Program	$0.4		28
Total		**$1.2**	**$59.6**	**-**

Table VII-9
Pre- and Post- LoRE, CoRE and Risk Scores[51]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Seismic	0.17	18.86	3.21	0.17	18.38	3.12
T1 - Most Critical Assets	0.09	2.46	0.22	0.09	1.66	0.15
T2 - Next Most Critical Assets	0.14	14.07	1.97	0.14	14.01	1.96
T3 - Highly Important Assets	0.17	5.97	1.01	0.17	5.96	1.01

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[50] Please refer to Seismic RAMP Risk Model (excel file) and WP. Ch. 8 – Seismic RAMP Financials.
[51] Please refer to Seismic RAMP Risk Model (excel file).

1. Overview

As an alternative to retrofitting SCE's assets at either the increased rate (Proposed Plan), or at a somewhat reduced rate (Alternative #1), this Alternative #2 would decrease the pace of the Seismic Resiliency Program significantly below its current rate (from ~$44M/yr to ~$15M/yr).

2. Execution Feasibility

Reducing the pace of the current program is feasible; however, under Alternative Plan #2 we would be reducing safety and reliability risks at a significantly lower level. Reduced scope would fail to expeditiously realize benefits of retrofits in terms of safety, reliability and financial consequences in case a significant earthquake occurs.

3. Affordability

The affordability of a reduced-scope program would favor minimizing short-term costs of seismic retrofits rather than rather than minimizing long-term total cost of ownership of SCE's assets. SCE respectfully believes that would be a short-sighted approach. Any perceived customer affordability benefit derived from a reduced near-term scope of work would simply make future necessary expenditures more expensive for customers, because the inherent seismic risk does not go away, and customers would not benefit from the mitigations set forth in the Proposed Plan.

4. Other Considerations

Please see Section VI.4.

VIII.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

In the 2018 RAMP, stakeholders requested that SCE utilize earthquake magnitude instead of an intensity measure such as peak ground acceleration (PGA). Our RAMP chapter analysis and narrative comply with that request. The workpapers for this chapter appropriately make additional use of more detailed, technical methods.

B. Data Collection and Availability

In one area of risk quantification, SCE recognizes a need for improvements and has identified and received support for a project to assist with the necessary maturation of the SRP. This program is facilitated and supported by the EPIC III program overseen by the CEC. The project started in Q2 of 2022, and will be concluded by Q4 of 2024. It is called the Advanced Comprehensive Hazards Tool (CHaT).[52] It is expected that the CHaT project will deliver a solution that is useful and can be implemented, in which case SCE will begin using it in an operational support role to better guide the development of recommendations to in turn help improve the process for prioritizing mitigation efforts.

C. Performance Metrics

SCE uses the reduction of duration of interruption of service to number of customers -- that is, we prioritize mitigations that can reduce CMI. For this RAMP period, SCE's SRP goal is to reduce the total, projected widespread outage CMI expected from a catastrophic earthquake by 20%, which is an approximation of the portion of the CMI reduction that SCE can control through mitigations, such as seismic retrofit of critical buildings.

For example, the extensive completed seismic mitigation of SCE switchyards has already greatly reduced potential for widespread outage. SCE has begun the remediations for recognized structural deficiencies in substations, but much work remains to be done. The performance metric for tracking progress involves, in part, counting the number of completed MEER retrofits in terms of project management. However, the goal of this overall effort is to continue to improve reliability and seismic resiliency of the system overall. For that overall performance metric, we tie all reliability-based mitigations back to reducing that portion of CMI that SCE can control through mitigation projects at SCE facilities.

52 The scope of this effort is to integrate probabilistic and deterministic modeling with fragilities data across all assets in order to more quantitatively address and link between component-level damage to circuit-level. This should provide a more detailed understanding of anticipated widespread outages from scenario earthquakes.

IX.

ADDRESSING PARTY FEEDBACK

In its review of SCE's 2018 RAMP, the Commission's Safety and Enforcement Division recommended that the Building Safety Risk Chapter be replaced with a new proposed risk – seismic risk to generation, distribution and transmission assets.[53] Taking this feedback into consideration, SCE revisited the Building Safety risk from the 2018 RAMP and decided to focus this risk solely on the seismic risk to our assets. As described above, the seismic risk of potential building collapse is especially important for industrial buildings that house electric facilities (major substations, transmission, sub transmission, and distribution systems), IT/Comms assets, and SCE-owned non-hydro generation assets. Similarly, SCE's SRP includes a new "reliability" element, which involves a strategic pivot as SCE now includes this factor in decisions about prioritizing facilities for retrofit, and about how retrofit design will be considered.

[53] *See* "A Regulatory Review of the Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case," p. 56. This document was placed into the record of I.18-11-006.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Employee Safety

Chapter 9

Rosemead CA
May 13, 2022

Chapter 9: Employee Safety

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Chapter 9: Employee Safety

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I.

EXECUTIVE SUMMARY

A. Risk Overview

SCE's vision is to strengthen its safety culture, eliminate serious injuries and fatalities, and reduce all injuries. The safety of SCE's customers, the general public, SCE employees, and outside contractors[1] is continually of the utmost importance to SCE. Edison Safety is the lead organization that provides guidance, governance, and oversight concerning the Company's safety programs and activities that focus closely on worker safety to accomplish the goal of creating an injury-free workplace.
Our efforts include, but are not limited to, developing and managing programs to meet requirements outlined by governing regulatory agencies, including Occupational Safety and Health Administration (OSHA) and the California Division of Occupational Safety and Health (Cal/OSHA).

Our endeavors also encompass leading all major safety incident evaluations, tracking and analyzing the company's safety data and records, managing and implementing SCE's Safety Culture Transformation, and managing all other employee (field and office) safety programs and standards. Edison Safety also partners closely with SCE operating units (OUs) to help ensure that each OU activity-specific safety program improves safety performance, fosters SCE's safety culture, and meets applicable compliance requirements.

The work that employees perform to maintain the electric system is diverse, and includes activities such as:

- Installing and replacing transmission and distribution utility poles, towers, and electrical overhead conductors and underground cables;
- Managing vegetation around overhead equipment;
- Maintaining electrical assets at over 800 substations;
- Maintaining administrative and operational facilities that support grid operations;
- Transporting tools and equipment to worksites; and

[1] SCE specifically addresses the risks for contractor safety in a separate chapter. Please refer to Chapter 10 - Contractor Safety.

- Performing office work to support all of the above activities.

We perform these potentially hazardous tasks in order to provide safe, reliable, affordable, and clean electricity to our customers across a 50,000-square mile service area.[2] Historically speaking, the majority of incidents that result in serious injuries or fatalities occur in the field, and are experienced by lineman, apprentice lineman, troubleman and groundman job classifications. In this chapter, SCE discusses actions that are taken to protect employees from safety risks that can result in serious injuries or fatalities (SIFs), as defined by the Edison Electric Institute's (EEI) SIF criteria.[3]

SCE identified a number of compliance activities, controls, and new mitigations to address these risks and threats.[4]

- This chapter describes one compliance activity related to various regulatory and legal requirements that necessitate that SCE maintain safety standards, programs, and policies for the welfare of our employees.

This chapter evaluates five controls:

- Safety Culture Transformation (C1): This includes activities to transform our safety culture.
- Incident Cause Evaluation (C2): This includes activities concerning the Corrective Action Program to identify learnings; the goal is to leverage learnings to reduce future safety incidents.

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[2] To better drive public safety efforts through a common risk approach, in December 2021 SCE shifted the public safety function from Edison Safety to our Enterprise Risk Management (ERM) organization. ERM oversees a multi-Operating Unit execution model to create a common risk management framework and modeling capability for public safety, and to provide a single source of public safety risk information to foster risk-informed decision-making across the enterprise.

[3] Please refer to WP Ch. 9, Edison Electric Institute Serious Injury and Fatality Criteria for a further description on what incidents are designated as SIFs.

[4] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter 2 – Risk Model and RSE Methodology, compliance activities are not modeled in this report. Compliance activities are addressed in Section III. C = Control. This is an activity performed prior to or during 2022 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report and are addressed in Section IV. M = Mitigation. This is an activity commencing in 2023 or later to address the risk. Mitigations are modeled in this report and are addressed in Section V.

- T&D Field-Based Training (C3): This includes activities to utilize agile and informal training to assist employee development and learning, in addition to facilitating formal training programs.
- Human and Organizational Performance (C4): This includes a cornerstone program for SCE to continue maturing as a proactive learning organization where all employees, leaders and executives work together to prevent serious injuries and fatalities.
- Safety Predictive Initiative (C5): This includes activities to build on SCE's strategy to use data proactively to spur learning, aid action planning, and drive decision-making to help reduce and eliminate SIFs.

Finally, this chapter evaluates two mitigations:

- Expanded Industrial Ergonomics Program (M1)
- Enterprise-Wide Virtual Driver Safety Training Program (M2)

Pursuant to Mitigation #1 (M1), SCE would transition to a broader comprehensive approach for sprains and strains. Pursuant to Mitigation #2 (M2), SCE would implement a virtual training program for approximately all 12,700 SCE field and office employees.

The Proposed Plan continues existing programs (C1, C2, C3, C4,[5] and C5).

- Alternative Plan #1 implements Expanded Industrial Ergonomics Program (M1).
- Alternative Plan #2 implements Enterprise-Wide Virtual Driver Safety Training Program (M2).

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Employee Safety.[6] As discussed below, SCE is currently evaluating new mitigations to further reduce our Employee Safety risk. This includes expanding Human and Organizational Performance, the Safety

[5] C4 – Human and Organizational Performance does not currently have proposed scope in 2025 – 2028.

[6] LoRE – likelihood of risk event. CoRE – consequence of risk event. Risk Score is the product of the LoRE and CoRE. For additional information on the risk modeling methodology, please refer to Chapter 2 – Risk Model and Methodology.

Predictive Initiative, and risk mitigations (multi-year initiatives with resource requirements) we developed through the Risk-Based Safety Program.[7] We currently anticipate that we will provide an update in our GRC Application in May 2023.

For Employee Safety risk, key mitigations such as training necessarily have a duration of a few years before the training must be retaken to continue its effectiveness, remind the training audience of the crucial concepts, and reinforce key messaging. Therefore, these mitigations have a shorter life than other mitigations such as capital investments whose useful life is measured in decades. So despite the effectiveness of Employee Safety mitigations like training, the shorter lifespans translate to flat risk scores when we compare 2025 to 2028.

Table I-1
Summary of Pre and Post LORE and CORE Risk Scores[8]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Employee Safety	7.80	0.1	1.00	7.80	0.1	1.00

II.

RISK ASSESSMENT

A. Risk Definition and Scope

The Employee Safety risk involves incidents leading to serious injuries or fatalities to SCE employees, related to:

- Hazards arising from construction or maintenance activities
- Hazards arising from supporting activities
- Vehicle incidents

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7 The Risk-Based Safety Program is classified as a foundational activity for RAMP purposes, and is discussed in detail as F1 in the Foundational Activities section below.

8 Refer to Employee Safety RAMP Risk Model (excel file).

To address this risk, SCE constructed a risk bowtie, as shown in Figure II-1. The scope of this risk is further defined below in Table II-2.

Table II-2
Scope of Employee Safety Risk

In Scope	Incidents leading to actual Serious Injuries or Fatalities (SIF) to SCE employees, as defined by EEI SIF criteria.
Out of Scope	Incidents leading to Potential Serious Injuries or Fatalities, as defined by the EEI Safety Classification and Learning Model criteria.
	Lower severity incidents that do not rise to the level of a Serious Injury or Fatality, as defined by EEI SIF criteria.

The number of SCE employees is a key factor in the exposure that this risk presents. In 2021, SCE's employee workforce consisted of approximately 12,700 employees (counting both field employees and office employees). SCE defines field employees as SCE employees who perform more than 50% of their job responsibilities outside of the office environment, including working on or operating SCE's electrical system. SCE defines office employees as SCE employees who perform more than 50% of their job responsibilities inside an office environment. A further discussion on how SCE divided the exposure into tranches is discussed in Section II.F.

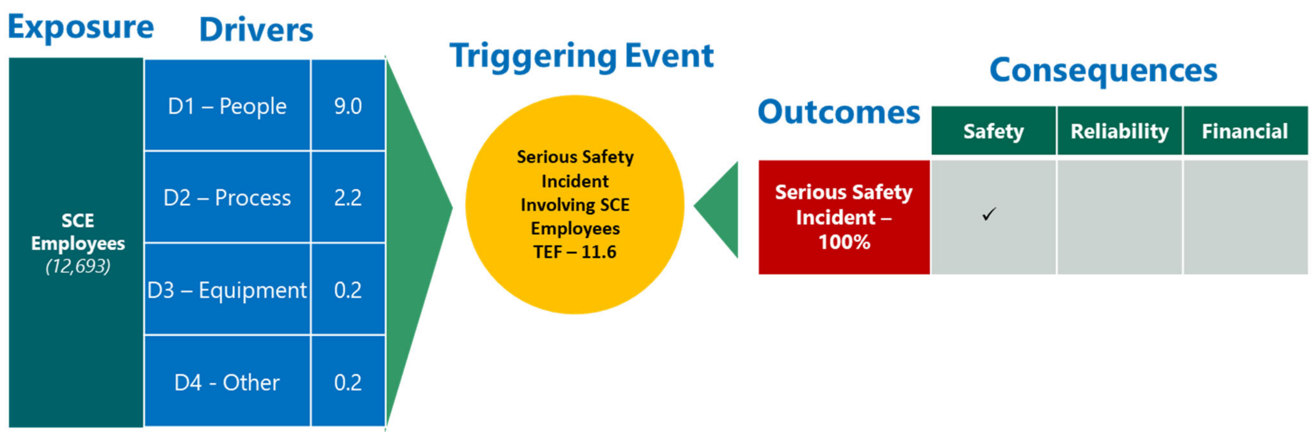
B. <u>Risk Bowtie</u>

In the 2018 RAMP, SCE included a chapter that had employee, contractor and public safety in one bowtie.[9] For the 2022 RAMP, SCE has made several updates to provide more visibility to employee safety. First, SCE constructed an employee-only safety risk bowtie as shown in Figure II-1 to clearly differentiate the employee risk from contractor and public safety risks. Second, the 2022 RAMP bowtie

[9] *See* SCE 2018 RAMP Report Chapter 7 – Employee, Contractor and Public Safety.

focuses specifically on serious safety incidents, which are defined as incidents resulting in serious injury or fatality, according to the EEI SIF criteria.[10]

Figure II-1
Risk Bowtie for Employee Safety[11], [12]



In 2018, SCE began tracking serious injuries according to EEI criteria (and retroactively classified data from prior years). In 2020, SCE began implementing the EEI Safety Classification and Learning (SCL) model. The primary purpose of this model is to address the common industry challenge of serious injury and fatality prevention. The model provides a scientific basis for identifying incidents that *could have* resulted in serious injury or fatality, which expands individual utilities' and the industry's ability to learn and take preventive action.

[10] Please refer to WP Ch.9, Edison Electric Institute Serious Injury and Fatality Criteria for a further description on what incidents are designated as SIFs. For purposes of this RAMP analysis, a SIF would include incidents categorized as: (1) High-Energy Serious Injury or Fatality (HSIF) - Incident with a release of high energy in the absence of a direct control where a serious injury is sustained; and (2) Low-Energy Serious Injury or Fatality (LSIF) - Incident with a release of low energy in the absence of a direct control where a serious injury is sustained.

[11] Some of these events may have a potential financial consequence – namely, the potential costs of workers compensation claims and/or third-party lawsuits arising from the outcome(s) that the programs and activities are designed to minimize and/or prevent. SCE has not included those potential consequences in this RAMP, however, consistent with its past practice and in order to appropriately maintain confidentiality and protect attorney-client privileged information.

[12] Please refer to WP. Ch. 9 - Baseline and Risk Inputs.

The SCL model uses the energy-assessment method, which is built on evidence that serious injuries are the result of some undesirable contact with energy of a certain magnitude (e.g., electrical voltage, speed in a vehicle, or falling from elevation). The model also identifies whether direct controls were in place to protect the employee from contact with the energy source. Its categorizations enable learning from actual serious injuries and fatalities and from potentially serious incidents. Please refer to Section IX.A.2 for a discussion on Potential Serious Injury or Fatality (PSIF) incidents.

SCE believes that aligning with EEI criteria is beneficial for several reasons. Utilizing benchmarking data with utilities outside of California provides a greater degree of insight and experience. SCE will also leverage the work of EEI's working group(s) of industry safety leaders and technical advisors and experts. This approach allows SCE to learn from potential incidents as well as the incidents that result in serious injuries/fatalities. It also provides a more comprehensive picture when SCE is communicating learnings to the Commission. In addition, SCE will be able to leverage industrywide data that will be more statistically significant and will provide better insights for future safety mitigation efforts. To give an example, SCE has not experienced an employee fatality in the last five years; but when one combines the data from the rest of the industry, that number will increase. This will assist SCE in taking valuable lessons learned from other utilities and applying such lessons proactively to SCE's operations and procedures.

C. <u>Drivers</u>

SCE has identified four primary drivers per 2017-2021 Internal SCE Data for SIFs according to the EEI serious injury and fatality criteria; 78% of primary drivers related to "People" and 19% related to "Process." These drivers and their annual frequencies are shown below in Table II-3.

Table II-3
Historical Driver Information

RAMP Drivers	Total (2017 - 2021)	Annualized Frequency	% of Driver Frequency
D1: People	45	9.00	**78%**
D2: Process	11	2.20	**19%**
D3: Equipment	1	0.20	**2%**
D4: Other: Beyond the Control of SCE	1	0.20	**2%**
Totals	**58**	**11.6**	**100%**

1. D1 – People

The People driver category includes incidents that were caused by human factors, including intentional shortcuts and unintentional human errors or conditions. The sub-drivers are defined as:

- Lack of Hazard Awareness: A failure to identify, correct, and/or account for hazardous conditions in the work environment or work practices;
- Work Practice: Poor or inadequate workplace practices or methods that expose employees to additional risks;
- Physical Capabilities: Indicates the body's lack of ability to withstand the work due to different situations, which include industrial ergo, pre-existing conditions, lack of understanding of physical limitations, fatigue, and fitness for duty;
- Adherence to Rules, Training or Policy: Employee knowingly or unknowingly violates a procedure, policy or rule, leading to incorrect execution of work; and
- Tool/Equipment/Operation: An employee's choice of tool/equipment or their operation of a tool/equipment creates increased risk.

Table II-4 below summarizes the sub-drivers associated with People.

Table II-4
People RAMP Sub-drivers

People RAMP Sub-drivers	Total (2017 - 2021)	Annualized Frequency	% of People Driver Frequency
Lack of Hazard Awareness	25	5	**56%**
Work Practice	10	2	**22%**
Physical Capabilities	5	1	**11%**
Adherence to Rules, Training or Policy	3	1	**7%**
Tool/Equipment/Operation	2	0	**4%**
Totals	**45**	**9**	**100%**

2. D2 – Process

In the Process driver category, a standard or process either does not exist to address safety hazards, or the current standard/process is inadequate and needs improvement. The sub-drivers are defined as:

- Lack of Formal Process/Poor Process: Inadequate or missing process or procedure;
- Tool/Equipment/Operation: Tool, equipment or operation failed and caused an incident due to lack of maintenance or inspection;
- Working Conditions: Surrounding conditions adversely affected the safety of the employee. Conditions include unexpected or abnormal conditions, working alone, performing work during hours of darkness, and real or perceived time pressure or urgency; and
- Lack of/Poor Communication: Communication (e.g., formal communication, tailboards) is inadequate to foster safety.

Table II-5 below summarizes the sub-drivers associated with People.

Table II-5
Process RAMP Sub-drivers

Process RAMP Sub-drivers	Total (2017 - 2021)	Annualized Frequency	% of Process Driver Frequency
Lack of Formal Process/Poor Process	6	1.20	**55%**
Tool/Equipment/Operation	2	0.40	**18%**
Working Conditions	2	0.40	**18%**
Lack of/Poor Communication	1	0.20	**9%**
Totals	**11**	**2.2**	**100%**

3. <u>D3 – Equipment</u>

The Equipment driver category is defined as a failure in equipment design that leads to an incident, or equipment design that creates an error trap for individuals and leads to an incident. Examples include a vehicle engine manufacturer design failure that causes a fire, a pinch point created due to equipment or system design, or error traps such as distraction or confusing displays or controls.

4. <u>D4 – Other</u>

The Other driver category includes incidents beyond SCE's control, such as a vehicle incident caused by a member of the public.

D. <u>Triggering Event</u>

The triggering event is defined as a serious safety incident involving employees, resulting in serious injury or fatality, according to EEI SIF criteria. The triggering event frequency is composed of the estimated annual frequencies of D1–D4.

E. <u>Outcomes and Consequences</u>

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%. For purposes of risk modeling, the only consequence SCE has identified for this triggering event is a safety consequence. The other two consequences, financial and reliability, are not directly applicable to this specific safety-focused triggering event.

F. Tranches

SCE looked at several factors when determining the tranches for the Employee Safety risk, including but not limited to, job field/class, location, operating unit, and SIF exposure categories. Ultimately, SCE decided to use job field/class to create the tranches. Having tranches at the job class level is consistent with how SCE focuses on developing mitigations and controls specifically to appropriately reduce the risk in those areas.

Based on the level of risk associated with the work performed by employees, SCE has assigned three tranches. First, similar to the approach taken by PG&E in its most recent RAMP filing, SCE differentiated between office and field employees.[13] SCE believes this is a prudent approach. An office employee has a different risk profile than an employee out in the field. Moreover, many of our controls and mitigations focus on SCE's field workforce. SCE, in alignment with SPD's and other parties' comments on utility RAMP showings,[14] agrees that the tranche of field employees can be further broken down into additional and more specific tranches. Thus, SCE further tranched the field employees tranche into two sub-tranches: 1) Lineman/Journeyman, Apprentice, Troubleman and Groundman; and 2) all other field employees.

Table II-6 below shows the historical triggering event frequency by Tranche as well as the exposure, measured in number of employees.

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[13] SCE further discusses our tranching approach in Section IX.A.1.

[14] *See*, *e.g.*, 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, p. 72.

Table II-6
Historical Triggering Event Frequency by Tranche

Tranche ID	Tranche Description	Exposure (# of Employees)	Percent of Risk Exposure	LoRE / TEF	% of TEF
T1	Office Employees	8,894	70%	1.4	12%
T2	Field - Lineman/Journeyman, Apprentice, Troubleman and Groundman	1,446	11%	6.4	55%
T3	Field - All other field workers	2,353	19%	3.8	33%
Total		**12,693**	**100%**	**11.6**	**100%**

G. <u>Related Factors</u>

For purposes of this discussion, SCE defines related factors as factors that are not directly included in the risk modeling but can impact the driver frequency and/or the likelihood of certain outcomes. The identified factors for the Employee Safety chapter of RAMP risk are summarized below in Table II-7. Based on current data collecting abilities, we are not able to quantitively show how they impact the risk bowtie components.

Table II-7
Related Factors Impacting Employee Safety

Related Factors	Description
Climate Change	The Climate Adaptation and Vulnerability Assessment (CAVA) examines vulnerabilities to operations and services that could result in findings related to employee safety, including increased drivers of employee safety risk events and potential solutions to reduce the likelihood or consequences for employee safety risk events. For further details regarding the CAVA, please refer to Appendix B – Climate Change.
Physical Security	As discussed in Chapter 11, potential exists for a major physical security incident that could result in workplace violence. The potential consequences associated with those events are included in the Physical Security chapter.
Talent Attraction and Retention	The potential inability to attract or retain qualified applicants to certain open positions could potentially result in impacts to core business productivity and success, and negatively impact employee safety.

III.

COMPLIANCE

SCE describes one compliance activity below. As described in Chapter 2 – Risk Model and RSE Methodology, SCE is not modeling the compliance-based work. In SCE's 2018 RAMP we included a compliance activity titled CM2 – Safety Compliance – Technical Training.[15] Upon further evaluation of this work for the 2022 RAMP, SCE elected to include this as a control (C3 – T&D Field Based Training). SCE is still required to perform these activities according to Title 8 of the California Code of Regulations and Title 29 of the Code of Federal Regulations, as well as function-specific regulations according to Department of Transportation and Federal Aviation Administration, as indicated in our 2018 RAMP. However, the rules do not always specify how the training should be delivered, what the duration and/or frequency of the trainings should be, and/or the content that is required to be included in

[15] *See* SCE 2018 RAMP Report Chapter 7 – Employee, Contractor and Public Safety.

the trainings. Therefore, on balance SCE decided to include pertinent aspects of our field employee training as a control in this RAMP.

A. CM1 – Safety Compliance – Standards, Programs & Policies

Title 8 of the California Code of Regulations requires that employers maintain safety standards, programs, and policies for the welfare of their employees. Accordingly, SCE maintains a number of safety standards, programs and policies, some of which are listed below:[16]

- Bloodborne Pathogens Exposure Control Standard;
- Hazard Communication and Chemical Management Standard;
- Confined Space Program;
- Fall Protection Standard;
- Hazardous Energy Control (LOTO) Standard;
- Hearing Conservation Program;
- Heat Illness Prevention Program;
- Hot Work Program;[17]
- Injury and Illness Prevention Standard;
- Respiratory Protection Program; and
- Safety Incident Management Standard.

These requirements and processes are designed to mitigate risk to employees when followed. SCE routinely reviews its standards, programs and policies to help ensure they are accurate, effective and up-to-date.

IV.

CONTROLS

In addition to safety compliance work discussed above, SCE has identified four controls that are included in the risk analysis. These are shown in Table IV-8.

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[16] Please refer to WP Ch. 9, Safety Standards, Programs, and Policies.

[17] Hot work activities include soldering, welding, pipe-cutting, heat-treating, grinding, thawing pipes, hot riveting, torch-applied roofing and any other application involving heat, sparks or flames.

Table IV-8
Inventory of Employee Safety Controls[18]

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
C1	Safety Culture Transformation	D1, D2	-	-	Yes	All
C2	Incident Cause Evaluations	D1, D2, D3	-	-	No	All
C3	T&D Field Based Training	D1, D2, D3	-	-	No	All
C4	Human and Organizational Performance	D1, D2, D3	-	-	No	All
C5	Safety Predictive Initiative	D1, D2	-	-	No	All

A. C1 – Safety Culture Transformation

SCE is committed to delivering safe, reliable, affordable and clean energy. One of the core tenants is ensuring that our employees are equipped with the perspectives and tools to protect themselves for who and what they value. The programs and projects outlined in this chapter exist to keep people safe, but the specific programs and projects need to be supported by the strong foundation of a safety-focused culture.

For the last several years, SCE has been on a productive journey of developing and fostering a stronger safety culture. We believe we have made meaningful progress in improving safety culture and performance. SCE's progression through our Safety Culture Maturity Model, as shown below in Figure IV-2, is currently focused on evolving from Public Compliance, where employees follow rules primarily because of potential consequences, to Private Compliance, where employees are motivated to make safe choices to protect themselves for who and what they value. In practical terms, a Private Compliance perspective is one where employees make the safest choice through intrinsic motivation and care, rather than making that choice because "someone is looking."

A Private Compliance mindset sets the foundation for employees' discretionary efforts to use SCE's safety programs, processes, and tools to systematically identify and mitigate risk. SCE's

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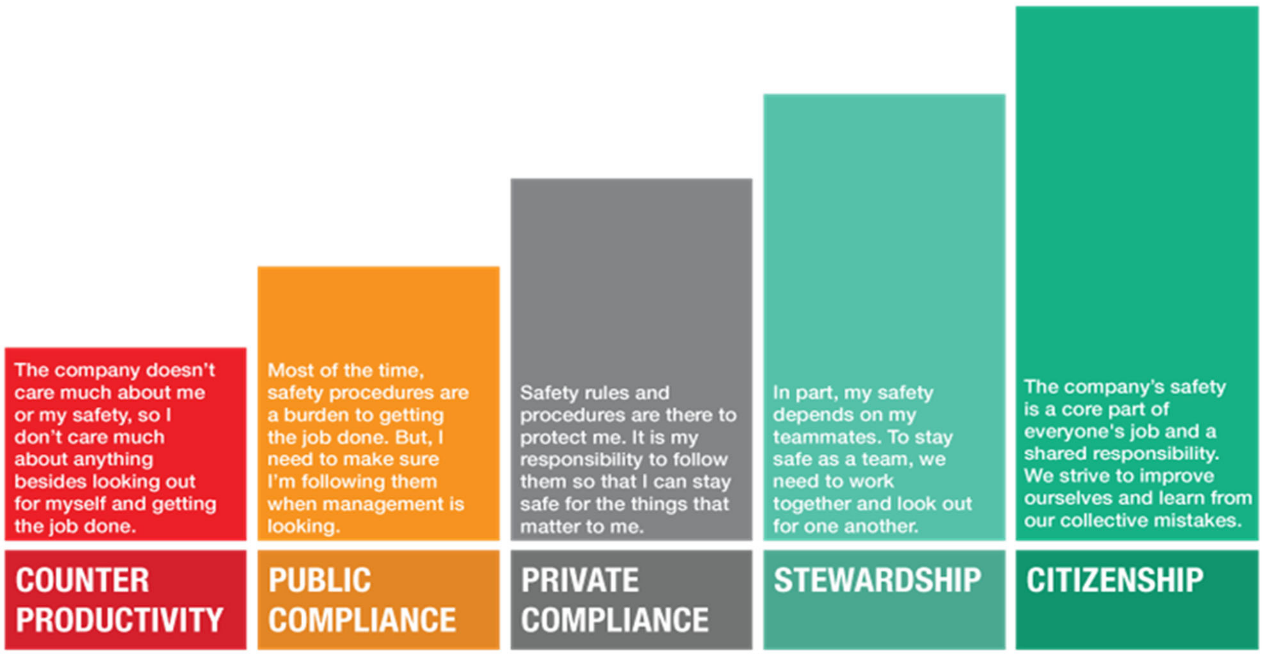
[18] Please refer to WP. Ch. 9 – Baseline and Risk Inputs.

employee safety programs drive improvements in how we perform the work, and how we identify and mitigate safety risks at all times. Safety ownership through Private Compliance fosters acceptance and adoption. This integrated approach holistically addresses safety risks to our employees and the public.

Figure IV-2
Safety Culture Maturity Model



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1. <u>Safety Culture Efforts</u>

As the result of a comprehensive enterprise safety culture assessment conducted in 2014, SCE leaders representing every operating unit came together to develop SCE's initial Enterprise Safety Roadmap. The purpose of this roadmap was to chart SCE's journey to becoming an injury-free organization. An enterprise safety governance structure was created to align the company on our safety direction and execute Enterprise Safety Roadmap initiatives. This includes the Executive Safety Council (consisting of the CEO and his direct reports), and the Senior Safety Council (consisting of executive representatives from all operating units).

The 2014 assessment and resulting roadmap focused on 27 initiatives in 2015 through 2016. These initiatives were targeted at key areas identified in the assessment as safety culture gaps. The initiatives included improving the safety governance structure, building core leadership safety competencies, developing and implementing safety observation and recognition programs, and refining measurement and analytics processes. In 2017, SCE formalized safety as the number-one core company value, and created a chief safety officer position that reported directly to the CEO. This highlighted our long-term commitment to improving safety culture. In 2017, we engaged the safety consulting firm Propulo[19] to assess our safety culture, and help us update and implement our roadmap to drive continued improvement.

Based on the assessment, SCE implemented an updated safety culture roadmap. As part of this roadmap, all leaders and employees were provided consistent safety culture language, concepts and tools through cognitive behavioral training between 2018 and 2020. Our safety culture was reassessed in 2020 as part of a standing triennial review. Results indicated significant progress was made in improving our safety culture between the 2017 and 2020 assessments, with 78% of 2020 survey respondents indicating our safety culture has improved, and 75% of respondents indicating they have seen improvement in safety leadership.

The results also identified the next series of mitigation initiatives, which include the following: Leader Safety Ownership and Engagement, Employee Engagement Safety Ownership & Participation, and Safety Culture Measurement and Safety Culture Training Sustainment. SCE will continue implementing Safety Culture Transformation from 2022-2025, with a planned safety culture assessment in 2023 to measure progress and inform adjustments. We anticipate these initiatives will continue to drive wider risk reduction benefits throughout the RAMP period. These are shown in Table IV-9 below.

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[19] Propulo Consulting is a global safety consulting firm that partners with clients across high-hazard industries to deliver sustainable improvement in organizational safety performance. More information about Propulo can be found at https://www.propulo.com/.

Table IV-9
Safety Culture Focus Areas and Initiatives

Safety Culture Focus Areas	Initiatives
Leader Safety Ownership & Accountability	• Safety Commitment and Planning Workshops spanning executive to front line leaders to prioritize safety culture assessment themes and build contextualized OU-specific plans to address triennial assessment findings • Cognitive-behavioral leader safety ownership playbook to build on tools and concepts provided in Safety Culture Training • Leader field engagement to reinforce safety mindset and behaviors • Paired safety observation program for frontline leaders to develop coaching and recognition skillset to improve risk identification and mitigation • Coaching for front line leaders to further embed skillset and tools to sustain a psychologically safety work environment where workers speak up
Safety Culture Measurement	• Quarterly safety culture pulse facilitating increased measurement of leader safety engagement and ownership • Triennial Safety Culture Assessment that measures progress along our safety culture maturity model • Measure impact of safety culture on safety metrics
Employee Engagement Safety Ownership & Participation	• Enterprise-wide program to submit grassroots safety projects that drive continuous safety improvements • Conduct safety Kaizens with front line employees to develop and implement mitigations for high hazard risks • Conduct safety recognition event facilitated by SCE's CEO for employees who demonstrated significant safety engagement and ownership
Safety Culture Training Sustainment	• Safety culture micro-learnings to provide leaders with ongoing refreshers of core safety leader skills and tools to sustain a strong safety culture • Cognitive behavioral leader safety ownership playbook to take specific actions using tools provided in safety culture training • Safety culture micro-learnings to reinforce safety culture concepts and tools to sustain worker safety attitudes and behaviors

2. Drivers Impacted

Safety Culture Transformation will impact the People and Process drivers. SCE’s safety programs drive safe work practices, risk identification, and risk mitigation through formalized processes, tools and work methods. Safety culture initiatives drive intrinsic motivation through shifting safety mindset to one of personal safety ownership, ultimately resulting in behavioral shifts (namely, acceptance and adoption of safety tools and safe work methods/processes). This integrated approach of programmatic and cultural efforts gives our employees ready access to the processes, methods and tools needed for working and acting safely, as well as modern cognitive and behavioral concepts/tools to ensure consistent application.

3. Outcomes and Consequences Impacted

For purposes of RAMP risk modeling, SCE assumed that Safety Culture Transformation does not directly impact the safety consequences of the outcome. However, SCE believes that some aspects of this mitigation (e.g., emphasizing Personal Protective Equipment (PPE) rather than leveraging the hierarchy of controls) may indirectly influence the safety consequence outcome by reducing the severity of an incident.

B. C2 – Incident Cause Evaluations

SCE has established a Corrective Action Program to identify learnings, with the goal of reducing safety incidents. To do this, we have established a cause evaluation process that carefully focuses on identifying organizational and programmatic causes. This is done by partnering with key stakeholders within organizations where a safety incident has occurred. SCE takes a graded approach to conducting cause evaluations by adjusting the level of analysis to align with the severity of the safety incident.
A systematic process is then used to identify the causes, so that effective corrective actions can be put in place with reasonable promptness, in order to reduce the likelihood of these safety incidents re-occurring.

SCE uses a Safety Incident Management System (EHSync) to capture reports of safety incidents such as injuries, illnesses, and close calls. Once incidents are reported, they are screened and classified using the EEI SCL model. This model grades severity based on level of energy that is present, whether controls to mitigate employees' exposure to energy were present and/or effective, and the proximity of employees to energy or the severity of injury/illness sustained.

A cause evaluation type is then assigned that is commensurate with the severity of the safety incident. Root Cause Evaluations are conducted for fatalities. Apparent Cause Evaluations are conducted for serious injuries that involve high energy and close calls that potentially could have resulted in a serious injury. Standard Cause Evaluations are conducted for serious injuries where no high energy was present, and for some injuries that result in days away or restricted duty for the injured employee. There is also an option to identify and capture direct causes and corrective actions for minor injuries and close calls through existing evaluation processes within organizations.

Cause evaluations are performed in partnership with trained cause evaluators and leadership within the organization where the injury or close call occurred. For each evaluation type, a systematic process is used to identify causes and actions to improve performance and mitigate future risks. A review process through a committee or individual stakeholder is required to ensure the quality and effectiveness of the evaluation. Actions resulting from cause evaluations are tracked through completion.

1. Drivers Impacted

Incident Cause Evaluations can impact all three drivers. Multiple analysis techniques are used to identify human performance issues, organizational and programmatic issues, and equipment failures. This is achieved through conducting root cause analyses on incidents to learn various causes and incident types or trends. The learnings from these incidents are shared with various organization unit employees to prevent the same type of incidents occurring again in the future.

2. Outcomes and Consequences Impacted

Incident Cause Evaluations do not directly impact the outcome or safety consequences.

C. C3 – T&D Field-Based Training

SCE utilizes agile and informal training to assist employee development learning, in addition to facilitating formal training programs. This is particularly the case in parts of Transmission and Distribution (T&D) that have a variety of required technical skillsets, numerous hazards related to working with and around electricity, ongoing changes to complex tools and equipment, and advancements that we must keep pace with as the grid incorporates new technologies and operating practices. Having well-trained employees helps keep employees and the public safe and fosters the reliability of the system.[20]

T&D employees plan, engineer, construct, operate, repair, and maintain the T&D facilities and equipment used to deliver electricity to SCE's customers throughout its 50,000-square-mile service area. In order to facilitate the work, T&D Training develops, implements, and evaluates training programs for T&D employees. The technical training programs prepare employees to perform their jobs safely, comply with regulatory requirements and laws, maintain system reliability, and meet the demands of new technology.

The field-based training program is divided into two main categories: (1) developing and delivering training, and (2) Seat-Time training. T&D Training has a staff of full-time instructors; adjunct instructors from SCE's field organizations supplement this staff. This allows the training organization to control fixed costs by absorbing additional students while minimizing permanent staff. The use of field employees to deliver training has the added benefit of immersing the employee in the proper work practices, which they can then share with their co-workers when they return to their field location. T&D Seat-Time training focuses on the time employees spend in training classes, as well as their corresponding travel time to and from training classes.

T&D training programs utilize four main practices:

1. Using a formal structured approach to provide training;
2. Leveraging multiple training methods, such as Computer Based Training (CBT);
3. Incorporating assessments of employee performance; and
4. Implementing programs to promote continuous learning over an employee's career.

Training for many work activities in T&D is uniquely technical, with a focus on the skills needed to understand and use complex, industry-specific tools and equipment and in many cases, perform the work in a potentially hazardous environment. As a result, SCE continues to utilize a structured and formal approach to train T&D employees.

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[20] While SCE did not include reliability consequences in the risk bowtie, proper employee training logically helps minimize outages related to human error.

To deliver effective and comprehensive training to T&D employees, T&D training programs follow a Systematic Approach to Training (SAT). This approach is used to identify training needs, design and develop corresponding training programs, implement the programs, and then evaluate programs to confirm the effectiveness of the training. The SAT follows a five-step process called ADDIE (Analyze, Design, Develop, Implement and Evaluate). This is a standard methodology used throughout the training profession. For example, the programs incorporate effective components such as assessing the employee's knowledge and skills at each progressive step in the training process, developing skillsets and experience through on-the-job training, and tailoring program structure and duration to reinforce key concepts and maximize employees' understanding and information retention.

1. **Drivers Impacted**

T&D Field-Based Training can impact D1 - People, D2 - Process and D3 - Equipment drivers. T&D Training focuses on ensuring proper physical capabilities and enabling safe work practices to perform various field work processes. This is accomplished by delivering a wide array of training focused on specific on-the-job activities such as pole climbing, hot sticking, rubber gloving, grid operations, rescue scenarios, electrician, operator and test apparatus training. We also deliver training on numerous other topics covered through both new-hire training, and the various Apprenticeship programs within the organizations.

Training is supplemented by verifying knowledge retention through on-the-job (OTJ) training logs, supervisor validation, physical assessments, and knowledge assessments to make sure that field employees are both physically capable and possess the knowledge required to complete work safely. In addition, T&D Training provides access to a large volume of job aids and training materials focused on the latest system and equipment design, communications related to system operating bulletins, and other materials related to proper utilization of hardware in the field.

2. **Outcomes and Consequences Impacted**

T&D Field-Based Training does not directly impact the outcome or safety consequences.

D. C4 - Human and Organizational Performance (HOP)

This is a cornerstone program for SCE to continue to advance in maturing as a proactive learning organization where all employees, leaders and executives work together to prevent serious injuries and fatalities. It sets HOP organizational learning-centric guiding principles which have been adopted by high-risk and high-reliability organizations for all levels of the organization to apply them consistently (i.e., people make mistakes, blame fixes nothing, context drives behavior, learning and improving is vital, and leader's response matters). It also provides ground-level practical tools and practices for applying and sustaining the principles to reduce the consequences of normal human errors and strengthen organizational capabilities to "fail safely."

Example of these practical tools and practices include the following:

- Event Learning Form and Process so the organization can proactively learn from the context of incidents and good catches, and address latent organizational deficiencies/traps;
- SCE's Standardized Error Reduction Tools and Practices Reference Guide explaining the what, why, when and how for consistency;
- Monthly thought-provoking sustainability topics to engage leaders and craft employees in ongoing dialogue around the HOP principles and their application in the day-to-day jobs of leaders and craft employees o continue to build and strengthen a learning organization; and
- Other sustainability workstreams to be launched in subsequent years based on HOP maturity.

HOP will build SCE's capability and resiliency through an integrated approach of ongoing education and sustainability across all levels of the organization. HOP recognizes unintentional error as part of the human condition. Adopting this way of thinking will allow SCE to build more appropriately error-tolerant systems by proactively building defenses and addressing organizational latent conditions to reduce the consequences of normal human error and fail safely. With consistent application over time by leaders and individual constructors, and proper allocation of resources for sustainability, this effort will prevent injuries, system interruptions, and equipment damage.

HOP has been adopted as an industry best practice by the North America Transmission Forum (HOP roadmap and principles of operating excellence), National Safety Council, our peer utilities, and many high-risk organizations such as the U.S. Department of Energy and Alcoa. SCE used best practices, focusing on an inclusive and grassroots approach, to strategize the design, development, implementation, and sustainability of HOP.

Currently SCE is focusing this effort on our Substation Construction & Maintenance (SC&M) organizational group. This work effort includes:

1. Completing HOP Training for SC&M in 2022 (Leaders and Individual Contributors).
2. Launching subsequent HOP sustainability efforts beyond 2022 and collaborating with key stakeholders including the training organizations and SC&M leadership.

SCE is also in the process of developing our long-term strategy for implementing HOP across other areas of our organization to ensure organizational readiness and alignment. As a result, we currently do not have a finalized cost estimate for years 2023-2028. Further expansion may require additional organizational readiness and resource requirements for implementation and sustainability. SCE will endeavor to provide updates on this program next year, when we file our Test Year 2025 GRC Application.

1. <u>Drivers Impacted</u>

HOP will impact D1 – People, D2 – Process and D3 – Equipment drivers, as well as organizational drivers contributing to safety risks. By applying the HOP Principles, individual contributors and leaders will be able to proactively identify risk drivers and address them in a learning work environment. Further, identifying and addressing risk drivers based on human/process, engineering, and system/organization on an ongoing basis on the job will be critical to reduce the consequences of normal human error and build the organization's resiliency. For example, risk drivers for Sub Arc Flash include deficiencies in the labeling and signage for the substation equipment. It is critical that leadership provide the resources needed to update and apply substation signage and labeling standards in substations to proactively address this driver.

2. <u>Outcomes and Consequences Impacted</u>

While some aspects of this control as described below may influence outcomes, we did not model these potential benefits, as such indirect impacts are likely not material to this program's primary benefits. SCE does believe that HOP can impact the safety consequence outcome by having leaders and individual contributors proactively identify and address organizational deficiencies to minimize consequences of normal human error. That way, if we fail, we fail safely.

By applying the HOP Principles and Practices as a way of operating at the leader and individual contributor levels, SCE will be able to proactively identify risk mitigations (controls, defenses) to build our organization's capacity to a more fail-safe condition. An example occurs in mitigating the risk for Sub Arc Flash by installing bus differentials.[21] This engineering-based risk mitigation of installing bus differentials on selected buses with greater than 8 calorie/cm^2 incident energy will help reduce the incident energy on bus faults. When there is an electric flash, this mitigation will minimize the consequences of normal human error.

E. C5 – Safety Predictive Initiative

The Safety Predictive Initiative builds on SCE's strategy to use data proactively to learn, aid action planning, and drive decision-making to help reduce and eliminate SIFs. The initiative has two components: (1) Safety Predictive Model (SPM), and (2) Digital Crew Board (DCB).

The SPM, developed in 2018, applied artificial intelligence (AI) and machine learning to process and analyze tendencies of historical data for field employee SIFs and planned work order characteristics. An AI code was developed that flags new Distribution, Construction & Maintenance planned work orders with higher-than-normal risks that may potentially result in a SIF. The code also identifies the top factors that contribute to that high-risk flag. This information is directly populated in the work scheduling and planning system used by field personnel on a daily basis. The SPM, combined with the expertise of the personnel, provide data-driven insights to assist targeted communication and bring greater focus to planning the execution of work in a manner that mitigates risks. This will enhance our

[21] A "bus" in this context is defined as the vertical line at which several components of the power system (such as generators, loads, and feeders) are connected. Bus Differentials represent a sensible method for protecting a substation bus where the arrangement of overhead bus bar and associated switching equipment is installed at transmission and distribution substations and switchyards. Overcurrent protection may be used for bus protection at lower voltage.

employees' ability to identify safety issues even before going out to the field to specifically plan the work.

The SPM has been implemented in eighteen Distribution Districts from 2019 through 2021. The SPM is applied to planned work orders assigned to SCE crews. In 2022 – 2023, we will first focus on enhancing the model to include more work characteristics, crew variables, and more detailed insights. We will then roll out SPM to the rest of the Distribution Districts. In the next five years (2024-2028), we plan to expand the use of the model to emergent work as well as planned work. We are also exploring implementation in Transmission when the Work Scheduling Tool has been fully implemented there.

The DCB, developed in 2019, combined the existing manual crew assignment and team member shuffling process with the insights from the SPM. It is a digital platform which can be accessed directly from touch-screen monitors installed in District offices or on a web browser from a laptop or mobile devices. The DCB alerts field personnel to elevated risks that are present with a particular job. It helps the field supervisor mitigate risk and prevent SIFs by managing the different variables he or she must consider when assigning crews to work orders.

The DCB has been implemented in four Distribution Districts in 2020-2021. We plan to implement it in 17 additional districts in 2022-2023. Taking into consideration and aligning with our technology roadmap portfolio, we will assess the requirements and benefits to implement it for the rest of the Distribution Districts and for Transmission in the next five years (2024-2028).

1. <u>Drivers Impacted</u>

The Safety Predictive Initiative will impact D1 - People and D2 - Process RAMP drivers. The SPM high-risk flag prompts the district supervision to pause and reassess their work planning to ensure appropriate mitigations are in place to address the high-risk factors. The high-risk flag and insights are included in their work planning communication; safety risk discussion is now part of the agenda of their formalized work planning meetings. Digitizing the crew assignment and shuffling process through the DCB gives field supervision real-time prompts of the safety hazards. This in turn helps them nimbly adjust their work assignment and crew shuffling process. It also gives them input on the work orders that may need more focused supervision during execution. The SPM and DCB enhance our capability to identify safety issues even before the field personnel go out to the field to handle a job.

2. Outcomes and Consequences Impacted

The Safety Predictive Initiative does not directly impact the outcome or safety consequences.

V.

MITIGATIONS

In addition to compliance and control activities mentioned above, SCE has identified potential new and innovative ways to mitigate this risk – to further reduce the frequency and/or impact of the risk event. These activities are summarized in Table V-10, and discussed in more detail below.

Table V-10
Inventory of Employee Safety Mitigations

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed and/or Alternative Plans?
M1	Expanded Industrial Ergonomics Program	D1, D2	-	-	No	Alternative Plan #1
M2	Enterprise Wide Virtual Driver Safety Training Program	D1, D2	-	-	No	Alternative Plan #2

A. M1 – Expanded Industrial Ergonomics Program

Historically, SCE's industrial ergonomics efforts have emphasized injury prevention exercises as a primary hazard control and relied on dedicated field safety specialists to provide informal periodic ergonomic guidance and employee coaching. As part of this mitigation, SCE would transition to a broader comprehensive approach for sprains and strains. Key aspects of this industrial ergonomics program include:

- Physical Demands Analysis Evaluation: a process for examining postures, body movements, force, and duration.

- Wearable Technology: utilizing technology-embedded clothing that gives feedback, through computer-based systems, on muscle engagement and potential for overexertion injuries when performing certain work tasks.
- Wellness and Body Mechanics Education: provide education to help employees understand how to take care of their health in crucial areas such as stress management, nutrition, and industrial ergonomic training.
- Onsite Sprains and Strains Early Interventions: Athletic Trainers available in-person to assist employees in first aid treatment of signs and symptoms associated with sprains and strains; this may encompass manual trigger point massage for muscles, and therapeutic exercise recommendations from existing internal programs.
- Return to Work Support: provide employees assessments to evaluate opportunities to support employees safely returning to work when they have missed job time due to work-related and non-work-related circumstances.

1. Drivers Impacted

The adoption of this comprehensive industrial ergonomics program will help improve issues related to D1 - People and D2 - Process RAMP drivers. For example, Industrial Ergonomics interventions provide trainings and job task evaluations to improve hazard recognition and mitigation of work practices that lead to musculoskeletal-type injuries. In addition, interventions will help provide knowledge regarding how to properly use equipment and tools to reduce stress to the body and minimize fatigue of employees, so that physical capabilities can remain at a level to properly and safely meet the demands of the work. Lastly, industrial ergonomic evaluations of work methods help identify inefficient or incorrectly-aligned work processes that expose employees to ergonomic hazards and create unnecessary and unproductive steps when attempting to perform the work in a safe and timely manner.

2. Outcomes and Consequences Impacted

This program does not directly impact the outcome or safety consequences.

B. M2 – Enterprise-Wide Virtual Driver Safety Training Program

This mitigation would implement a Virtual Driver Safety Training Program for approximately all 12,700 SCE field and office employees. This virtual training program is designed to establish foundational principles of safe driving through an e-learning application. The courses are set up in 11 core modules, which would be assigned to the employees based on the driving environments associated with their job. The core courses include subjects such as looking ahead, scanning, understanding the surroundings, planning an "out," ensuring one's visibility to others on the road, backing up safely, and avoiding distractions. In addition, 12 mini-learning courses are assigned to reinforce the core modules. The deployment would occur over a three-year period, in groups of approximately 4,000 employees per year.

1. Drivers Impacted

The Virtual Driver Safety Training Program impacts D1 – People and D2 - Process. The virtual training will reinforce employees' rules of the road and enhance recognition of hazards to be aware of while driving. It provides a core set of principles to incorporate into the driving process as well as considerations for special driving conditions such as driving alone, in the dark, and under adverse weather conditions. It also emphasizes the preparation that is necessary prior to departing in a vehicle. Preparation includes steps such as vehicle inspection.

2. Outcomes and Consequences Impacted

The Virtual Driver Safety Training Program does not directly impact the outcome or safety consequences.

VI.

FOUNDATIONAL ACTIVITIES

SCE has determined that there are three key foundational activities that support the employee controls and mitigations discussed above, as well as other potential future controls and mitigations. These three activities are a Risk-Based Safety Program, a Safety Management System (SMS) and an Incident Management System (IMS).

A. F1 – Risk-Based Safety Program – Selected Mitigations for Planning and Implementation

1. Overview

The SCE Risk-Based Safety Program will support SCE in making progress towards eliminating SIFs by proactively, programmatically, and systematically evaluating risks and mitigating them. The Risk-Based Safety Program, in conjunction with key stakeholder and subject matter experts across SCE, looks to employ engineering-, organizational-, and human/process-based mitigations.

Additionally, the Risk-Based Safety Program will focus on proactively and comprehensively identifying SIF exposure (including drivers) and proactively preventing those incidents that result in catastrophic safety consequences. The Program is based on Operational Learning Principles adopted by high reliability organizations, the National Safety Council, the North America Transmission Forum, our peer utilities across North America and around the world, and high-risk organizations around the world such as Alcoa and Quanta. The Principles are as follows:

1. People make mistakes;
2. Blame fixes nothing;
3. Context drives behavior;
4. Learning and improving is vital; and
5. Leader's response matters.

In 2022 the initiative will continue to engage key stakeholders[22] across the organization for alignment, to maximize effectiveness and sustainability of the funded risk mitigations as they are implemented, and to develop a Five-Year Roadmap. Long-term, the initiative will proactively set standards for how work across SCE is executed and integrated in accordance with best practices, analytics, tools and technology. The initiative will also focus on strategically identifying and addressing risks based on exposure and potential, as well as incidents, drivers and conditions. Unknown risks would be brought to light by collaborating with those closest to the work, examining cause reports, assessing

[22] This includes frontline employees and supervisors, Line Leadership, Executives, assigned risk mitigations OU Points of Contact/Project Managers (POCs/PMs), Engineering, Enterprise Risk Management (ERM), Edison Safety, Training, and others.

recorded PSIFs/Close-Calls, and reviewing any documentation that could lead us to identify risks we have yet to capture. Benchmarking across the industry to gather peer utility experience with regard to the risks that these utilities faced when they performed similar work, will also assist us in identifying risks.

2. <u>Rationale for Inclusion as Foundational</u>

SCE believes this work is foundational to the risk mitigations that will or are being developed to mitigate employee safety risks. This work does not directly reduce SIFs. However, it will support future risk mitigation efforts. Specifically, SCE is in the process of establishing a 5-Year Roadmap that outlines the objectives and yearly plans to ensure alignment, engagement and commitment from key stakeholders across the organization so that we can sustain and continuously improve in our efforts.

The Roadmap will include year-by-year milestones for: (1) Implementing the prioritized risk mitigations as selected and funded, (2) Developing and refining a SIF Risk Register to help us understand the universe of risks, drivers and exposures, and then appropriately integrate with the Enterprise Risk Register; and (3) For data integration purposes, building Program/Organizational capabilities with roadmap objectives prioritized to account for stakeholder alignment, readiness, resource requirements and impact. Data integration includes the following Enterprise Risk Management objectives with key dependencies: (a) Establish framework for identification, linkage, and monitoring of risk data across the enterprise; (b) Develop framework to account for data readiness and accessibility; and (c) continuously refine Risk Register using a structured process of ongoing data analysis, SME challenge sessions, and senior management review.

At the Program level, SCE will implement risk mitigations as follows:

- SCE will assign risk mitigation OU mangers for each risk mitigation that has been prioritized. These managers will make progress towards implementation. They will plan, implement, and sustain the mitigation. They will also execute the evaluation of the risk mitigation's effectiveness and draw comparisons against established success measures. Finally, they will assess overall impact and opportunities for improvement to continue to reduce the risk over time.

- As touched on above, SCE will continue to refine the SIF Risk Register to prioritize and address future risks as needed and integrate it as appropriate with the Enterprise Risk Management Risk Register.
- SCE will collaborate with OUs and key stakeholders across the company to perform additional risk evaluations as necessary and identify risk mitigations (including implementation, evaluation and sustainability plans with resource requirements) to address High Energy Serious Injury and Fatality (HSIF), Low Energy Serious Injury and Fatality (LSIF) and Potential Serious Injury and Fatality (PSIF) drivers and gaps.

3. <u>RSE Cost Allocation Methodology</u>

SCE anticipates rough order-of-magnitude costs of approximately $1.5 million a year for the foundational Risk-Based Safety Program activities from 2022 – 2024 to accomplish the plan as outlined above. SCE will continue to refine priorities and cost estimates. We currently plan to provide an update in our 2025 GRC on the risk mitigations (multi-year initiatives with resource requirements) that will be prioritized to launch, implement, and sustain each year.

B. <u>F2 – Safety Management System</u>

The Z10 standard represents the first U.S. consensus standard on Occupational Health and Safety Management Systems. It was developed by the American National Standards Institute (ANSI) accredited standards committee, composed of over 40 members from industry, labor, government, and other organizations. Using this voluntary standard provides SCE with an effective tool for continually improving our occupational health and safety performance, as well as a framework for sharing and communicating with other entities regarding best practices.

In March 2018, SCE's CEO delivered a presentation at the CPUC *En Banc* meeting on safety. He indicated SCE's safety management system (SMS) was generally based upon the ANSI/ASSE Z10-012 standard. He grouped the 21 elements of the standard into 5 broad categories and provided examples of how SCE's safety programs filled out each of these categories. The categories and program examples were:

- Management Leadership and Employee Participation (Examples: Executive Safety Council, Safety Observation Program, Safety Recognition Programs, Craft-Driven Safety Program);
- Planning (Examples: Enterprise Risk Management, Cause Evaluation);
- Implementation and Operation (Examples: Overhead/Underground/and Grounding manuals, Tool Team, Chemical Management Team, Safety Communications including newsletters and informational bulletins/ roundtable discussions and video presentations/ communications to contractors through ISNetworld/ close call-incident reporting processes);
- Evaluation & Corrective Action (Examples: Safety Observation Program, EHSync Incident Reporting); and
- Management Review (Examples: Safety Culture Assessment, Triennial Assessment and Review of Safety Standards).

In 2019, the ANSI/ASSE Z10 standard underwent significant revisions.[23] Separate from the ISO 45001 harmonization effort, the 2019 revision also noted that numerous occupational health and safety advancements have occurred since the 2012 revision. To make sure we remain aligned with the revisions to the ANSI/ASSE Z10-2019 standard, SCE began considering the new standard modifications in 2020, just as the COVID-19 worldwide pandemic hit. This emergent event caused an immediate need to redirect key health and safety resources to address the control and spread of the virus at work and keep our employees and communities safe. As these needs lasted through late 2021, progress on the evaluation of SCE's SMS to ANSI Z10-2019 was also halted until late 2021.

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[23] The revision noted, "While it is not the intent of this document to duplicate requirements covered in ISO 45001, this standard provides a level of alignment and interpretation of those requirements relative to a U.S. perspective on the ISO standard." The revision added a section called "Context of the Organization – Strategic Considerations" to consider internal and external issues when planning. It also added a section called "Support" which provided requirements for resources, education, training and competence, communication, and document control. Finally, it broadens the definition of "employee" with a definition of "worker" which includes certain workers who are not employees of SCE.

1. <u>SCE Planned Engagement with External Consultants in 2022 - 2024</u>

Given the continued uncertainty of internal resources due to the ongoing threat of COVID virus variants, a decision was made to engage external consultants to assess in detail SCE's SMS and its alignment with the ANSI Z10-2019 standard. Engaging external consultants also offers the additional benefit of an independent set of eyes and an unbiased look at SCE's SMS.

Several key success factors and objectives have been identified by SCE for the revision of the SMS to align with the latest ANSI revision. These include:

- Having the support of the CEO, senior leadership team, and managers and employees to implement a standardized framework for managing safety risks;
- Using the standard's framework to evaluate the effectiveness of SCE's current practices and safety programs related to risk control: (a) identify workplace risks and existing controls; (b) classify and prioritize those risks based on frequency, severity and impact on SCE's operations; and (c) mitigate or control risks; and
- Having the structure in place to perform self-assessments, audits, and monitoring of progress to support continuous improvement.

To achieve these objectives, SCE will work with the external consultants to:

- Perform an extensive gap analysis between existing SCE policies, programs, procedures, work practices, preventive/corrective action programs and the Z10 system standard framework;
- Conduct a limited number of field assessments to develop a representative operational risk profile, determine compliance with industry-specific regulations and company policies, and make a general assessment of company safety culture based on observation of employee work practices;
- Develop an action plan that specifies the work products that need to be developed and implemented, and clarifies the roles and responsibility for completing each action;
- Develop a communication strategy that prepares the organization for initial phases of the Z10 implementation, and reinforces progress and benefits on a continuing basis;

- Develop and provide communications to explain Z10 requirements, and explain roles and responsibilities to identified managers, supervisors, and other employees;
- Develop policies, programs, work instructions, document control systems and audit protocols as identified in the gap analysis to support the SMS; and
- Develop executive-level training seminars for the leadership/management team, to provide executives with an understanding of their roles and responsibilities in leading and supporting continuous improvement under the new system.

Five phases are planned for this engagement. The phases are:

- Phase 1: Perform gap analysis against the Z10 standard;
- Phase 2: Develop the Implementation Plan;
- Phase 3: Begin implementation and develop work products;
- Phase 4: Complete implementation of management system components; and
- Phase 5: Reassess and develop future action plan.

We realize that business needs and focus may evolve over time. Accordingly, a leadership review will be performed at the end of each phase to make sure that the organization is aligned and moves in unison to the next milestone. If the leadership review deems it necessary, we will take appropriate steps modify the path for this engagement.

2. <u>SCE Targeting SMS Certification in 2025 – 2027</u>

Our goal is that, once we have completed the phases discussed above, SCE's SMS should be fully aligned with the ANSI/ASSP Z10-2019 standard. However, being aligned to a standard is not the same as being certified to a standard. Alignment with a standard means that an organization has looked at the requirements of the standard and assessed that their SMS meets them. The alignment approach can result in different levels of adherence to the standard's requirements, depending on how the organization interpreted and applied the requirements.

In contrast to alignment, being *certified* to a standard means that an independent third-party certification body, one that has been approved by the standard's accreditation board, has examined the organization's SMS with the rigor of an audit. And it means that after such scrutiny, the certification body has expressly pronounced that the organization's SMS meets the standard. In addition, the certification runs for a period of time, generally three years. At the conclusion of this timeframe, the organization's SMS must be re-audited by the independent registrar to maintain certification.

As a result, organizations whose SMS is certified to a standard are considered as more rigorously consistent with industry-wide practice when compared to other organizations whose SMS is simply self-classified as compliant. For these reasons, regulators and customers may prefer third-party affirmation of an organization's system rather than self-declared compliance.

After SCE leadership considers the totality of business needs at the appropriate juncture in this process, SCE will determine the cost and resource needs to obtain certification of its SMS and will decide at that time whether it is prudent to pursue certification. If a decision is made to pursue certification, SCE will select and work with an independent and qualified third party for certification.

3. Rationale for Inclusion as Foundational

Although it does not directly reduce the consequences or the likelihood of risk events, the SMS initiative supports several controls. Evolving SCE's current SMS into one that aligns with a national voluntary consensus standard supports the Safety Cultural Transformation effort of moving the organization from a Public and Private Compliance posture into one that is instead based on the concepts of Stewardship and Citizenship. The ANSI/ASSP Z10-2019 standard has components that include employee participation and focus on continuous improvement. These are considered essential ingredients for maturing an organization's safety culture.

In addition, the standard contains provisions to report, investigate, analyze, document and communicate incidents supported with a level of documentation commensurate with the risk. This supports the Incident Cause Evaluation control. Finally, the standard has provisions supportive of the HOP control. The standard integrates the concept of learning and improving through committed leadership and employee participation. This buoys HOP concepts.

4. RSE Cost Allocation Treatment

SCE anticipates some amount of costs for the implementation of the SMS as described above to be incurred in 2022–2024. However, at this time, SCE does not have the cost estimates developed for SCE's next rate case cycle (2025 – 2028). The 2022 – 2024 costs would be considered sunk costs and are not allocated to any controls and mitigations for purposes of RSE calculations. To the extent that SCE is able to identify any of the annual licensing or potential future system enhancements, SCE will include those items in RSE calculations for any controls or mitigations that they support in the Test Year 2025 GRC.

C. F3 - Incident Management System (IMS)

1. Overview

An incident management system (IMS) is a software solution that supports the entire incident management lifecycle. It allows incidents to be reported, evaluations to be managed, and corrective action plans to be monitored. The application offers comprehensive web and mobile data collection features, and advanced reporting and data analysis capabilities. Incidents can be recorded with multiple impacts (human, environment, media, etc.) to reflect a wide range of incident categories and subsequent management by different teams. Incident forms as well as their workflows and notifications can all be configured to fit business processes at a local and global level.

An IMS includes the following capabilities:

- Employee and contractor incident management
- Corrective and preventive actions
- Inspection management
- Observations
- Mobility

2. Rationale for Inclusion as Foundational

SCE believes that an IMS is a foundational tool that supports the programs detailed within the SMS. Data collected and reported by the IMS will aid in understanding where the SMS is performing well and where improvements can be made. The IMS also supports SCE's cause evaluation and corrective action process, facility inspections related to hazard identification, and safety observations. The IMS is a critical tool in culture monitoring, as increased reporting will allow development of "Culture Trend Codes." The use of these codes allows for a "real-time" view of culture change as incidents are reported and hazards mitigated.

The IMS enables the Risk-Based Safety Program and Safety Predictive Initiative through trend codes, allowing for a form of risk registry to be created as well as machine learning established. By using the same trend codes for observations and incidents in the IMS, the Risk-Based Safety Program and Safety Predictive Initiative can determine if observations related to specific hazards are occurring and if the count of exposures to that hazard are dropping. The program will also identify all corrective actions associated with a hazard.

3. RSE Cost Allocation Treatment

Currently SCE plans to select a vendor in 2022 followed by designing and building the system. In 2023, SCE plans to roll out and stabilize the IMS. In 2023 and beyond, there may be annual licensing fees and potential system enhancements. However, those costs will not be known until we select the final vendor or future system enhancements are firmly identified. Currently, SCE estimates that the annual spend for IMS in 2022 and 2023 will be approximately $2.4 million dollars per year. Since these costs will be incurred prior to SCE's next rate case cycle (2025– 2028), these are considered sunk costs and are not allocated to any controls and mitigations for purposes of RSE calculations. To the extent that SCE is able to identify any of the annual licensing or potential future system enhancements, SCE will include those items in RSE calculations for any controls or mitigations that they support in the Test Year 2025 GRC.

VII.

PROPOSED PLAN

SCE has developed a Proposed Plan to mitigate this risk, as shown in Table VII-11 below. The pre- and post-LoRE, CoRE and risk scores for the Proposed Plan are summarized by tranche in Table VII-12 below.

Table VII-11
Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[24],[25]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Safety Culture Transformation	$1.68	-	127
C1 - T2	Safety Culture Transformation	$0.27	-	2,357
C1 - T3	Safety Culture Transformation	$0.44	-	1,241
C2 - T2	Incident Cause Evaluations	$0.74	-	604
C2 - T3	Incident Cause Evaluations	$0.46	-	336
C3 - T2	T&D Field Based Training	$9.71	-	94
C3 - T3	T&D Field Based Training	$16.15	-	28
C4	Human and Organizational Performance	-	-	
C5 - T2	Safety Predictive Initiative	$0.23	$0.45	336
C5 - T3	Safety Predictive Initiative	$0.37	$0.75	137
	Total	**$30.05**	**$1.20**	**-**

24 C4 – Human and Organizational Performance does not have an RSE. As indicated above in Section IV.D, SCE will endeavor to provide updates on this program next year, when we file our Test Year 2025 GRC Application.

25 Please refer to Employee Safety RAMP Risk Model (excel file) and WP. Ch. 9 – Employee Safety RAMP Financials.

Table VII-12
Pre and Post LoRE, CoRE and Risk Scores[26]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Employee Safety	7.80	0.1	1.00	7.80	0.1	1.00
T1 - Office Employees	1.18	0.1	0.15	1.18	0.1	0.15
T2 - Field - Lineman, Troublemen, etc.	4.10	0.1	0.53	4.10	0.1	0.53
T3 - Field - All Others	2.52	0.1	0.31	2.52	0.1	0.31

A. Overview

SCE's Proposed Plan reduces safety risks by implementing programs that are designed to directly reduce serious injuries and fatalities. In addition to continuing SCE's existing safety controls, this plan integrates with the safety culture transformation roadmap to reduce serious injuries and improve performance. SCE believes the selected controls (C1-C4) are aligned with the goal to reduce serious injuries and fatalities. This Proposed Plan reduces safety risk by implementing programs that are designed to mitigate the risk with regard to both field and office employees. SCE has the ability to adopt new technologies within the proposed plan to effectively mitigate workforce safety risks.

B. Execution Feasibility

SCE believes that the Proposed Plan is feasible. SCE has the ability to continue the existing efforts within this plan, and the new activities build on existing capabilities and can be informed by historical experience. For example, the training in the Human and Organizational Performance area (C4) integrates with other training subjects, and we have experience in the associated work and logistics. As described above, SCE has commenced this training program in 2020 but has not experienced issues with execution, with the exception of the fact that the COVID-19 pandemic led to a necessary pause in

[26] Please refer to Employee Safety RAMP Risk Model (excel file).

in-person sessions. SCE believes that implementing the program will significantly reduce the risks among employees.

C. <u>Affordability</u>

While the Proposed Plan costs $2.5 million less per year than Alternative Plans 1 and 2, it does provide slightly less overall risk reduction. SCE believes that the combination of existing and enhanced controls in the Proposed Plan represents a carefully judged balance of reducing safety risks on the one hand, but doing so at a prudent cost to our customers on the other hand. Also, as indicated above in Sections IV and VI, SCE is continuing to evaluate certain mitigations based on results from the Risk-Based Safety Program, as well as the Safety Predictive Initiative and Human and Organizational Performance controls. We anticipate providing an update in our upcoming 2025 GRC Application.

D. <u>Other Considerations</u>

The pace of organizational and programmatic changes in the safety areas has created a sense of "change fatigue" among SCE employees. SCE developed the Proposed Plan with this in mind.
The safety predictive model will allow employees to proactively mitigate various types of risks by establishing a stable foundation for future safety efforts. However, SCE appreciates that the sentiment of "change fatigue" could potentially affect the level of engagement with the controls found in the Proposed Plan. SCE plans to monitor and adjust implementation accordingly.

VIII.

<u>ALTERNATIVE PLANS</u>

SCE developed Alternative Plan #1 as shown in Table VIII-13. The pre- and post-LoRE, CoRE and risk scores are summarized by tranche in Table VIII-14.

Table VIII-13
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[27]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Safety Culture Transformation	$1.68	-	127
C1 - T2	Safety Culture Transformation	$0.27	-	2,335
C1 - T3	Safety Culture Transformation	$0.44	-	1,228
C2 - T2	Incident Cause Evaluations	$0.74	-	599
C2 - T3	Incident Cause Evaluations	$0.46	-	333
C3 - T2	T&D Field Based Training	$9.71	-	93
C3 - T3	T&D Field Based Training	$16.15	-	28
C4	Human and Organizational Performance	-	-	
C5 - T2	Safety Predictive Initiative	$0.23	$0.45	333
C5 - T3	Safety Predictive Initiative	$0.37	$0.75	136
M1 - T1	Expanded Industrial Ergonomics Program	$2.00		20
M1 - T2	Expanded Industrial Ergonomics Program	$0.50		51
	Total	**$32.55**	**$1.20**	**-**

[27] Please refer to Employee Safety RAMP Risk Model (excel file) and WP. Ch. 9 – Employee Safety RAMP Financials.

Table VIII-14
Pre- and Post-LoRE, CoRE and Risk Scores[28]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Employee Safety	7.75	0.13	0.99	7.75	0.13	0.99
T1 - Office Employees	1.18	0.13	0.15	1.18	0.13	0.15
T2 - Field - Lineman, Troublemen, etc.	4.07	0.13	0.53	4.07	0.13	0.53
T3 - Field - All Others	2.50	0.13	0.31	2.50	0.13	0.31

A. Alternative Plan #1

1. Overview

Alternative Plan #1 includes all of the controls and mitigations from the Proposed Plan, plus the addition of M1, an Expanded Industrial Ergonomic Program. The Expanded Industrial Ergonomic program is a multi-pronged approach to help employees maintain physical ability to safely meet the physical demands of the work, address early signs and symptoms of an injury, and identify and mitigate hazards that lead to serious and non-serious musculoskeletal injuries.

2. Execution Feasibility

SCE does not currently foresee any implementation issues for this program, but we may need to consider the pace and scope of organizational change management efforts, in order to sustain engagement for optimal program performance. SCE also has identified vendors capable of implementing this program at SCE. However, given the current state of the COVID-19 pandemic and future uncertainties, there may still be challenges in implementing this program at the moment. However, SCE plans to continue to explore Alternative Plan #1's additional components for potential inclusion in the Test Year 2025 GRC.

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28 Please refer to Employee Safety RAMP Risk Model (excel file).

3. Affordability

Alternative Plan #1 has an increased cost of $2.5 million per year over the Proposed Plan. At this time, the Alternative Plan does not appear to provide significant risk reduction for serious injuries and fatalities compared to the Proposed Plan.

4. Other Considerations

SCE did not identify any other considerations related to this program.

B. Alternative Plan #2

SCE developed Alternative Plan #2 as shown in Table VIII-15. The pre and post LoRE, CoRE and risk scores are summarized by tranche below in Table VIII-16.

Table VIII-15
Alternative Plan #2 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[29]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Safety Culture Transformation	$1.68	-	126
C1 - T2	Safety Culture Transformation	$0.27	-	2,349
C1 - T3	Safety Culture Transformation	$0.44	-	1,237
C2 - T2	Incident Cause Evaluations	$0.74	-	602
C2 - T3	Incident Cause Evaluations	$0.46	-	335
C3 - T2	T&D Field Based Training	$9.71	-	93
C3 - T3	T&D Field Based Training	$16.15	-	28
C4	Human and Organizational Performance	-	-	
C5 - T2	Safety Predictive Initiative	$0.23	$0.45	335
C5 - T3	Safety Predictive Initiative	$0.37	$0.75	137
M2 - T1	Enterprise Wide Virtual Driver Safety Training Program	$2.00		2
M2 - T2	Enterprise Wide Virtual Driver Safety Training Program	$0.38		40
M2 - T3	Enterprise Wide Virtual Driver Safety Training Program	$0.13		64
	Total	**$32.55**	**$1.20**	**-**

[29] Please refer to Employee Safety RAMP Risk Model (excel file) and WP. Ch. 9 – Employee Safety RAMP Financials.

Table VIII-16
Pre and Post LoRE, CoRE and Risk Scores[30]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Employee Safety	7.8	0.128	0.99	7.8	0.128	0.99
T1 - Office Employees	1.18	0.125	0.15	1.18	0.125	0.15
T2 - Field - Lineman, Troublemen, etc.	4.09	0.130	0.53	4.09	0.130	0.53
T3 - Field - All Others	2.51	0.125	0.31	2.51	0.125	0.31

1. Overview

Alternative Plan #2 expands upon the controls and mitigations in the Proposed Plan. It adds M2 - Enterprise-Wide Virtual Driver Safety Training Program for all of SCE's approximate 12,700 employees (represented and non-represented). Although the virtual training may address knowledge gaps for some employees and provide additional educational reinforcement of safe driving concepts, it does not appear at this time that this alternative plan will significantly reduce SIFs related to driving. Most of the SIF incidents are related to driver skills, which are more effectively addressed with actual "hands-on" type training rather than remote training. SCE may explore a "hands-on" type driver training effort for select SCE employees for potential inclusion in the 2025 GRC. We will provide an update in the 2025 GRC if we do institute this additional training component.

2. Execution Feasibility

Alternative Plan #2 would be delivered through a virtual setting for represented and non-represented employees. SCE has identified a potential vendor that can provide this remote learning experience.

30 Please refer to Employee Safety RAMP Risk Model (excel file).

3. Affordability

Alternative Plan #2 would entail an incremental cost of $2.5 million per year over the Proposed Plan with little to no concrete risk reduction, given the remote nature of the training and unclear or relatively minor projected reduction in SIFs.

4. Other Considerations

SCE did not identify any other considerations related to this program.

IX.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

Below SCE describes several lessons learned from both our previous RAMP and from feedback on other IOU RAMP submissions.

1. SCE Further Tranched Field Employees Based on Risk Exposure

When reviewing feedback from the Commission's Safety Policy Division on Sempra's 2021 RAMP report, SPD noted that not all employees share the same risk profile. SPD recommended at a minimum that tranching could include, for example, office-only employees and field employees; SPD also suggested that further differentiation by type of work could be attempted.[31]

As discussed above in Section II.F, SCE has followed this guidance. We tranched our employees based on office and field employees. SCE then further tranched the field employees into two additional categories: 1) Lineman/Journeyman, Apprentice, Troubleman and Groundman; and 2) all other field employees.

2. The Inclusion of Potential Serious Injuries and Fatalities into the MAVF Framework Proved Challenging

SCE is committed to reducing safety incidents throughout the workplace. This includes actual serious injuries and fatalities (SIF), potential SIFs (PSIFs) and minor injuries. As described above, SCE has multiple controls and mitigations to help ensure that SCE provides a safe workplace

[31] *See* Safety Policy Division Staff Evaluation Report on SDG&E's and SoCalGas' Risk Assessment and Mitigation Phase (RAMP) Application Reports, p. 72.

while preventing SIFs in accordance with applicable laws, regulations, and best business practices. In order to capture the safety risk to our employees and contractors, SCE attempted to integrate PSIFs into the MAVF for this RAMP. However, SCE experienced two major challenges trying to incorporate PSIF incidents into the MAVF, as described below.

First, SCE did not find a useful methodology to incorporate PSIF incidents into the consequences of the risk bowtie. While SCE does have the same level of detail on potential incidents (driver, sub-driver, tranche, etc.) as actual incidents for certain bow-tie elements (driver, sub-driver, tranche), it was unclear what consequence scoring those incidents should be given in the MAVF. For instance, the consequences of a serious injury are weighted at half the value of a fatality. SCE could not discern any current industry-accepted or consensus methodology concerning the weighting of a *potential* SIF as compared to an actual SIF.

SCE will continue to investigate methodologies for incorporating PSIFs into the MAVF. If further exploration leads to a workable and accurate approach, we would seek to include that additional layering in our 2025 GRC Application. SCE is also open to discussions with parties in the Risk OIR proceeding concerning appropriate methodologies or approaches for specifically incorporating PSIFs into the MAVF framework.

Second, the inclusion of these PSIF incidents would be inconsistent with how other risks are evaluated. For instance, it is near-impossible for SCE to include potential serious injuries or fatalities to the public if we are unaware that they occurred. To take a practical example, if a member of the public almost gets electrocuted while breaking into our facility to steal copper wire, but no electrocution event or incident actually occurs, SCE may not even have awareness of the "almost" aspect of the situation. This is a limitation that would apply to other utilities as well who may be in a similar situation.

Moreover, inclusion of the PSIFs at this time may lead to intervenors or other stakeholders asserting that the risk scores are "inflated" because potential incidents rather than actual ones are driving the scores up. Parties may strenuously disagree as to what constitutes a possible incident and what does not. In other words, parties may have differing views on what was enough of a "close call" that inclusion of the item (and corresponding increase in the risk score) is warranted.

Thus, if SCE for example included PSIFs for employee and contractor incidents, it may lead to stakeholders feeling that the risk scoring for the Employee and Contractor Safety risks appears to be overstated compared to other RAMP risks.

SCE takes every safety incident seriously, whether it is relatively minor (such as a slip or fall resulting in a DART-level incident) or serious (such as a switching incident with a flash, resulting in third-degree burns suffered). Further, SCE treats PSIF incidents in the same manner as actual SIF incidents because in many cases, a PSIF could have resulted in an actual SIF to an employee. While the consequence of actual SIF and PSIF incidents may have been different, the circumstances are often very similar, such that an actual SIF could have occurred. Cause evaluations are performed on actual and potential SIFs to identify and implement corrective actions to reduce the risk of future, similar incidents.

Thus, when SCE makes efforts to address drivers of incidents, SCE examines PSIF incidents with the same degree of seriousness as actual SIF incidents. We note that an indirect result of *not* including PSIFs in the MAVF is that the actual benefits of the proposed controls and mitigations may be understated, since the benefits of reducing PSIFs have not been incorporated.

3. Determining Mitigation Effectiveness Values Still Proves Challenging

SCE's overall employee safety program consists of an assemblage of mitigation programs targeting the key drivers of employee safety incidents. Results of individual mitigation measures are not easily measurable on their own, as they are often symbiotic and reliant on each other to be successful. Developing this RAMP Risk chapter required us to take a quantitative approach to understanding each control or mitigation's effect on drivers, outcomes, and consequences. This was challenging in many cases (e.g., quantifying the impact of safety cultural change). The relatively small number of SIF incidents per year (~11.5) make statistical trending difficult in the short term. However, we believe the combined program mitigations should result in a demonstratable reduction in employee SIFs over a period over several years.

B. Data Collection and Availability

Since the 2018 RAMP, SCE has improved the trending of safety-related incident causes, activities, human performance, SIF Exposure, energy sources and controls for safety data analysis.

SCE reviewed information and assigned appropriate trend codes on safety incidents for serious injuries and fatalities, as well as potential serious injuries and fatalities. This is more conducive to analyzing a wider body of data. However, obtaining data on the financial costs of safety incidents (other than costs linked directly to the injury such as medical and worker's compensation) was also challenging. Despite our efforts since the 2018 RAMP, some of the data analysis performed for this chapter still required manually transposing and interpreting data across several datasets. SCE continues to enhance our predictive modeling and cause evaluation efforts, along with data collection systems, so that we continue to advance our safety analyses and risk mitigation approaches.

C. Performance Metrics

SCE tracks a significant amount of data related to employee safety incidents. Table IX-17 below summarizes some key performance metrics; however, this is not an exhaustive list. The table also indicates whether any of these metrics are included in SCE's annual Safety Performance Metrics (SPM) report[32] and if there is any relationship to the RAMP bowtie and/or risk analysis. SCE attempted to include a combination of leading and lagging indicators.

[32] This is based on the updated list of Safety Performance Metrics from D.21-11-009, Appendix B.

Table IX-17
List of Employee Safety Performance Metrics

Metric	Leading / Lagging Indicator	Included in SPM Report	Metric Directly Included in Risk Bowtie	Description
Employee SIFs - Actual (Count and Rate)	Lagging	Yes	Yes	Count and Rate of incidents that resulted in a serious injury or fatality to an SCE employee as defined by the Edison Electric Institute (EEI) SIF criteria. This includes HSIF and LSIF incidents, per the EEI Safety Classification and Learning (SCL) Model. This directly informs the triggering event frequency of the risk bowtie.
# of Employees	-	Indirectly	Yes	The number of employees informs the risk exposure and the hours employees work are used in calculating SIF rates.
Employee Potential SIFs - (Count and Rate)	Leading / Lagging	Yes	No	Count and Rate of incidents that resulted in a potential serious injury or fatality to an SCE employee as defined by the EEI Safety Classification and Learning (SCL) Model. Currently these incidents are not included in the bowtie.
Employee DART Rate / Count	Lagging	Yes	No	DART injuries are determined based on number of Occupational Safety and Health Administration (OSHA)-recordable injuries resulting in Days Away from work and/or Days on Restricted Duty or Job Transfer. DART rate is calculated using actual work hours and is standardized by using a factor of 200,000, which represents the average number of hours worked by 100 full-time workers in one year. This is currently not included in the risk analysis but is a good indicator of overall injuries and injury rate.
# of Safety Observations	Leading	No	No	Count of safety observations submitted by SCE employees. Safety observations are a tool to engage in safety conversations, proactively identify and correct at-risk safety behaviors or unsafe conditions, recognize positive safety behaviors, and share lessons learned and best practices.

X.
ADDRESSING PARTY FEEDBACK

In reviewing SCE's 2018 RAMP report, Cal Advocates suggested that SCE evaluate and present potential consequences for actions without adverse outcomes, since events without adverse outcomes may represent near-miss events.[33] In response to Cal Advocates' recommendation, SCE had noted that we will consider this recommendation when developing our next RAMP report.[34] As discussed above in Section IX.A.2, while SCE necessarily focused the bowtie and risk analysis on actual serious injuries and fatalities, SCE does agree that the inclusion of potential serious injuries and fatalities could be

[33] *See* I.18-11-016. -Comments of The Public Advocates Office on November 2018 Submission of Southern California Edison Company's Risk Assessment and Mitigation Phase, p. 4.

[34] *See* A.19-08-013. Exhibit SCE-11, Supplemental Testimony on Risk-Informed Strategy and Business Plan p. 17.

beneficial in more fully capturing the risk to our employees as well as the full benefit resulting from our controls and mitigations. We look forward to further discussion with stakeholders on what might serve as appropriate methodologies in future filings.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Contractor Safety

Chapter 10

Rosemead CA
May 13, 2022

Chapter 10: Contractor Safety

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I.

EXECUTIVE SUMMARY

A. Risk Overview

SCE contractors perform a variety of work, including certain high-hazard tasks that SCE does not regularly perform with its own employees. Some examples of the work performed by SCE contractors include Transmission and Distribution Line Construction, Vegetation Management, Hazard Tree Removal, Crane Operations, Traffic Control, Helicopter Operation, Drone Operations, Civil Operations (horizontal directional drilling and jack and bore), Substation Operation and Maintenance, Generation Maintenance, heavy civil equipment operation, Environmental Monitoring, Material Transport, and Corporate Real Estate.

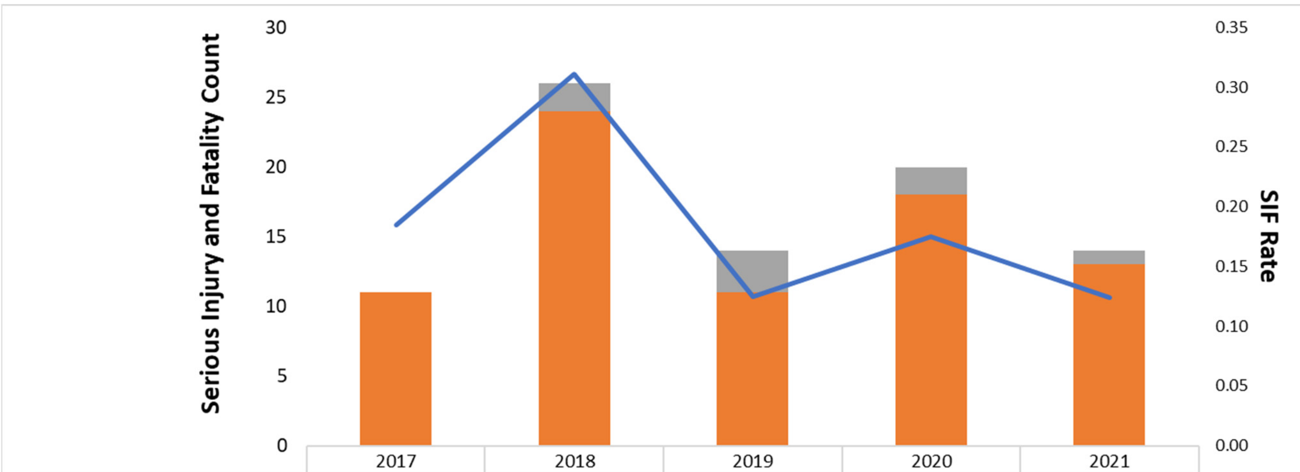
In the four years since SCE filed its first RAMP, SCE has continued to use outside contractors as warranted. In this chapter, SCE discusses actions we take to support our contractors in managing safety risks that can result from the following:

- Incorrectly executing work due to knowingly or unknowingly violating a procedure, policy, or rule;
- Failing to identify, correct, and/or account for hazardous conditions or work practices;
- Incorrectly operating a vehicle or equipment;
- Following incorrect processes or system designs;
- Ineffectively preparing (as between ground and air crews);
- Not being fit for duty, or being overly fatigued;
- Lacking necessary skills, training or qualifications.

This chapter analyzes incidents that occur in the field and in vehicles, including heavy equipment and aircraft. The chapter encompasses field incidents that involve electrical assets (e.g., working with energized equipment), and those that do not involve electrical assets (e.g., falling from a ladder).

SCE continues to utilize contractors and contractor hours for the highest-risk category (Safety Tier 1), and the hours have grown from 16.7 million hours in 2018 to 22.5 million hours in 2021. This steady increase in contractor workload represents an increased scope of risk for SCE and is expected to continue in the foreseeable future. Figure I-1 below shows that despite the significant increase in contractor hours and the attendant increase in the count of Serious Injuries and Fatalities (SIF), the SIF *rate* has decreased since 2018.

Figure I-1
SCE Historical Contractor Safety Performance



	2017	2018	2019	2020	2021
Tier 1 Fatality Count	0	2	3	2	1
Tier 1 Serious Injury Count	11	24	11	18	13
Tier 1 SIF Rate	0.18	0.31	0.12	0.17	0.12

Under independent contractor legal principles, SCE is generally not permitted to prescribe how contractors perform their tasks, and generally does not formally train them in how to do so. SCE instead has to hire contractors who can achieve certain results and do so in a legally compliant way. SCE sets standards to define the requirements for, and expectations of, our contractors. We also utilize various programs (described in this chapter) to monitor, track, and influence contractor's safety performance. The stated goal of SCE's Contractor Safety group is to eliminate serious injuries and fatalities from occurring in our contractor ranks.

SCE identified a number of controls to address this risk and threats.[1]

- This chapter describes one compliance activity related to various regulatory and legal requirements that necessitate the need for SCE to maintain safety standards, programs, and policies for the welfare of our employees.

This chapter evaluates three controls:

- Pre-Qualification and On-Boarding (C1): This includes activities concerning pre-qualifying and on-boarding contractors.
- Oversight, Performance Management and Culture Development (C2): This includes activities regarding performance management of contractor safety.
- Incident Management and Learning (C3): This includes activities on contractor safety incident management.

The Proposed Plan continues existing programs (C1, C2, & C3), and adds certain carefully-selected enhancements to specific important areas.

- Alternative Plan #1 represents continuing all existing controls in 2025 – 2028 as well as adding enhancements to maximize mitigation efforts in C2 – Oversight, Performance Management and Culture Development Control.
- Alternative Plan #2 represents continuing all existing controls, but without enhancing any program efforts in critical Control areas. Moreover, Alternate Plan #2 does not include efforts to replace existing third-party observation consultants with SCE in-house resources.

In the spirit of continuous improvement, SCE will continue to evaluate contractor safety programs, procedures, and staffing strategies to achieve desired safety performance and help reduce injuries by holding our contractors accountable for managing the safety of their own workforce.

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Contractor Safety based on the Proposed Plan discussed below.

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[1] C = Control. This is an activity performed prior to or during 2022 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report and are addressed in Section III.

Table I-1
Summary of Pre- and Post- LoRE and CoRE Risk Scores[2]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
Contractor Safety	**LoRE**	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
	13.05	0.17	2.17	10.38	0.17	1.72

II.

RISK ASSESSMENT

A. Risk Definition and Scope

In SCE's 2018 RAMP, SCE defined serious injuries and fatalities as either Life Threatening or Life Altering, based on internal severity assessment criteria. For SCE's 2022 RAMP, our risk definition for contractor safety is incidents involving SCE's contractors, potentially exposing contractor workers to hazards. This includes hazards arising from construction or maintenance activities, hazards arising from supporting activities, and vehicle incidents that result in a serious injury or fatality as defined using the Edison Electric Institute (EEI) SIF criteria.[3]

As shown below in Table II-2, the scope of risk does not include lower-level injuries such as sprains, strains, or Days Away Restricted or Transferred (DART) injuries. SCE considers SIFs to be the highest risk priority, and we focus our efforts on reducing SIFs. However, SCE does monitor and track monthly contractor DART incident counts as well.

The scope also excludes Potential SIFs (PSIFs) as defined by the EEI-SCL model.[4] Although the actual outcome of a PSIF does not include actual serious injuries, SCE exerts a similar amount of effort

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2 Refer to Contractor Safety RAMP Risk Model (excel file).

3 WP Ch. 10 – Edison Electric Institute (EEI) Serious Injury and Fatality (SIF) Criteria.

4 WP Ch. 10 - EEI SIF Safety Classification Learning (SCL) Model: For purposes of this RAMP analysis, a SIF would include incidents categorized as: (a) High-Energy Serious Injury or Fatality (HSIF) - Incident with a release of high energy in the absence of a direct control where a serious injury is sustained; and (b) Low-Energy Serious Injury or Fatality (LSIF) - Incident with a release of low energy in the absence of a direct control where a serious injury is sustained.

to identify and eliminate the cause(s) of PSIFs as if an actual SIF did occur. SCE's approach to addressing PSIFs is further discussed in Section VIII.A.

Table II-2
Scope of Contractor Safety Risk

In Scope	• Acts performed by either Safety Tier 1 or Safety Tier 1 HR contractor that led to a serious safety incident. A serious safety incident is defined as a serious injury and/or fatality as defined in the EEI SCL model (HSIF or LSIF).
Out of Scope	• Acts performed by an SCE contractor that led to potential serious injury as defined by the EEI SCL model (PSIF). • Lower-severity injuries such as sprains, strains, and/or DART injuries. • For purposes of this RAMP, "Contractor" excludes other types of Supplemental Workers such as Contingent Workers, Consultants, Professional services, and vendors who do not perform work on SCE property, e.g., offshore support services, material and food delivery, and pickup services that do not require the use of powered equipment.

The Exposure for Contractor Safety SIFs is defined as the amount of work per year performed by contractors, as each additional hour worked increases the risk of serious injury of fatality. For this RAMP application, SCE's highest-risk category (Safety Tier 1) is further split into two tranches based on risk level: Safety Tier 1 *Higher Risk (HR)*[5] and Safety Tier 1. The hours reported (exposure) for contractors in 2021 are shown in Table II-3 below. We also include additional details on the tranching approach below in Section II.F.

[5] Safety Tier 1 HR contractors are those personnel that perform scopes of work that have historically experienced a higher volume and severity of incidents on SCE property. Safety Tier 1 contractors perform work activities that are high risk and, without implementation of appropriate safety measures, are potentially hazardous or life-threatening.

Table II-3
SCE Contractor Hours By Risk Tranche

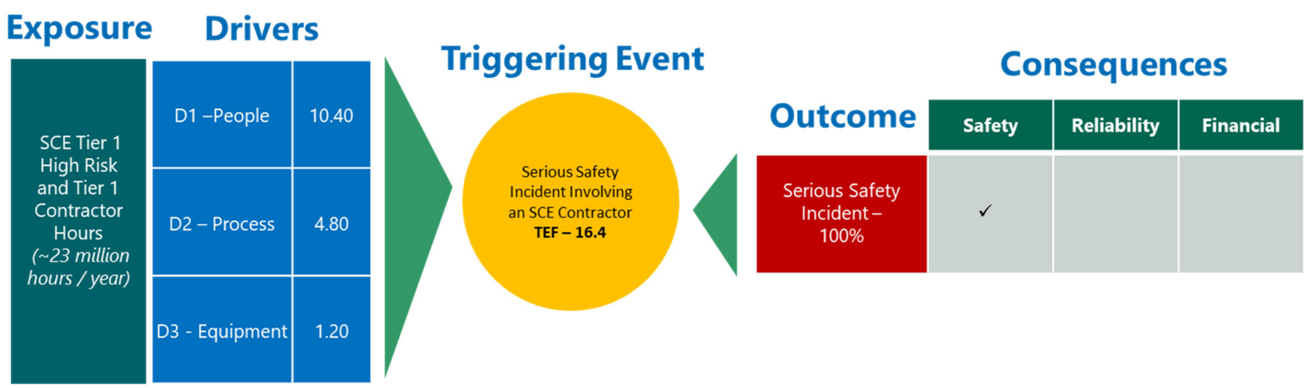
Contractor Risk Tranche	**Million Hours/year**	**% of Total Tier 1 Contractor Hours**
Tranche 1 - Tier 1- High Risk Contractors	16.1	71%
Tranche 2 - Tier 1 Contractors	6.5	29%
Total Contractor Tier 1 Hours	22.6	**100%**

B. <u>Risk Bowtie</u>

The 2018 RAMP combined employee and contractor safety in one RAMP chapter and bowtie analysis.[6] The 2022 RAMP application has broken this down to a greater level of specificity. We have separate bow ties and chapters for employee and contractor safety. Figure II-2 below presents the risk bowtie developed for Contractor Safety. The exposure for this risk is the number of Tier 1 High Risk and Tier 1 contractor hours worked.

[6] *See* SCE 2018 RAMP – Chapter 7, Employee, Contractor and Public Safety. In the 2022 RAMP, public safety risks are discussed throughout SCE's RAMP report. Examples include the following: Chapter 5 - Contact with Energized Equipment; Chapter 6 - Underground Equipment Failure; Chapter 4 - Wildfire and PSPS; and Chapter 12 - Hydro Dam Failure.

Figure II-2
Risk Bowtie for Contractor Safety[7, 8]



C. Drivers

After a contractor submits a safety incident report, an SCE safety professional assigns a SIF severity for each incident. This data is stored in an internal database called EHSync. The historical safety incident data from EHSync was used to populate the bow tie, as shown in Figure II-2 and further discussed below. For the bowtie, SCE identified all EEI-SIFs reported from 2017 - 2021.[9] Using SCE's trend code data, as assigned by an SCE safety analyst, each incident was then evaluated for a primary cause (sub-driver). These sub-drivers were then grouped into three major categories, People, Process, and Equipment. These three categories are described as follows:

- People: Incidents caused by human behavior
- Process: Incidents caused by inadequate process or process application
- Equipment: Incidents caused by the failure of equipment

Table II-4 below shows the historical driver frequency.[10]

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[7] Some of these events may have a potential financial consequence; namely, the potential costs of workers compensation claims and/or third-party lawsuits arising from the outcome(s) the programs and activities are designed to minimize and/or prevent. SCE has not included those potential consequences in this RAMP. This is consistent with SCE's past practice, appropriately maintains confidentiality, and protects attorney-client privileged information.

[8] Please refer to WP. Ch. 10 - Baseline and Risk Inputs.

[9] SCE began using EHSync to track contractor incidents in 2017, so we do not necessarily possess the same type and level of contractor SIF metrics for years prior to 2017.

[10] Please refer to WP. Ch. 10 – Mitigation Effectiveness and Driver Frequency.

Table II-4
Historical RAMP Driver Frequency

RAMP Driver	Total (2017 - 2021)	Annualized Frequency	% of Driver Frequency
D1 - People	52	10.4	63%
D2 - Process	24	4.8	29%
D3 - Equipment	6	1.2	7%
Total	**82**	**16.4**	**100%**

1. D1 - People

The sub-drivers in this category represent incidents where the primary cause was determined to be human performance. Brief descriptions of each driver are shown below, and the historical frequencies are displayed in Table II-5.

- *Hazard Identification Failure:* Contractor worker fails to recognize the hazards inherent in the work. Had the contractor recognized the hazards more effectively, mitigations could have been implemented and the incident may not have occurred at all, or may have occurred but with less serious consequences.
- *Human Performance / Not following rules*: Contractor worker fails to follow established safety rules or procedures. Had the rules or procedures been followed, the incident may not have occurred, or may have resulted in less serious consequences.
- *Complacency / Overconfidence*: Contractor worker was performing seemingly routine or familiar tasks, resulting in a lack of focus on safety. Had the contractor been more focused on working safely rather than focusing on just getting the task done, the incident may not have occurred, or may have occurred but with less serious consequences.
- *Perceived Time Pressure:* Contractor worker felt perceived time pressure, causing them to rush the work, resulting in unsafe conditions. Had they not felt rushed to

perform the work, the incident may not have occurred, or may have occurred but resulted in less serious consequences.

- *Fatigue:*[11] Contractor worker was not sufficiently rested before performing the task. Had they not been fatigued when performing the work, the incident may not have occurred, or may have occurred but with less serious consequences.
- *Understanding and compliance of STOP WORK authority:*[12] Contractor worker fails to call for work to stop when an imminent hazard is identified. Had the worker called a prompt stop to work at the time, the incident may not have occurred, or may have occurred but with less serious consequences.

Table II-5
Historical Sub-drivers for People Driver Frequency

People RAMP Sub-drivers	Total (2017 - 2021)	Annualized Frequency	% of People Driver Frequency
Hazard Identification Failure	35	7	67%
Human Performance / Not following rules	13	2.6	25%
Complacency / Overconfidence	3	0.6	6%
Perceived Time Pressure	1	0.2	2%
Total	**52**	**10.4**	**100%**

2. D2 - Process

The sub-drivers in this category are for incidents where the primary cause was determined to be inadequate process. We provide brief descriptions of each driver below, and the historical frequencies are displayed in Table II-6.

- *Lack of standards/skill/training/qualified contractor workers:* – incident was primarily caused by a lack of identified standards or by the use of contractor workers

[11] This specific driver did not have any historical incidents associated with an actual SIF event; however, it has been identified as a driver for an event that resulted in a PSIF. For further discussion on PSIFs, please refer to Section VIII.A.2.

[12] This specific driver did not have any historical incidents associated with an actual SIF event; however, it has been identified as a driver for an event that resulted in a PSIF. For further discussion on PSIFs, please refer to Section VIII.A.2.

who were not sufficiently trained in those standards. Had the standards been in place or the workers sufficiently trained, the incident may not have occurred, or may have resulted in less serious consequences.

- *Ineffective preparation/communications between ground and air crews*: – contract crews failed to communicate effectively as between aircraft crews and those working on the ground. Had the crews communicated more effectively, the incident may not have occurred, or may have resulted in less serious consequences.
- *Ineffective Traffic Management:* – incident was determined to be primarily caused by insufficient or ineffective traffic management systems. Had the appropriate traffic management system been in place, the incident may not have occurred, or may have resulted in a less serious outcome.
- *Unfamiliar conditions (e.g., wildfire, out of state workers):* – contract worker was working in unfamiliar conditions. Had they been familiar with the conditions in which they were working, the incident may not have occurred, or may have resulted in less serious consequences.
- *Ratio of safety observers to workers:* - – contractor workforce did not meet the required ratio of safety observers to contract workers, resulting in insufficient safety observation coverage. Had the ratio of safety observers to workers been sufficient to provide the required coverage, the incident may not have occurred, or may have resulted in less serious consequences.
- *Contractor Safety Culture:*[13] – The contractor company's safety culture was not at the required maturity level. Had the company safety culture been more mature, the incident may not have occurred, or may have resulted in less serious consequences.

[13] This specific driver did not have any historical incidents associated with an actual SIF event. However, it has been identified as a driver for an event that resulted in a PSIF. For further discussion on PSIFs, please refer to Section VIII.A.2.

Table II-6
Historical Sub-drivers for Process Driver Frequency

Process RAMP Sub-drivers	Total (2017 - 2021)	Annualized Frequency	% of Process Driver Frequency
Lack of standards/skill/training/qualified workers	14	2.8	58%
Ineffective preparation/communications between ground and air crews	5	1	21%
Ineffective traffic management	2	0.4	8%
Unfamiliar conditions (e.g. wildfire, out of state workers)	2	0.4	8%
Ratio of safety observers to workers	1	0.2	4%
Total	**24**	**4.8**	**100%**

3. D3 - Equipment

The Equipment driver category is defined as a failure in equipment design that leads to an incident, or equipment design that creates an error trap for individuals and leads to an incident. Table II-4 shows the annual frequency of this driver. SCE does not have any cause codes or sub-drivers for this specific driver category.

D. Triggering Event

The triggering event is defined as a serious safety incident involving an SCE contractor. The triggering event frequency is composed of the estimated annual frequencies of D1 – D3, as shown in Table II-4 above.

E. Outcomes and Consequences

For purposes of this RAMP, SCE has identified one outcome: a serious safety incident. SCE utilizes the Electric Energy institute (EEI) SIF criteria to capture incidents that results in a serious injury or fatality. SCE did not include any financial or reliability consequences associated with this outcome. SCE does not consider any potential reliability consequences related to SIF to be material. The cost impacts of potential financial consequences (e.g., litigation) are not included in the bowtie or RSE calculations.

F. Tranches

Based on the level of risk associated with the work contractors perform, two tranches have been assigned: 1) Safety Tier 1 Higher Risk (HR) and 2) Safety Tier 1. Contractors in both groups perform work for SCE that is subject to serious injuries or fatalities if behaviors and/or work practices deviate from established safety protocols and best practices. Safety Tier 1 HR contractors are those performing work scopes that have historically experienced a higher volume and severity of incidents on SCE property.

Safety Tier 1 HR is comprised of the following work types:

- Vegetation Management
- Overhead Distribution
- Substation construction
- Transmission
- Underground Civil
- Air Operations
- Crane Operations
- Traffic Control
- Others as determined by the OU

Safety Tier 1 – A designation assigned to contracted work activities that are high risk and, without implementation of appropriate safety measures, are potentially hazardous or life-threatening.

Examples of Safety Tier 1 work types include the following:

- Generation
- Engineering Services
- Corporate Real Estate
- Inspection Services
- Telecomm

Table II-7 below summarizes the tranche level risk exposure for contractor safety.

Table II-7
Tranche Level Risk Exposure[14]

Tranche ID	Tranche Description	Exposure (Contractor Hours)	Percent Exposure	LoRE / TEF	% of TEF
T1	Tier 1 Higher Risk	16,078,643	71%	14.6	89%
T2	Tier 1	6,486,554	29%	1.8	11%
Total		**22,565,197**	**100%**	**16.4**	100%

G. Related Factors

For purposes of this discussion, SCE defines related factors as factors that are not directly included in the risk modeling but can impact the driver frequency and/or the likelihood of certain outcomes. One key related factor for Contractor Safety is the type and amount of work that is performed by SCE contractors. The type of work that SCE will contract out and the extent/scope of that work will directly influence the risk exposure for both contractor and employee safety risks. For purposes of this RAMP analysis SCE has assumed a constant contractor workforce in terms of hours worked and work types as described above in Section II.F

III.
CONTROLS

SCE has programs and processes in place that help control the risk today. Three controls are modeled in this risk analysis and are shown below in Table III-8.

[14] Please refer to WP. Ch. 10 – Baseline and Risk Inputs.

Table III-8
Inventory of Contractor Safety Controls[15]

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP? Control	Included in Proposed and/or Alternative Plans?
C1	Pre-Qualification and On-Boarding	D1, D2	-	-	Partially included in C2 - Contractor Safety Program	All
C2	Oversight, Performance Management and Culture Development	D1, D2, D3	-	-	No	All
C3	Incident Management and Learning	D1, D2	-	-	No	All

SCE's Contractor Safety Management Program is focused on enhancing SCE's safety oversight of contractors/subcontractors, reinforcing SCE's expectations that the contractor's leadership communicate SCE's requirements to the contractor's workforce while reasonably managing the safety risks associated with contracted work. SCE has multiple workstreams to address contractor safety. These workstreams are grouped into three major categories: (1) Pre-Qualification and On-Boarding; (2) Oversight, Performance Management and Culture Development; and (3) Incident Management and Learning. The program components are listed below in Table III-9 and include safety pre-qualification of all contractors/subcontractors that are conducting high-risk work, oversight of contractor work planning process, field monitoring, incident analyses, safety performance improvement processes for individual contractors, and efforts to influence the development of strong safety cultures amongst our contractors.

15 Please refer to WP. Ch. 10 – Baseline and Risk Inputs.

Table III-9
SCE Contractor Safety Program By Control

Pre-Qualification and On-Boarding	• 3rd party (ISN Qualification), • Conditional Contractor Plans, • RFP Development, • Contractor Orientation (CHOC HASP), • Badging and Training Qualification
Oversight, Performance Management and Culture Development	• SCE Field Observations, • 3rd party field observations, • COA implementation, • CSQAR, • Work Type CSQAR (COA development), • Scorecards, • Performance Dashboards and Monthly reporting, Compliance Management, • Control Stages, • Safety Culture Training, • Communications, • Safety Forums, • Contractor Safety Advocate, • California Peer Utility Benchmarking Forums
Incident Management and Learning	• Incident Evaluations, • Management Review Committees, • Common Cause Evaluations, • Corrective Action Plan Management, • Incident Review Teams, • Incident Communications

A. C1 – Pre-Qualification and On-Boarding

The programs identified in C1 Pre-Qualification and On-Boarding, are in place to minimize the potential for SIFs to occur before the work begins. The programs of C1 are described below:

Third Party (ISN[16] Qualification) – SCE utilizes ISN as an independent third-party consultant to evaluate our Safety Tier 1 HR and Safety Tier 1 contractor workforce, in terms of their historical safety performance and programs as related to the type of work they do for SCE or on SCE property. This information provides SCE with a benchmark against North American Industry Classification

[16] ISNetworld (ISN): SCE's third-party administrator (TPA) which conducts safety qualification of all Safety Tier 1 contractors, collects monthly safety data submissions by contractors, and maintains a repository for contractor safety documentation.

System (NAICS) codes. It also establishes a framework for the contractor's overall safety performance as it relates to industry averages. SCE has established benchmarks for OSHA, DART, and SIF rates and counts. This helps give SCE visibility regarding objective criteria that reflect on a contractor's ability to work safely. SCE has established a scoring metric based on the contractor's safety processes, documentation, and performance. ISNetworld continuously applies this scoring metric to each contractor, resulting in a letter grade. A contractor must be able to achieve a qualifying grade (A, B, or C with a Conditional Contractor Plan) to perform Safety Tier 1 HR or Safety Tier 1 work on SCE property.

Conditional Contractor Plans – Contractors that receive an ISN C grade are required to submit a plan that, to SCE's satisfaction, demonstrates the contractor is taking adequate steps to mitigate the incidents and contributing factors that had caused them to receive a C grade. The plan is reviewed by SCE SMEs and OU (Operating Units) representatives to make sure that the appropriate mitigations and efforts are in place. The plan requires final approval from OU and Safety Directors. SCE then monitors the plan by requiring the contractor to submit quarterly reports that describe their performance relative to their commitments.

Request for Proposal (RFP) Development – SCE develops RFPs to solicit contract support to fulfill operational needs. For Safety Tier 1 HR and Safety Tier 1 work, safety provisions are incorporated into RFPs, requiring that contractors take the following steps: 1) have an active ISN account and receive a qualifying grade; 2) review and execute SCEs Hazard Assessment and Safety Plans (HASP)[17] and Contractor Handbook Orientation Checklist (CHOC)[18] as part of their submittal; 3) provide a safety organizational chart and individual resumes that identify the span of control and the

[17] Hazard Assessment and Safety Plan (HASP): A document for Edison Representatives to collaborate with contractor leadership to document hazard awareness and mitigation plans before any Safety Tier 1 work begins. The assessment identifies potential health and safety issues and hazard mitigation associated with the project/work scope, and the project/work locations known to SCE at the time the RFP is issued, and the Contractor's plans to mitigate those hazards.

[18] CHOC is a document that is used during the orientation process for the SCE Representative and the contractor to review the safety requirements in the HS Handbook for contractors and to document the contractor's understanding and acknowledgement of these requirements.

employee safety qualifications that will be dedicated to the scope of work; and 4) describe their Safety Observation Program and demonstrate to SCE that the program can document observations, provide trending data, and possesses the capability to support corrective actions.

SCE evaluates contractor submittals to ensure the contractors properly understand the scope and complexity of the work under consideration, and that the contractors have an effective plan that meets SCE's safety expectations. The results are ranked, scored and taken into consideration along with other important aspects of the contractor's bid (such as cost, quality control measures, and schedule).

Contractor Orientation (CHOC HASP) – Prior to the start of work, SCE requires an orientation meeting between the Contractor Representatives, SCE Representatives, and Contract Management agents to review the HASP and CHOC. Review of the CHOC requires a page-turn and review of SCE's Handbook for Contractors to confirm that all involved parties know and understand SCE's expectations for operating safely. Details such as employee orientation, qualification of employees, employee and subcontractor oversight, safety professional requirements, incident management requirements, and expectations for stop work responsibility are discussed in detail. Review of the HASP requires discussion centering around existing and known hazards associated with the work, SCE's expectations for addressing Critical Observable Actions (COAs),[19] and a thorough examination of the contractor's mitigation plan.

Badging and Training Qualification – SCE has implemented the badging and training qualification program with our Vegetation Management organization. This program mandates that contractors validate that they have provided proper orientation to their workers and confirm that their employees are qualified to perform specific high-risk tasks. For example, a contractor must document the date they qualified a worker to operate a chainsaw, before that worker is allowed to perform chainsaw operations. Other examples of critical tasks include working near high-voltage lines and equipment, operating equipment, climbing trees, and conducting traffic control operations.

[19] COAs are discussed below.

SCE monitors the contractors' training records, providing real-time feedback to contractors to support and ensure the contractor has qualified their employees to perform critical tasks. Beginning in 2022, SCE is expanding the program to include more of our higher-risk contractor workforce, with a focus on confirming that the contractor has provided essential orientation and familiarization with respect to the contractor's own programs, SCE's orientation requirements, leader safety culture training, and COAs.

1. Drivers Impacted

C1 will impact drivers D1- People and D2 – Please refer to the discussion below.

D1 People: The frequency of this driver group will be reduced with a tracking system that enables contractors to report their progress for the training and orientation of contractor workers. Contractors are also required to provide monthly updates on key safety metrics. This includes the number of hours worked, number of crews, number and top findings of safety observations, and ratio of safety observers to workers.

D2 – Process: This frequency of this driver group will be reduced by ensuring SCE identifies known hazards to contractors during the RFP process, and confirmed by contractor orientation checklists before work begins. Contractors must provide sufficient mitigations for the identified hazards. As discussed earlier in this chapter, contractors that have had prior safety performance issues will be required to demonstrate their plan to improve their performance with a written Conditional Contractor plan that must be approved by SCE before any work begins. Contractors are required to provide documentation and mitigation measures to manage risks and confirm program expectations are met (such as the appropriate number of safety observers and development of safety culture programs).

D3 Equipment – Control C1 focuses on pre-qualification of contractors and is not expected to impact incidents driven by equipment failure.

2. Outcomes and Consequences Impacted

This control does not impact any outcomes or consequences.

B. C2 – Oversight, Performance Management and Culture Development

The programs identified in C2 Oversight, Performance Management and Culture Development, are in place to minimize SIFs while work is occurring. The components of C2 are described below.

SCE Field Observations are conducted on our contractor workforce to confirm that SCE can observe the right behaviors and performance that align with our values. SCE looks for opportunities to recognize good performance and to identify opportunities for improvement, whereby we have discussions with the crews and leadership to ensure safe performance. SCE tracks and observes trends on the number of observations conducted, whether they meet expectations, exceed expectations, or have opportunities for improvement. SCE maintains data and performance metrics to help us assess if we are trending in the right direction.

Third-party field observations bear certain similarities to SCE field observations. SCE contracts with third-party safety consultants to augment the observations carried out by SCE's workforce. We make appropriate use of these consultants particularly during times of increased workload, such as wildfire mitigation and capital project work.

COA implementation - For select Safety Tier 1 HR Contractors, SCE and our contractors partner together to identify COAs in an effort to reduce serious injuries and fatalities. COAs are defined as those observable mitigation measures that protect against primary hazards that can lead to serious injuries and fatalities. COAs have been identified for the following work scopes:

1. Vegetation Management – Compliance Tree Trimming
2. Overhead Distribution
3. Substation Construction
4. Transmission Bulk Power
5. Underground Civil
6. Distribution / Sub-Transmission Air Operations

CSQAR (Contractor Safety Quality Assurance Review) - Selected contractors are required to work with SCE to perform CSQARs. These are detailed onsite assessments concerning how a Contractor:

- Implements the SCE HS Handbook for Contractors
- Manages their program, and checks and confirms field implementation
- Leverages its leadership team to drive safety culture

The CSQAR process includes a desktop review, field observations, and SCE/contractor leadership engagement. Any observed unmitigated hazards are addressed immediately and escalated as necessary. Safety concerns or issues identified are documented and communicated to the contractor and the SCE representative, and an action plan for compliance and mitigation is established by the contractor.

Lessons learned and best practices may be shared broadly to encourage continuous growth and development in the industry.

When we select the contractors that will undergo review, we give priority to contractors conducting higher-risk work, having longer worker shifts and schedules, or experiencing recent safety performance issues (e.g., conditional contractors).

Scorecards - SCE Supply Management executes and manages contractor score cards to assess safety, quality, and general performance. From a safety perspective, the score cards are used to drive meaningful discussion on a contractor's monthly performance, and drive alignment with key performance indicators. These indicators include EEI SIF counts and rates, number of documented safety observations, and safety support span of control, and are aligned with SCE's HS Handbook for Contractors and overall SCE safety objectives. Performance is managed on a month-to-month basis. Action plans are developed by the contractor as needed to maintain alignment on performance.

Core Performance Dashboards and Monthly Reporting - SCE monitors and tracks leading and lagging indicators. We publish them in monthly reports to inform decisions and drive areas of focus. The dashboards contain information such as observation counts and findings, and injury and incident trends which show broad SCE contractor performance as well as items that provide focus on safety performance for contractors performing work for specific OUs.

Contractor Control Stages - SCE has a system to progressively manage undesired behavior or performance. Steps can include corrective action plans and control stages. Control stages can include work restrictions, crew count restrictions, reduction in work, and ultimately termination, if the conditions identified in SCE's formal notification are not met.

Safety Leader Culture Training - All Safety Tier 1 HR contractors who have worked or plan to work at least 25,000 hours/year for SCE must implement a Leader Safety Culture Training course. This course must be applied to all of the contractor's leaders (including management, foremen, and supervisors) that oversee contractor employees who are conducting Safety Tier 1 work for SCE. New leaders are required to be trained within six months of being placed in a leader role. Topics that can be included in the training include:

a. The role of a leader in building and sustaining a strong safety culture;
    i. Leveraging leader influence
    ii. Internal leadership frame and impact on team dynamics
b. Personal safety ownership — Understand personal motivation for investing in safe work practices (what are we staying safe for rather than from), how to develop an attitude and mindset to take control of personal safety, and the importance of connecting personal safety values with the personal "why" to foster leadership;
c. Techniques to assess and manage risk — establish a connection between personal behavior and existing tools/work practices (e.g., Human Performance);
d. Techniques to improve communication with peers and colleagues;
e. The importance of speaking up;
f. Understanding the sphere of influence and control;
g. Learning over blame — How to evaluate incidents with a focus on learning (not blame) and how to implement programmatic and systematic improvements to reduce the risk of the same event recurring; and
h. Leadership tools to align attitudes, behaviors, and results, including safety observations, recognition, modeling, and coaching.

Contractor Communications - SCE sends out weekly and ad-hoc communications to raise awareness around incidents and lessons learned, and to communicate manufacturer recalls, leader messaging, general safety messages, etc. The expected outcome of this messaging is to expand contractor knowledge of trends and recent events, and to provide contractors with insights to help prevent similar incidents.

Contractor Safety Forums - SCE Operating Units that are actively working with Safety Tier 1 Contractors must ensure that Contractor Safety Forums are held at least once per year. These forums are attended by SCE personnel and active SCE Tier 1 Contractors, and documentation (e.g., attendance sheets, agendas) of each forum is required to be maintained. The purpose of the forums is to discuss relevant safety issues and maintain open lines of communication to ensure mutually safe work efforts. The SCE Operating Units (OUs) must organize the forums, with OU Directors or Principal Managers facilitating the discussion. At a minimum, the forums must cover the following topics:

a. Best practices and industry challenges;
b. Safety expectations and requirements for the contractor, including reinforcing roles and responsibilities pertaining to SCE standards; and
c. Lessons learned from relevant incidents.

The Contractor Safety Advocate - is a designated member from each OU responsible for sharing and communicating contractor safety information to their management and OUs. CSA Monthly meetings provide Contractor Safety Advocates (CSAs) with a deeper understanding of the safety requirements listed in the HS Handbook and Standard, as well as any ongoing safety changes. CSAs also provide best practices and oversight tools, to help foster safety ownership and engagement.

California Utility Forum is a bi-monthly meeting that SCE facilitates with other California utilities (including PG&E, SDG&E, SoCalGas, LADWP and SMUD). This serves as a benchmarking program. It allows us to share contractor safety-related experiences, program updates, and best practices.

1. Drivers Impacted

C2 will impact all drivers as described below.

D1 People – C2 will reduce the frequency of this driver group by increasing SCE field observations. The Proposed Plan will carefully and steadily replace previous third-party observers with in-house resources. The third-party observer resources were only working in high fire risk areas.

The Proposed Plan will increasingly rely on in-house resources, so that we can expand the geographic span of observations to cover all SCE areas, and not restrict this safety activity to high fire risk areas only.

Observers will stop work if the observer identifies an unsafe situation or behavior. This prevents the immediate hazard from resulting in a safety incident and provides valuable coaching and teaching opportunities. The CSQAR process and contractor scorecards give selected contractors feedback on their most recent safety performance. The process and scorecards also provide valuable information that assists SCE in selecting contractors for future work. The work product also serves as a basis for taking control actions in stages, up to and including terminating the work relationship if a contractor is not performing safely. Through the combined efforts of contractor safety forums, SCE contractor safety advocates, and SCE safety communications, contractors are consistently made aware of recent safety incident trends, and items such as extreme weather notices (which can affect wildfire conditions).

D2 Process – C2 will reduce the frequency of this driver group with in-field verification of contractor safety performance and orientation requirements, as well as verification of traffic management operations, contractor crew tailboards, and field communications. Critical observable actions focus on crucial steps that must be in place to keep workers safe and to support managing unfamiliar conditions and communications, and addressing traffic management gaps.

Additionally, elements of evolving safety culture are captured in observations, and feedback is collected during observations. This can inform decisions on overall contract management and help support continuous improvement and ongoing collaboration in eliminating serious injuries and fatalities. Contractor communications are developed each week, in order to share leading and lagging indicator information such as trending observation opportunities and incidents. The goal is to enhance learning opportunities so that risk drivers such as traffic control or unfamiliar conditions are specifically targeted for being addressed.

D3 Equipment – C3 will reduce the frequency of this driver group by maintaining contractor awareness of recent incidents involving equipment, as well as equipment manufacturer recalls. The efforts here span multiple SCE communication streams, including Wired for Safety, Weekly Incident Communications, and Safety Alerts.

2. Outcomes and Consequences Impacted

This control does not impact any outcomes or consequences.

C. C3 – Incident Management and Learning

The programs identified in C3 Incident Management and Learning, are designed to draw learning from incidents that have occurred and develop and communicate appropriate mitigation steps to minimize future reoccurrences. The components of C3 Incident Management and Learning are described below:

Incident Evaluations - SCE requires that contractors notify the designated Edison Representative regarding all safety incidents that occur while the contractor works for SCE.
(This includes relatively low-level incidents such as sprains and strains.) The variety of Safety Incidents that must be reported encompasses the following: First-Aid incidents, injuries above First Aid status, Close Calls, safety violations, vehicle accidents, property damage, equipment failure, crew-caused circuit interruptions (CCCI), unplanned outages, primary/secondary electrical flashes, switching incidents, wiring/conductor incidents, grounding incidents, hazardous material releases, customer complaint/negative contacts, and fires.

For High Energy or Fatality (HSIF), or Low Energy Serious Injury incidents (LSIF) including fatalities, contractors must conduct a thorough cause evaluation to identify both direct and organizational causes that led to the incident. The contractor must identify robust corrective actions. Prime contractors are responsible for ensuring that that their subcontractors complete cause evaluations.

Contractor Management Review Committees - Edison Safety convenes a Contractor Management Review Committee (MRC) to review the cause evaluation reports associated with Actual LT/LA incidents, select Potential LT/LA incidents, and HSIF, LSIF, and PSIF incidents. The review aims to make sure that the cause evaluations adequately identify, analyze, and resolve physical and behavioral conditions that led to the incident. These include organizational and programmatic issues that caused or contributed to an incident. The MRC also reviews associated corrective actions taken to improve the Contractor's safety and reliability performance. The MRC can include employees from Edison Safety, Supply Management, and the specific SCE Operating Unit that works with the contractor. A contractor representative may be requested to attend.

Contractors must address all feedback from the Contractor MRC, and prime contractors are responsible for ensuring their subcontractors address all contractor MRC feedback for subcontractor incidents. The SCE representative or delegate is responsible for engaging the contractor, sharing information related to the specific incidents under review, and ensuring contractor action items are completed.

Common Cause Evaluations - SCE is beginning to develop Common Cause Evaluations (CCE) for contractor incident. CCEs are designed to collectively evaluate a set of data or occurrences (i.e., patterns or commonalities within a series of incidents) for commonly shared issues that typically indicate an adverse trend or failure of a program or process. Outcomes from CCEs include an operating experience communication. This communication describes the types of incidents analyzed, learnings, and actions items to prevent future occurrences. This is a program implemented for SCE employees and we are starting to implement it for specific types of contractor incidents.

Corrective Action Plan Management - SCE is developing systems and resources to assemble corrective commitments made by contractors that are developed in response to incidents, conditional contractor plans, and CSQARs. The intended outcome of corrective action tracking is to increase awareness of contractors' commitments, and to support accountability and longevity of effective implementation. SCE will also be able to broadly communicate final lessons learned and preventive measures from incidents.

Incident Review Teams - Following a Serious Injury or Fatality — e.g., Actual Life Threatening/Life Altering (LT/LA) or High Energy or Fatality (HSIF) or Low Energy Serious Injury or Fatality Incident (LSIF) — the OU must gather an Incident Review Team with leadership from the OU, Supply Management, and Edison Safety to initially undertake the following actions:

a. Review the incident;

b. Review the contractor's response to the incident (e.g., cause evaluation, corrective actions, immediate actions taken, etc.) and the contractor's general safety performance; and
c. Determine appropriate actions, including immediately assigning Conditional Contractor Status, assigning a Control Stage, conducting a CSQAR, Stand Down, or potentially off-boarding the contractor.

After the initial IRT meeting, the team shall review the overall response to the incident and:

a. Verify that the cause evaluation conducted through the 60-day report thoroughly evaluates potential contributors to the incident;
b. Verify that the cause evaluation identifies the appropriate causes;
c. Verify that the proposed corrective actions will address the identified causes; and
d. Verify that the contractor has an oversight plan in place to confirm the effectiveness of the corrective actions.

The OU must hold initial and follow-up meetings with SCE OU leadership, Supply Management, and Edison Safety leadership to review the incident and associated incident cause evaluations. This team must also determine next steps/actions, including:

a. Initial Incident Review Call: Within 24 hours of a contractor fatality or two business days of incident classified as an Actual LT/LA incident, HSIF, or LSIF (and selected Potential LT/LA incidents or selected PSIF), the OU must hold an Initial Incident Review call;
b. 5-Day Follow-up Report Call: Within five business days of receipt of the 5-day follow-up report, the OU must hold a call to review the 5-day report;
c. 60-Day Follow-up Report Call: Within five business days of receipt of the 60-day follow-up report, the OU must hold a call to review the 60-day report; and
d. Incident Status Check: At approximately six months from the incident, the OU must reconvene the Incident Review Team to assess the status of the contractor and determine if any additional actions are needed to ensure the contractor has taken adequate steps to improve their safety performance

1. **Drivers Impacted**

C3 will impact all drivers as described below.

D1 People – C3 seeks to identify gaps (post-incident) such as hazard identification failure, stop work responsibility failures, human performance failure, and other incident causes. C3 will reduce this driver group by involving contractors in the SCE MRC process for reviewing and approving 60-day reports following actual or potential serious incidents. This will provide contractors with the benefit of SCE's cause analysis expertise, and help contractors identify causes and put in place the appropriate corrective actions.

D2 Process- C3 will reduce the frequency of this driver group by involving contractors in the review of their incidents, reviewing and approving the contractor's corrective action plans and sharing learnings from other contractor incidents. Performing common cause evaluations will provide an additional level of process assessment, thereby supporting contractors in identifying gaps in their processes and enabling them to develop appropriate mitigation solutions.

D3 Equipment – C3 will reduce the frequency of this driver group by supporting contractors in evaluating both actual and potentially serious incidents involving equipment failure, and sharing those learnings with other contractors.

2. **Outcomes and Consequences Impacted**

This control does not impact any outcomes or consequences.

IV.

MITIGATIONS

In the normal course of business, and as part of developing this RAMP report, SCE continually identifies more effective ways to mitigate this risk. These approaches are modifications or enhancements to the controls listed above in Section III, and we did not feel that these should be considered separate mitigations. A more detailed discussion on the expansion of the controls is in Section VI.

V.

FOUNDATIONAL ACTIVITIES

SCE is in the process of implementing an incident management system (IMS) that will support Contractor and Employee safety controls and mitigations.

A. F1 - Incident Management System (IMS)

1. Overview

An incident management system (IMS) is a software solution that supports the entire incident management lifecycle. It allows all incidents to be reported, evaluations to be managed, and corrective action plans to be monitored. The application offers comprehensive web and mobile data collection features, and advanced reporting and data analysis capabilities. Incidents can be recorded with multiple impacts (human, environment, media, etc.) to reflect a wide range of incident categories and subsequent management by different teams. Incident forms as well as their workflows and notifications can all be configured to fit business processes at a local and global level.

An IMS includes the following capabilities:

- Employee and contractor incident management
- Corrective and preventive actions
- Inspection management
- Observations
- Mobility

2. Rationale for Inclusion as Foundational

SCE believes that an IMS is a foundational tool that supports the programs detailed within the Safety Management System (SMS).[20] Data collected and reported by the IMS will aid in understanding where the SMS is performing well and where improvements can be made. The IMS system will provide better tracking and approval mechanisms for documenting and analyzing contractor safety incidents and close calls. IMS will also supports SCE's cause evaluation and corrective action

[20] For more detail on the SMS, please see Chapter 9 - Employee Safety.

process, facility inspections related to hazard identification, and safety observations. The IMS is a critical tool in culture monitoring, as increased reporting and robust trend code capabilities will allow development of "Culture Trend Codes." The use of these codes allows for a "real-time" view of culture change as incidents are reported and hazards mitigated.

3. RSE Cost Allocation Treatment

Currently SCE plans to select a vendor in 2022. This will be followed by designing and building the system. In 2023, SCE plans to roll out and stabilize the IMS. In 2023 and beyond, there may be annual licensing fees and potential system enhancements; however, those costs will not be known until SCE selects the final vendor or until future system enhancements are identified.

SCE estimates that the annual spend for IMS in 2022 and 2023 is approximately $2.4 million dollars. Since these costs are incurred prior to SCE's next rate case cycle (2025 – 2028), these can be considered sunk costs and are not allocated to any controls and mitigations for purposes of RSE calculations. To the extent that SCE is able to identify any of the annual licensing or potential future system enhancements, SCE plans to include those items in RSE calculations for any controls or mitigations that they support in the Test Year 2025 GRC.

VI.

PROPOSED PLAN

SCE has developed a Proposed Plan to mitigate this risk, as shown in Table VI-10 below. The pre-and post-risk scores by tranche are displayed in Table VI-11.

Table VI-10
Proposed Plan (Total Costs in Millions and 2025 Risk Spend Efficiencies)[21]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Pre-Qualification and On-Boarding	$0.43	-	4,017
C1 - T2	Pre-Qualification and On-Boarding	$0.43	-	302
C2 - T1	Oversight, Performance Management and Culture Development	$2.21	-	1,651
C2 - T2	Oversight, Performance Management and Culture Development	$0.95	-	351
C3 - T1	Incident Management and Learning	$0.35	-	9,218
C3 - T2	Incident Management and Learning	$0.15	-	1,918
Total		**$4.54**	**$0.00**	**-**

Table VI-11
Pre- and Post- LoRE, CoRE and Risk Scores[22]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
Contractor Safety	**LoRE**	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
	13.05	0.17	2.17	10.38	0.17	1.72
T1 - Tier 1 Higher Risk	11.61	0.17	1.99	9.22	0.17	1.58
T2 - Tier 1	1.45	0.13	0.18	1.16	0.13	0.14

A. Overview

The Proposed Plan represents continuation of all existing controls in 2025 – 2028, as well as other program enhancements to maximize mitigation efforts in three critical areas: Pre-Qualification, Performance, and Learning.

21 Please refer to Contractor Safety RAMP Risk Model (excel file) and WP. Ch. 10 – Contractor Safety RAMP Financials.

22 Please refer to Contractor Safety RAMP Risk Model (excel file).

- **Pre-Qualification** programs will be enhanced as follows:
    - **RFP Development** – focus on more projects where rapid deployment introduces higher safety risks.
    - **Orientation** - provide more comprehensive contractor orientation support to ensure orientations are planned and performed appropriately, reducing downstream safety risks.
    - **Training Qualification** – this program currently only covers the Vegetation Management category of work. Expand to include other high-risk work types, such as Distribution, Transmission and Underground Civil.
- **Performance** programs will be enhanced as follows:
    - **Field Observations -** enhance span of controls allowing SCE field observers to be more effective in their roles and reduce the need for third-party support.[23]
    - **COAs –** Critical Observable Actions have been developed for five key types of work; Vegetation Management, Underground Civil, Overhead Distribution, Bulk Power Transmission, and Air Operations. Expand program to include additional work types, such as Crane Operations and Traffic Management. We also plan to refresh COAs that were developed several years ago, including Vegetation Management.
    - **CSQARs –** Enhance this program to review more contractors in the Safety Tier 1 HR category on an annual basis.
- **Learning** programs will be enhanced as follows:
    - **MRCs** - This program will be expanded to support the communication of final contractor cause evaluations and corrective actions to all contractors in SCE's workforce and maximize the learning from those incidents.
    - **CCEs -** common cause evaluations are currently shared for selected SCE employee incidents. This program will enhance CCEs to include contractor incidents.

[23] The use of third-party oversight resources initially occurred for wildfire mitigation-related activities in 2019.

- **Corrective Action Plans** – this program will build systems to buttress the sustainability of corrective actions by making corrective action data readily available for field validation.

B. Execution Feasibility

SCE believes that the Proposed Plan is feasible and will continue existing efforts while building on those existing controls. The enhancements will enable key SIF elimination programs to have a greater impact on our contractors by focusing on validating compliance and strengthening our ability to hold responsible parties accountable. In addition, replacing third-party observation consultants with new hire in-house resources will reduce costs and provide a greater depth and span of control. We will then be able to include all SCE work sites for this capability, and not restrict it to wildfire mitigation activities in high fire risk areas.

C. Affordability

The combination of existing and enhanced activities in the Proposed Plan represents a puts-and-takes balance that should reduce safety risks at prudent cost when fully implemented in 2025.

D. Other Considerations

In developing the Proposed Plan, SCE looked at areas where program enhancements could have the largest impact on reducing SIF, and for these specific key controls, what could be done to achieve the maximum possible impact on SIF reduction. As a result of this analysis, SCE plans to hire additional in-house resources to expand on the key initiatives already in place, to achieve the maximum potential of key objectives, as evaluated by SCE SMEs.

VII.

ALTERNATIVE PLANS

A. Alternative Plan #1

SCE developed Alternative Plan #1 as shown in Table VII-12 below. The pre- and post-risk scores by tranche are displayed in Table VII-13.

Table VII-12
Alternative Plan #1 (Total Costs in Millions and 2025 Risk Spend Efficiencies)[24]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Pre-Qualification and On-Boarding	$0.26	-	2,305
C1 - T2	Pre-Qualification and On-Boarding	$0.26	-	173
C2 - T1	Oversight, Performance Management and Culture Development	$2.21	-	1,767
C2 - T2	Oversight, Performance Management and Culture Development	$0.95	-	363
C3 - T1	Incident Management and Learning	$0.23	-	3,846
C3 - T2	Incident Management and Learning	$0.10	-	817
Total		**$4.01**	**$0.00**	**-**

Table VII-13
Pre- and Post- LoRE, CoRE and Risk Score for Alternative Plan #1[25]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
Contractor Safety	**LoRE**	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
	14.10	0.17	2.34	12.56	0.17	2.09
T1 - Tier 1 Higher Risk	12.54	0.17	2.15	11.17	0.17	1.91
T2 - Tier 1	1.56	0.13	0.19	1.39	0.13	0.17

Alternative Plan #1 represents continuation of all existing controls in 2025 – 2028 as well as enhancements to maximize mitigation efforts in C2 – Oversight, Performance Management and Culture Development Control.

24 Please refer to Contractor Safety RAMP Risk Model (excel file) and WP. Ch. 10 – Contractor Safety RAMP Financials.

25 Please refer to Contractor Safety RAMP Risk Model (excel file).

- **Performance** programs will be enhanced as follows:
  - **COAs –** Critical Observable Actions have been developed for five key work types; Vegetation Management, Underground Civil, Overhead Distribution, Bulk Power Transmission, and Air Operations. Expand program to include additional work types, such as Crane Operations and Traffic Management. We also plan to refresh COAs that were developed several years ago, including Vegetation Management.
  - **CSQARs –** Enhance this program to review more contractors in the Safety Tier 1 HR category on an annual basis.

1. Execution Feasibility

SCE believes that Alternative Plan #1 is feasible, since this plan requires less labor compared to the Proposed Plan. SCE will continue the existing efforts and build on only one control, rather than build on the three controls described in the Proposed Plan. SCE already has the previously-defined processes and procedures in place to implement the additional performance mitigations.

2. Affordability

Although Alternative Plan #1 provides additional savings over the Proposed Plan, we ultimately did not select this plan because SCE respectfully believes that, looking at all relevant factors, Alternative Plan #1 does not provide a reasonable level of funding and activities to adequately address Contractor safety risk.

3. Other Considerations

SCE did not identify any other considerations for Alternative Plan #1.

B. Alternative Plan #2

SCE developed Alternative Plan #2 as shown in Table VII-14 below. The pre- and post- risk scores by Tranche are displayed in Table VII-15.

Table VII-14
Alternative Plan #2 (Total Costs in Millions and 2025 Risk Spend Efficiencies)[26]

ID / Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Pre-Qualification and On-Boarding	$0.26	-	4,867
C1 - T2	Pre-Qualification and On-Boarding	$0.26	-	366
C2 - T1	Oversight, Performance Management and Culture Development	$1.12	-	697
C2 - T2	Oversight, Performance Management and Culture Development	$0.48	-	147
C3 - T1	Incident Management and Learning	$0.23	-	3,628
C3 - T2	Incident Management and Learning	$0.10	-	766
Total		**$2.45**	**$0.00**	**-**

Table VII-15
Pre- and Post- LoRE, CoRE and Risk Score for Alternative Plan #2[27]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
Contractor Safety	**LoRE**	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
	14.87	0.16	2.35	14.37	0.15	2.11
T1 - Tier 1 Higher Risk	13.23	0.16	2.15	12.78	0.15	1.91
T2 - Tier 1	1.64	0.13	0.21	1.59	0.13	0.20

[26] Please refer to Contractor Safety RAMP Risk Model (excel file) and WP. Ch. 10 – Contractor Safety RAMP Financials.

[27] Please refer to Contractor Safety RAMP Risk Model (excel file).

1. Overview

Alternative Plan #2 represents continuation of all existing controls without enhancing any program efforts in critical Control areas. Alternative Plan #2 does not include additional SCE staff to replace existing third-party observation consultants.

2. Execution Feasibility

SCE believes that executing Alternative Plan #2 is feasible, since the Plan does not require any additional labor. The third-party contract for observing wildfire mitigation activities is scheduled to expire in 2024. It would not be renewed.

3. Affordability

Alternate Plan #2 costs approximately $2 million less per year than the Proposed Plan. Although Alternative Plan #2 provides savings over the Proposed Plan, at best it might maintain the status quo for risk reduction. In our view, this would not adequately address Contractor safety risk of SIFs. The Proposed Plan, at reasonable cost, would offer enhancements to our safety risk mitigation efforts and capabilities. Also, by replacing third-party observation consultants with in-house resources, we expect to see some cost avoidances.

4. Other Considerations

SCE did not identify any other considerations for Alternative Plan #2.

VIII.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

Below SCE describes several lessons learned from both our previous RAMP and from feedback on other IOU RAMP reports.

1. SCE Further Tranched Contractor Safety Based on Risk Exposure

When the Commission's Safety Policy Division (SPD) provided its Regulatory Review of Sempra's 2021 RAMP report, SPD noted with concern that Sempra only had one tranche for all of contractor safety.[28] In other words, Sempra had one risk tranche for all contractors.

As discussed in Section II.F above, SCE has followed the SPD guidance. Rather than having one single risk tranche for all contractors, SCE tranched out our contractor workforce based on the risk profile of the work they perform. Accordingly, we have two risk tranches for contractors.

SCE will continue to evaluate which contractor job types fall into Tier 1 or Tier 1 HR. For example: following a contractor fatality in April 2020 that involved the unloading of material from a flatbed truck, SCE reclassified all work involving the loading/unloading of trucks and trailers using power equipment. SCE reclassified this work as Safety Tier 1, rather than the previous Tier 2 classification.

2. The Inclusion of Potential Serious Injuries and Fatalities into the MAVF Framework Proved Challenging

SCE is committed to reducing safety incidents throughout its workplaces. This includes actual SIFs, PSIFs, and less serious injuries. As described above, SCE has multiple controls and mitigations to help provide a safe workplace while preventing SIFs in accordance with applicable laws, regulations, and best business practices. In order to capture the safety risk to our employees and contractors, SCE attempted to integrate the PSIF into the MAVF for this RAMP. However, SCE experienced two major challenges trying to incorporate PSIF incidents into the MAVF as described below.

First, SCE did not find a useful and rigorous methodology to incorporate PSIF incidents into the consequences of the risk bowtie. While SCE does have the same level of detail on potential incidents (driver, sub-driver, tranche, etc.) as actual incidents for certain bow-tie elements (driver, sub-driver, tranche), it was unclear what consequence scoring those incidents should be given in the MAVF.

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[28] *See* Safety Policy Division Staff Evaluation Report on SDG&E's and SoCalGas' Risk Assessment and Mitigation Phase (RAMP) Application Reports, p. 102.

Second, the inclusion of these PSIF incidents may be inconsistent with how other risks are evaluated. For instance, it is near-impossible for SCE to include potential serious injuries or fatalities to the public if we are unaware that they occurred. To take a practical example, if a member of the public almost gets electrocuted while breaking into our facility to steal copper wire, but no electrocution event or incident actually occurs, SCE may not even have awareness of the "almost" aspect of the situation. This is a limitation that would presumably apply to other utilities as well who may be in a similar situation.

Moreover, inclusion of the PSIFs at this time may lead to intervenors or other stakeholders asserting that the scores are "inflated" because potential incidents rather than actual ones are driving the risk score up. Parties may strenuously disagree as to what constitutes a possible incident and what does not. In other words, parties may have differing views on what was enough of a "close call" that inclusion of the item (and corresponding increase in the risk score) would be warranted. Thus, if SCE for example included PSIFs for employee and contractor incidents, it may lead to stakeholders feeling that the risk scoring for the Employee and Contractor Safety risks appears to be overstated compared to other RAMP risks.

SCE will continue to investigate methodologies for appropriately incorporating PSIFs into the MAVF. If further exploration leads to a workable and accurate approach for weighting a potential SIF as compared to an actual SIF, SCE would seek to include that additional layering in our Test Year 2025 GRC Application. SCE is also open to discussions with parties in the Risk OIR proceeding concerning appropriate on methodologies or approaches for specifically incorporating PSIFs into the MAVF framework. SCE takes every safety incident seriously, whether it is relatively minor (such as a slip or fall resulting in a DART-level incident) or serious (such as a switching incident with a flash, resulting in 3rd degree burns suffered). Further, SCE treats PSIF incidents in the same manner as actual SIF incidents.

In many cases, a PSIF could have resulted in an actual SIF to a contractor. Put another way, while the consequence of actual SIF and PSIF incidents may have been different, the circumstances are often very similar, such that an actual SIF could have occurred. SCE requires the same level of reporting (including 5- and 60-day follow up reports and MRC review of cause evaluations) for all serious incidents, whether an actual injury occurred or not. Cause evaluations are performed on actual and potential SIFs to identify and implement corrective actions to reduce the risk of future, similar incidents. In its efforts to address risk drivers of contractor safety incidents, SCE treats PSIF incidents with equal attention and similar resources as actual SIF incidents.

Finally, an important consideration here is that the exclusion of PSIFs in the MAVF may mean that the full benefits of the proposed controls and mitigations may be understated. The benefits that a control or mitigation may have in reducing PSIFs are not visible.

3. Determining Mitigation Effectiveness Values Still Proves Challenging

SCE's overall contractor safety program consists of an assembly of mitigation programs intended to target critical areas across the entire life cycle of a work contract. Results of individual mitigation measures are not easily measurable on their own, as they are symbiotic and are reliant on each other to be successful. Leading and lagging indicators serve as the basis for evaluating and assessing contractor performance. The relatively small number of SIF incidents per year (13 in 2021) makes statistical trending difficult in the short term. However, we believe the combined program mitigations should result in a demonstrable reduction in contractor SIFs over a period of several years.

B. Data Collection and Availability

SCE continues to improve upon the collection of information related to contractor safety incidents. Since the 2018 RAMP, SCE has improved the trending of safety-related incident causes, activities, human performance, SIF Exposure, energy sources and controls for safety data analysis. All SCE contractors are required to report all safety incidents to SCE within one business day, using SCE's reporting form. These incident reports are reviewed for completeness by the SCE representative responsible for that contractor's scope of work. Edison Safety then establishes a s severity rating for each incident, using the EEI SCL model. Despite our efforts since the 2018 RAMP, some of the data analysis performed for this chapter still required manually transposing and interpreting of data across several datasets. SCE continues to enhance our predictive modeling and cause evaluation efforts, along with data collection systems, to better target our safety analyses and risk mitigation approaches.

C. Performance Metrics

SCE tracks a significant amount of data related to contractor safety incidents. Table VIII-16 below summarizes some key performance metrics; however, this is not an exhaustive list. The table also indicates whether any of these metrics are included in SCE's annual Safety Performance Metrics (SPM) report[29] and if there is any relationship to the RAMP bowtie in Figure II-2 and risk analysis. SCE attempted to include a combination of leading and lagging indicators.

Table VIII-16
List of Contractor Safety Performance Metrics

Metric	Leading / Lagging Indicator	Included in SPM Report	Metric Directly Included in Risk Bowtie	Description
Contractor SIFs - Actual (Count and Rate)	Lagging	Yes	Yes	Count and Rate of incidents that resulted in a serious injury or fatality to an SCE contractor as defined by the Edison Electric Institute (EEI) SIF criteria. This includes HSIF and LSIF incidents, per the EEI Safety Classification and Learning (SCL) Model. This directly informs the triggering event frequency of the risk bowtie.
Contractor Hours worked	-	Indirectly	Yes	The number of Tier 1 contractor hours worked informs the risk exposure and is used in calculating SIF rates.
Contractor Potential SIFs - Actual (Count and Rate)	Leading / Lagging	Yes	No	Count and Rate of incidents that resulted in a potential serious injury or fatality to an SCE contractor as defined by the EEI Safety Classification and Learning (SCL) Model. Currently these incidents are not included in the bowtie.
Contractor DART Rate / Count	Leading / Lagging	Yes	No	DART injuries are determined based on number of Occupational Safety and Health Administration (OSHA)-recordable injuries resulting in Days Away from work and/or Days on Restricted Duty or Job Transfer. DART rate is calculated using actual work hours and is standardized by using a factor of 200,000, which represents the average number of hours worked by 100 full-time workers in one year. This is currently not included in the risk analysis but is a good indicator of overall injuries and injury rate.
# of Safety Observations	Leading	No	No	Count and Rate of incidents that resulted in a potential serious injury or fatality to an SCE contractor as defined by the EEI Safety Classification and Learning (SCL) Model. Currently these incidents are not included in the bowtie.

29 This is based on the updated list of SPMs from D.21-11-009, Appendix. B.

IX.

ADDRESSING PARTY FEEDBACK

In reviewing SCE's 2018 RAMP report, Cal Advocates suggested that SCE evaluate and present potential consequences for actions without adverse outcomes, since events without adverse outcomes may represent near-miss events.[30] In response to Cal Advocates' recommendation, SCE had noted that we will consider this recommendation when developing our next RAMP report.[31] As discussed above in Section VIII.A.2, while SCE necessarily focused the bowtie and risk analysis on actual serious injuries and fatalities, SCE does agree that the inclusion of potential serious injuries and fatalities could be beneficial in more fully capturing the risk to our employees as well as the full benefit resulting from our controls and mitigations. We look forward to further discussion with stakeholders on what might serve as appropriate methodologies in future filings.

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[30] *See* I.18-11-016. -Comments of The Public Advocates Office on November 2018 Submission of Southern California Edison Company's Risk Assessment and Mitigation Phase, p. 4.

[31] *See* A.19-08-013, Exhibit SCE-11, Supplemental Testimony on Risk-Informed Strategy and Business Plan, p. 17.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Major Physical Security Incident

Chapter 11

Rosemead CA
May 13, 2022

Chapter 11: Physical Security

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I.

EXECUTIVE SUMMARY

A. Risk Overview

SCE's objective is to provide safe, reliable, affordable, and clean electricity to our customers. The physical safety of our workforce, customers, facilities, assets, and equipment is a critical part of this responsibility. The threat landscape that SCE and other electric utilities face is diverse – threats range from simple acts of theft and vandalism to coordinated attacks on the electric grid. The controls and mitigations proposed in this chapter address the current threats and security risks; these threats and risks can change rapidly with little notice.

The chapter evaluates the physical security of our facilities, and the risks posed to the people and assets in those facilities. For RAMP, we define physical security as follows: physical security encompasses elements and strategies directly involved in physical safeguarding, such as installing perimeter walls and fencing, lighting, cameras, video analytics, and conducting security patrols.

We build on this basic definition by adding a broader set of activities. These activities (in combination with the right processes, procedures, and training) help us deter, detect, assess, and appropriately respond to attempts to compromise SCE's facilities, equipment, or people in those facilities.

In this chapter, SCE quantifies the physical security risk and assesses how we mitigate physical security threats. SCE identified three primary threats that can compromise SCE's physical security:

1. A third party breaching the security perimeter due to security system bypass/breach, human/process failure, system failure, or trespassing by other means (e.g., tailgating, entry via open/unlocked doors/gates, etc.).

2. An insider (e.g., an SCE employee or authorized contractor) using their access or knowledge with malicious intent.

3. Physical damage to SCE assets or assaults on SCE workers without a breach of the security perimeter by an unauthorized person. This includes gunfire and other projectiles launched from outside the security perimeter or an Unmanned Aircraft System (UAS), also known as a drone.

This chapter analyzes incidents occurring within the perimeter of SCE property[1] that result in theft, vandalism, business disruption, workplace violence, sabotage, or a coordinated attack on substations.

SCE identified a number of compliance activities, controls, and new mitigations to address these risks and threats.[2]

- This chapter describes two compliance activities related to the North American Electric Reliability Corporation (NERC): NERC CIP-014 (CM1) and NERC CIP-003-V6 (CM2). We also include a third compliance activity, CM3 – Physical Security of Electrical Infrastructure, in response to CPUC Decision D.19-01-018. These three compliance activities help protect the bulk electric system (BES) and priority distribution operations from physical security incidents.

This chapter evaluates five controls:

- Protection of Grid Operations (C1): This includes activities to protect our electrical facilities and grid assets from multiple physical threats.
- Protection of Generation Capabilities (C2): This includes activities to protect our generation facilities.
- Protection of Major Business Functions (C3): This includes activities to protect our major business functions and administrative facilities.
- Asset Protection (C4): This includes employing security officers at our facilities, implementing a variety of physical security measures depending on the criticality of the facility, performing background checks, and providing security training for our workers.

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1 Examples are facilities, rights-of-way, easements, SCE property lines that extends beyond facilities, and other similar items.

2 CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter 2 – Risk Model and RSE Methodology, compliance activities are not modeled in this report. Compliance activities are addressed in Section III. C = Control. The term Control refers to an activity performed prior to or during 2022 to address the risk, and that may continue through the RAMP period. Controls are modeled in this report and are addressed in Section IV. M = Mitigation. This is an activity commencing in 2023 or later that addresses the risk. Mitigations are modeled in this report and are addressed in Section V.

- Smart Key Program – Phase 1 (C5): the first phased approach to replacing conventional lock-and-key devices with Smart Key technology. This phase focused on the replacement at critical electrical sites.

Finally, this chapter evaluates five mitigations:

- Smart Key Program – Phases 2 & 3 (M1, M2): A phased approach to replace conventional lock-and-key devices with Smart Key technology. M1 and M2 are considered mitigations because we have not begun any smart key installations on our *non-critical* electrical facilities and generation and business facilities (this is the scope of M1 and M2). However, C5 is considered a control because SCE has begun the installation of smart keys on *critical* electrical sites. As indicated above, C5 is Phase 1 of the Smart Key Program. Smart Key Phase 2 (M1) expands the installation to non-critical electrical facilities. Smart Key Phase 3 (M2) then expands the installation to the remaining generation and business function facilities.
- Enhanced Accessed Control (M3): This mitigation upgrades our employee ID access badges and card readers to technology that will address vulnerabilities and prevent manipulation of the cards and badges for purposes of gaining unauthorized access.
- Enhanced Metal Theft Abatement (M4): This mitigation will increase the number of sites that are scheduled for improvements to the perimeter barrier security.
- Advanced Surveillance Technology – AST (M5): This mitigation looks to pilot the deployment of advanced surveillance technology at various facilities. Advanced Surveillance Technology is a term used to broadly describe several categories of technology – ranging from autonomous to semi-autonomous, manually operated, static or fixed location, and wearable surveillance solutions. The technologies include, but are not limited to, Autonomous Security Robots (ASRs), Unmanned Ground Vehicles (UGVs), and Unmanned Aerial Systems (UAS), also known as drones.

SCE has developed three risk mitigation plans:

- The Proposed Plan continues existing programs (C1, C2, C3, C4, & C5), rolls out the second and third phases of the Smart Key Program (M2 & M3), and improves our Access Control (M3).
    - Alternative Plan #1 continues existing programs (C1, C2, C3, C4, & C5), rolls out all of the final two phases of the Smart Key Program (M1 & M2), improves our Access Control and perimeter barriers (M3 & M4), and adds Advanced Surveillance Technology (M5).
    - Alternative Plan #2 continues existing programs (C1, C2, C3, C4, & C5), and adds the Advanced Surveillance Technology (M5).

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Major Physical Security Incident, based on the Proposed Plan discussed below.[3]

Table I-1
Summary of Pre- and Post- LoRE and CoRE Risk Scores[4]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Major Physical Security Incident	256.2	0.003	0.71	211.4	0.003	0.63

C. Sensitive, Confidential Information Must Be Protected

SCE may be unable to share information beyond a certain level of detail to protect sensitive and confidential security data. Exposing details about SCE's security protocols could compromise the integrity and confidentiality of our physical security approach, enabling an attacker to avoid or defeat the security safeguards.

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3 LoRE – likelihood of risk event. CoRE – consequence of risk event. Risk Score is the product of the LoRE and CoRE. For additional information on the risk modeling methodology, please refer to Chapter 2 – Risk Model and Methodology.

4 Refer to Major Physical Security Risk Model (excel file).

This chapter discloses information in a manner that does not compromise SCE's physical security. To promote transparency and help the Commission (or appropriate stakeholders) access additional and sensitive information that might be necessary to answer specific questions, SCE can provide an in-person meeting, facilitate virtual secure information sharing, or take other reasonable measures to convey information to the Commission in a manner that appropriately recognizes the need to protect certain information from falling into the wrong hands.

II.

RISK ASSESSMENT

A. Risk Definition and Scope

SCE maintains operations at more than nine hundred facilities across our 50,000-square mile service territory. Each facility has various assets that may require distinct levels and types of security controls or mitigations – e.g., electrical equipment, communication technology, vehicles, workers, etc. The physical security needs of each facility can be unique. For example, a high-risk facility, such as a critical transmission substation, may require a more robust physical security posture. If SCE's high-risk substations and/or their associated primary control centers are rendered inoperable or damaged as a result of a security breach, it could compromise our ability to deliver power safely and reliably to our customers. The National Research Council has noted that a carefully planned and executed attack could "deny large regions of the country access to bulk system power for weeks or even months."[5]

In contrast, a lower-risk facility, such as a laydown yard that houses material inventory for ongoing work, may require fewer controls or mitigations. Moreover, office buildings may require different levels and types of security controls or mitigations based on the overall risk. The overall risk takes into consideration, at a minimum, the criticality, occupancy level, and operations that occur at each location.

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[5] National Research Council (2012). Terrorism and the Electric Power Delivery System. Washington, DC: The National Academies Press. https://doi.org/10.17226/12050, Retrieved from http://www.nap.edu/catalog/12050/terrorism-and-the-electric-power-delivery-system. This is a study completed by several organizations on the impact of coordinated attacks on the power grid. It discusses vulnerability based on several factors and examines potential effects on the economy and the health/welfare of society.

The scope of this chapter is defined in Table II-2 below.

Table II-2
Physical Security RAMP Chapter Scope

IN SCOPE	• Acts that occur within the security perimeter of SCE facilities that are protected by physical security measures. Facilities in-scope include office buildings, substations, switching centers, grid control centers, data centers, electricity generation facilities, IT facilities, warehouses, and service centers. • Acts that occur within SCE perimeters such as rights-of-way, easements, and other land that is within SCE's property line but might not have full security measures. An example is trespassers that are outside SCE's security perimeter but within SCE's property line boundaries. • Public safety incidents resulting from criminal activity that occur as a result of a member of the public's unauthorized interactions with SCE's electric and/or non-electrical assets that are sited within SCE's security property line.
OUT OF SCOPE	• Acts that occur beyond the security property line of SCE facilities. This includes incidents affecting power lines, poles and transmission towers located outside of SCE substations regardless if they are on rights-of-way, easements, and other land. It also includes incidents occurring when SCE field workers perform work on or around a customer's property. There are no reasonable and substantial physical security measures to protect assets that are located beyond SCE facilities. • Public safety incidents resulting from criminal activity that occur as a result of the public's unauthorized interactions with SCE's electric and/or non-electric assets that are sited outside of the security perimeter of SCE facilities.

B. <u>Physical Security Threats to Electric Utilities</u>

The internal and external threats facing the utility industry continue to evolve. Between 2015 and 2021, electric utilities reported to the U.S. Department of Energy a total of 359 physical attacks/sabotage/vandalisms that caused outages or other power disturbances, and an additional 97 suspicious activity events that threatened physical security with the potential to degrade facility operations.[6] California and other western states have experienced several major incidents in the past, including harm to individuals. A few examples are listed below:

- In 2011, an SCE employee shot and killed two SCE managers, and wounded an SCE employee and a contract worker before committing suicide. This incident occurred at a secure SCE facility located in a gated complex equipped with access control measures.
- In 2013, unknown attackers unleashed a coordinated attack on PG&E's Metcalf Substation in Northern California. The attackers severed six underground fiber-optic lines before firing more than 100 rounds of ammunition at the substation's transformers, causing more than $15 million in damage. The intentional act of sabotage, likely involving more than one gunman, differed from any previous attack on the nation's grid in its scale and sophistication. Metcalf Substation is within a relatively short distance of highly-populated areas, and it supplies electricity to Silicon Valley.
- Between 2017 and 2021, there were five reported safety incidents where intruders either suffered serious injury or fatality within SCE substations.
- In 2018, the President's National Infrastructure Advisory Council (NIAC) studied the potential impact of a "Black Swan" event in its 2018 report, "Surviving A Catastrophic Power Outage: How to Strengthen the Capabilities of the Nation." The NIAC was "tasked to examine the nation's ability to respond to and recover from a catastrophic power outage of a magnitude beyond modern experience, exceeding prior events in severity, scale, duration, and consequence." The NIAC was asked to answer the question: "Simply put, how can the nation best prepare for and recover from a catastrophic power outage, regardless of the cause?" They concluded that public-private action involving all levels of government and the

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[6] Data from 2015 – 2021 taken from OE-417 Annual Summaries. (https://www.oe.netl.doe.gov/OE417_annual_summary.aspx).

private sector would be needed to prepare for and respond to a no-notice or limited notice catastrophic power outage caused by or complicated by a physical/cyber attack.[7]

- In June 2020, three men identified as being members of an extreme right-wing movement were arrested in Las Vegas. They were charged with conspiracy to damage and destroy by fire and explosives and possession of unregistered firearms. They had planned to attack an electrical substation and an electric generation plant. All three were current or former U.S. Military personnel.
- In August 2021, four men, allegedly part of a neo-Nazi group, were charged in federal court with planning to attack electrical infrastructure in Idaho and the Northwest. Some of these men were active or former U.S. Military personnel, and all four had actively researched and reviewed a previous attack on the power grid. Their plans included using firearms and explosives in their attack against the grid.

Moreover, the former Secretary of the Department of Homeland Security (Michael Chertoff) predicted a future attack in the U.S. that would exceed the sophistication and resulting damage of Metcalf, including the possibility of a combined physical and cyber-attack.[8] The combination of a physical and cyber-attack is a concern, because many of the cyber assets deployed in the field require the protection of physical security mitigations. These physical security mitigations for the cyber assets are in large part mandated by NERC. This is due to the particular vulnerabilities that may exist when deploying cyber assets out in field locations. A coordinated cyber and physical attack scenario was utilized last year in NERC's GridEx exercise.[9]

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[7] It is quite possible that an attack on SCE facilities or grid assets may occur as a combination of physical and cyber assaults. For granularity in RAMP risk analysis, SCE has modeled physical and cyber security risks separately, and has discussed them in dedicated chapters. Our approach is not intended to suggest that an inter-relationship cannot occur in these two risks, as well as the coordinated response to such a combined attack. Further discussion on the relationship between cyber and physical security is provided below.

[8] "Physical Security in the U.S. Power Grid: High-Voltage Transformer Substations" (https://www.documentcloud.org/documents/1303171-2014-crs-report.html) at p. 29.

[9] GridEx is the largest grid security exercise in North America, and is hosted every two years by NERC's Electricity Information Sharing and Analysis Center (E-ISAC). It serves as a critical benchmark that

(*Continued*)

These examples illustrate the types of physical security threats that this chapter addresses. The increasing complexity and volume of physical threats facing SCE requires that we leverage an array of security control and mitigation measures to deter, detect, delay, assess, and promptly respond to threats and hazards.

SCE's controls and mitigations provide a layered approach to help ensure the safety and security of SCE workers, visitors, facilities, assets, and equipment. A layered approach refers to multiple security measures deployed in various locations throughout the facility, to help provide overlapping layers of protection. For example, the perimeter of the property may be the first line of defense, the exterior of the building the second line, and the interior of the building the third line. A layered approach reduces the risk of unauthorized persons gaining physical access to restricted areas. We describe this approach in more detail in Section VII.

C. Risk Bowtie

To define and evaluate SCE's Physical Security risk, SCE used a bowtie approach similar to the 2018 RAMP submission, as shown in Figure II-1. Each component of the bowtie represents a critical data point sourced from internal and external data and information. SCE explains these components in detail in the sections that follow.

There are notable similarities as well as differences between the 2018 and the 2022 RAMP bowties. The exposure in the 2018 RAMP consisted of office buildings, substations, switching centers, grid control centers, data centers, electric generation facilities, IT facilities, warehouses, and service centers. Those same facility types are included in the 2022 RAMP scope, listed under exposure on the risk bowtie. Along with the aforementioned facility types, we also added Battery Energy Storage Systems (BESS), identified as "battery storage."[10]

Regarding the core bowtie elements of drivers and outcomes, we have made an adjustment to account for evolving risks such as Gunfire/Projectile Penetration, Unmanned Aerial System (UAS)

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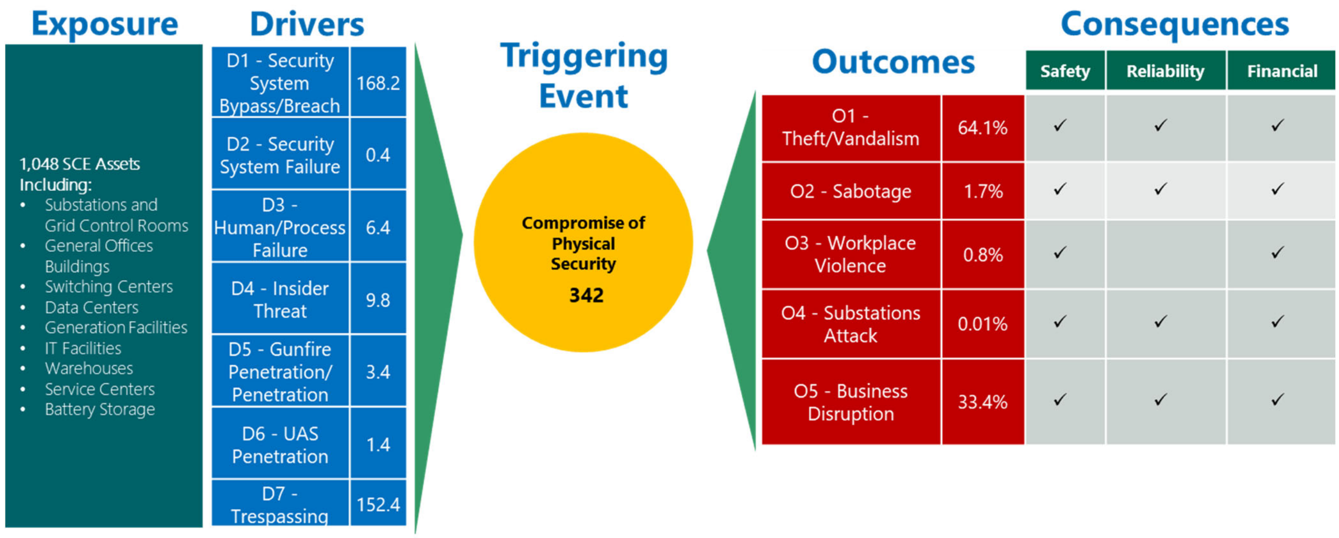
maximizes the ability of organizations to coordinate with neighboring utilities and reliability coordinators to effectively exercise and address grid reliability issues.

[10] The growing importance of BESS is discussed in Appendix A.

Penetration, and Trespassing. Trespassing was labeled as an outcome in our 2018 RAMP. But after further evaluation and examination of lessons learned, we determined that it was more appropriate for Trespassing to serve as a driver to encapsulate incidents that occur outside SCE's security perimeter but fall within SCE property line. One example is the increased risk from trespassing on SCE property for the purpose of establishing unauthorized encampments. The triggering event is the same as the 2018 RAMP risk titled Compromise of SCE Physical Security.

The outcomes identified in our 2022 RAMP include Theft/Vandalism, Sabotage, Workplace Violence, Substation(s) Attack, and Business Disruptions. In the 2018 RAMP, the outcomes were Theft, Trespassing, Workplace Violence, and Coordinated Attack on Multiple Substations. The Theft outcome has been broadened to include incidents of vandalism such as cutting fences cuts and spraying graffiti. Other refinements include adding Sabotage and Business Disruption as outcomes, and changing the nomenclature of "Coordinated Attack on Multiple Substations" to "Substations Attack." SCE explains these components in detail in the sections that follow.

Figure II-1
Risk Bowtie for Major Physical Security Incident[11]



D. <u>Drivers</u>

SCE identified seven drivers for this risk: D1 (Security System Bypass/Breach), D2 (Security System Failure), D3 (Human/Process Failure), D4 (Insider Threat), D5 (Gunfire/Projectile Penetration), D6 (UAS Penetration), and D7 (Trespassing). Table II-3 shows the historical frequency for each of these drivers.

[11] Please refer to WP. Ch. 11 - Baseline and Risk Inputs.

Table II-3
Historical Driver Frequency

Drivers	2017	2018	2019	2020	2021	Total (2017 -2021)	Annualized Avg.
D1 - Security System Bypass/Breach	128	111	164	197	241	841	168.2
D2 - Security System Failure	0	1	1	0	0	2	0.4
D3 - Human/Process Failure	4	9	3	2	14	32	6.4
D4 - Insider Threat	16	9	15	6	3	49	9.8
D5 - Gunfire/Projectile Penetration	3	0	4	5	5	17	3.4
D6 - UAS Penetration	1	2	0	4	0	7	1.4
D7 - Trespassing	130	113	102	104	313	762	152.4
Totals	**282**	**245**	**289**	**318**	**576**	**1,710**	**342.03**

1. D1 - Security System Bypass/Breach

Security System Bypass/Breach is defined as an unauthorized intrusion into a secured location, accomplished by evading the security system or breaching the security perimeter. Some potential examples of Security System Bypass/Breach include:

- Intruder(s) cutting the perimeter fencing, barbed wire, and/or locks to enter SCE substations, laydown yards, and facilities.
- Intruder(s) evading the security system through tactics such as subversive tailgating[12] of authorized persons.
- Intruder(s) trespassing onto SCE substations, laydown yards, and facilities by climbing over or crawling under perimeter fencing.

Potential motives for Security System Bypass/Breach include:

- Theft of SCE property (e.g., copper, tools, and/or equipment).
- Intention to commit acts of sabotage, attack, or workplace violence.

[12] "Tailgating" is a term that refers to an intruder gaining access to an SCE facility by following immediately behind an authorized SCE worker who is going into the facility.

SCE estimates an annual frequency of 168 incidents related to Security System Bypass/Breach. We derived this estimate by analyzing actual incidents from SCE's internal incident database for 2017-2021 and external data from NERC's Electricity Information and Sharing and Analysis Center (E-ISAC).

2. <u>D2 - Security System Failure</u>

Security System Failure refers to a compromise of physical security occurring due to security technology or systems failing. In other words, the suspect breached the facility because the security technology failed to serve its intended function, whether that function is deterring, detecting, delaying, assessing, and/or responding to the threat. Some examples include:

- Security system failure from vegetation growth or weather that may impair security technology (cameras, video analytics) or corrode walls or fencing;
- Wildlife that may damage the security system;
- Technological malfunction where the intended solution does not properly secure a facility, recognize the movement of a suspect, or otherwise warn or detect as intended.

SCE estimates an annual frequency of 0.4 incidents related to Security System Failure. This estimate was derived by analyzing actual incidents from SCE's internal incident database for 2017-2021.

3. <u>D3 - Human/Process Failure</u>

This driver considers the failure of an SCE worker to follow policies, procedures, or protocols, or the absence of adequate processes in place that address physical security vulnerabilities. Some examples of Human/Process Failure include:

- Lack of security awareness and absence of best security practices. An example of such practices is ensuring that all vehicles and facilities within SCE facilities (such as an office parking lot) are locked with all valuables stored and secured out of sight.
- SCE workers (including security personnel) violating Company policy, leading to unauthorized access into a secure facility. One example is an unauthorized person

gaining entry into an SCE facility by being allowed to tailgate behind an authorized SCE worker who is going into the facility.

SCE estimates an annual frequency of six incidents related to Human/Process Failure. We derived this estimate by analyzing actual incidents from SCE's internal incident database for 2017-2021.

4. <u>D4 - Insider Threat</u>

Insider Threat arises when an SCE worker uses current or previous access to facilities or insider knowledge with malicious intent. Consequently, an actual breach of security may not need to occur to commit the intended crime; the SCE worker may already have access. Some examples of potential incidents that would be considered Insider Threat include:

- A recently terminated employee using status and relationships to access SCE facilities and harm those inside the facility.
- An employee using access to critical infrastructure to cause reliability incidents or widespread blackouts.
- An employee using their access without authorization to physically remove intellectual property or confidential information from SCE facilities.
- An employee or contractor providing information to third parties to support or enable a security breach.

SCE forecasts approximately ten Insider Threat incidents per year. This estimate is based on SCE internal incident data from 2017 – 2021, and a 2011 incident of workplace violence at SCE (discussed above).

5. <u>D5 – Gunfire/Projectile Penetration</u>

Gunfire/Projectile Penetration relates to instances where a facility is compromised by gunfire or projectiles, which can lead to asset damage, outages, safety risks, and financial impact from repairing electrical assets. The frequency was derived from SCE internal data and peer utility data. Some examples of Gunfire/Projectile Penetration include:

- Electrical assets damaged from gunfire or projectiles

- External gunfire or projectile(s) causing a risk of harm to people within the facility

SCE estimates an annual frequency of four incidents related to Gunfire/Projectile Penetration. This estimate was derived by analyzing actual incidents from SCE's internal incident database for 2017-2021 and external data from NERC's Electricity Information and Sharing and Analysis Center (E-ISAC).

6. <u>D6 - UAS Penetration</u>

UAS Penetration involves the compromise of physical security from an Unmanned Aerial System UAS. There has been an upward trend in the number of UASs that hover over facilities with cameras, as well as UASs crashing into substations, including crashing into electrified equipment. Nationally and internationally, drones have been used with malicious intent against electrical assets. The frequency was derived from SCE internal data and peer utility data in the E-ISAC report. UAS Penetration would also encompass the use of a UAS to damage or attack SCE equipment.

7. <u>D7 – Trespassing</u>

This driver represents an intruder(s) trespassing onto SCE substations, easements, rights-of-way, laydown yards, and other parts of SCE property that are within SCE property lines but not necessarily within the respective facility. This includes instances when:

- Encampments are established away from SCE facilities but within SCE's property line. These encampments can pose a risk to SCE's personnel, facilities, assets, and to the trespassing individuals themselves.
- Intruder(s) trespassing onto energized substations, service center yards, and laydown yards intending to steal copper, tools, equipment, or vehicles.

SCE estimates an annual frequency of 152 incidents related to Trespassing. We derived this estimate by analyzing actual incidents from SCE's internal incident database for 2017-2021 and external data from NERC's Electricity Information and Sharing and Analysis Center (E-ISAC).

E. Triggering Event

The triggering event for the risk bowtie is a "compromise of SCE physical security." This is defined as occurring when the physical security perimeter is compromised by unauthorized access, or when an insider compromises SCE's physical security, resulting in an adverse outcome.

F. Outcomes and Consequences

SCE identified and evaluated the following outcomes that can occur when SCE physical security has been compromised: (1) Theft/Vandalism, (2) Sabotage, (3) Workplace Violence, (4) Substation(s) Attack, and (5) Business Disruption. Please refer to Table II-4 below. To generate the likelihood of each outcome occurring, we assessed internal data (i.e., SCE's investigation database), external data (i.e., sabotage-related data reported by peers), and input from experts in physical security.[13]

Table II-4
Historical Outcome Frequency

Outcomes	2017	2018	2019	2020	2021	Total (2017 -2021)	Annualized Avg.	% of Outcomes
O1: Theft/Vandalism	174	155	198	247	322	1096	219.2	64.1%
O2: Sabotage	1	1	4	15	8	29	114.2	1.7%
O3: Workplace Violence	3	2	5	2	2	14	2.8	0.8%
O4: Substations Attack	0.03	0.03	0.03	0.03	0.03	0.17	5.8	<1%
O5: Business Disruption	104	87	82	54	244	571	0.03	33.4%
Totals	**282**	**245**	**289**	**318**	**576.03**	**1,710**	**342.03**	**100.0%**

1. O1 – Theft / Vandalism

In this outcome, a suspect steals or vandalizes SCE and/or personal property. Some of the most common incidents involve the theft of metal (copper), tools, and equipment. In a real-life example, damage from multiple metal thefts at an SCE substation in 2021 resulted in the substation being decommissioned.

SCE experienced an increase in theft and vandalism incidents on SCE property, from 247 incidents in 2020 to 322 incidents in 2021. This represents a year-over-year increase of 30%.

[13] Please refer to WP. Ch. 11 - Baseline and Risk Inputs.

Specifically, during this period, metal theft increased from 57 to 112 incidents, which is a 96% year-over-year increase.

SCE used CPUC-reportable public serious injury and fatality data to derive the safety consequences related to suspects committing theft or vandalism. For purposes of this chapter, reliability impacts are a result of service interruptions caused by theft and vandalism, and financial costs are a result of property loss due to theft.

2. <u>O2 – Sabotage</u>

The scope of sabotage includes instances when suspects disrupt or attempt to disrupt substation operations at a single facility. These incidents could impact the bulk electric system on a widespread basis, with consequences including serious injuries, fatalities, reliability, and financial loss. Sabotage represents a scaled-down version of the substations attack (O4) outcome. Sabotage occurs when suspects compromise a facility in some preplanned manner and aim to damage security technology, electrical operations, or take some other harmful action that impacts SCE's ability to provide safe and reliable service.

Potential consequences include the safety of employees or other authorized personnel, reliability due to tampering with or damaging electrical facilities, and financial costs resulting from the need to repair or replace assets.

3. <u>O3 – Workplace Violence</u>

The scope of the workplace violence outcome includes incidents that could result in a serious injury and/or fatality. The U.S. Department of Labor's Occupational Safety and Health Administration (OSHA) defines workplace violence as any act or threat of physical violence, harassment, intimidation, or other threatening disruptive behavior that occurs at the worksite.
For purposes of this RAMP analysis, we only captured the threat of cases that resulted in serious injury or fatality.

4. <u>O4 – Substations Attack</u>

This outcome results in a coordinated attack on multiple substations. This could impact the bulk electric system on a widespread basis, with consequences including serious injuries, fatalities, reliability, and financial loss. According to the Congressional Research Service, a coordinated and simultaneous attack on substations would be catastrophic, with severe implications over a large geographic area and extended blackouts being suffered. Fortunately, such an attack has not occurred in the United States to date. However, as noted above in Section II.B, there have been at least two notable arrests of small groups of suspects in the past two years that were well-trained and highly motivated to carry out multiple attacks against the grid. Such an attack is possible in SCE's service territory, given the following:

- The increased frequency of sabotage attempts in the United States between 2011 and 2021 (e.g., the 2013 Metcalf Substation attack, the 2013 500kV substation attack in Lonoke County, and others).
- The Southern California region is home to several major industries, is a large population center, serves as a substantial hub of media and mass communications, and includes centers for key national infrastructure. All of these crucial areas rely on SCE's electric infrastructure to function. Therefore, an attack against SCE's BES provides politically-motivated attackers with a high-visibility target and potential for broad disruption.

Accordingly, SCE developed a scenario that is analogous to the scenarios in NERC's 2015 Grid Security Exercise – GridEx III and 2021 Grid Security Exercise – GridEx VI.

This exercise showed the potential results of this type of coordinated attack on multiple substations and the loss of critical grid components, as well as unauthorized access to substations and serious injuries and/or deaths to employees or members of the public.

5. O5 – Business Disruption

Business Disruptions involve incidents that do not fall into the other outcome categories; normally, these are relatively minor incidents. This outcome encompasses situations such as removing trespassers, environmental cleanup, removing items from SCE energized equipment such as fallen drones, incidents requiring the direct intervention of a security officer, facility evacuations, small localized fires, and other instances that disrupt business operations.

For example, potential consequences include safety, reliability, and financial loss. Safety concerns are implicated in terms of items such as trespasser(s) assaulting SCE workers and authorized personnel. Reliability risks could result from, for example, drones that fall and damage electrical assets or instances of incidental or indirect gunfire or projectile penetration that are not directed at SCE but impact our assets. Financial cost examples include having to repair or replace electrical assets, or homeless encampment clean-up costs.

G. Tranches

The scope of physical security risk is separated into three tranches: (1) Grid Operations, which focuses on the protection of electrical sites that impact the grid, (2) Major Business Functions, including the protection of non-electrical sites such as general office buildings, call centers, switch centers, warehouses, IT facilities, service centers, and (3) Generation Capabilities, including the protection of water treatment plants, dams, battery storage, etc.

We chose to separate the risk into three tranches because SCE's physical security program mitigations are based on the facility type and unique function. The tranche groupings also align with prior SCE risk-related regulatory filings, including SCE's 2018 RAMP and Test Year 2021 GRC. In the context of these filings, the three tranches of Protection of Grid Operations, Protection of Major Business Functions, and Protection of Generation Capabilities map to the corresponding GRC activities, which aids transparency and integration between RAMP and the GRC.

Alternative approaches we considered included basing tranches on site size or geographical location (e.g., rural vs. urban), or based upon other internal SCE project/program activities. Ultimately, these were not viable options because the type of risks that are being mitigated is not similar, even if the two facilities are similarly-sized or located in similar geographic locations. For example, a critical and remote specialized facility in a rural location and a remote standard office building in a rural location, even if similarly sized, have markedly different physical security profiles.

Table II-5 below summarizes the tranche level risk analysis for Physical Security.[14]

Table II-5
Tranche Level Risk Exposure

Risk Tranche	Tranche Exposure (# of Assets/Facilities)	% of Risk Exposure	LoRE / TEF
T1 - Grid Operations	894	85%	188
T2 - Major Businesss Functions	64	6%	144
T3 - Generation Capabilities	90	9%	11
System Total	**1,048**	**100%**	**342**

H. Related Factors

For purposes of this discussion, SCE defines related factors as those not directly included in the risk modeling, but that have the potential to impact the driver frequency and the likelihood of certain outcomes. Related factors for the Physical Security chapter of RAMP include climate change, seismic events, wildfire exposure, extreme weather, pandemic, and political extremism which could impact components of the bowtie analysis. These risk factors are explained qualitatively below in Table II-6. Based on current data collecting abilities, we are not able to quantitively show how they impact the risk bowtie components.

[14] Please refer to WP. Ch. 11 - Baseline and Risk Inputs.

Table II-6
Related Factors Impacting Physical Security

Related Factor	Impact Description
Pandemic	Pandemic risks and resulting lockdowns have the potential to impact the temperament of the populace leading to a possible increase in crime rates, civil unrest, and supply chain disruptions. Secondary effects include increased physical security risk and reduced local law enforcement capacity to respond to incidents.
Climate Change	Increased temperatures have a correlation with civil unrest, financial insecurity, crime rates, and other factors that could increase the potential for physical security incidents against SCE assets (see https://www.ncbi.nlm.nih.gov/pmc/articles/PMC7007136/).
Seismic	A severe seismic event can damage security mitigation measures (e.g., block walls, fences, camera viewing), and broad events can contribute to the potential for insecurity and civil unrest, driving the potential for physical security incidents against SCE assets.
Wildfire Exposure	Wildfires damage physical security measures and can potentially leave a facility vulnerable to crime such as theft.
Extreme Weather	Extreme weather can cause damage to security equipment or interfere with their efficiency at detecting potential incidents.
Political Extremism	Political extremism can lead to planned attacks on substations and other SCE sites.

III.

COMPLIANCE

Below, SCE describes the two compliance activities related to the NERC, and activity related to CPUC Decision D.19-01-018 (also referred to as SB-699). As outlined in Chapter 2: Risk Model and RSE Methodology, compliance-based work is not modeled in this RAMP.

A. CM1 – Physical Security Reliability Standard NERC CIP-014

NERC CIP-014 was established in 2014 and approved by the Federal Energy Regulatory Commission (FERC) as a standard to protect transmission substations, and their associated primary control centers, against physical attack. NERC CIP-014 has been effective since January 26, 2015, and encompasses threat and vulnerability assessments to identify potential threats, weaknesses, and corresponding risks. Under the standard, utilities must perform an initial assessment followed by an independent third party review. Utilities subsequently perform a more tailored assessment and evaluation of potential threats, and the associated vulnerabilities related to each identified critical location.

Finally, the utility must develop and implement a plan to protect those identified assets from physical threats, and have that plan verified by an independent third party. The sites identified as being most critical in relation to the grid (based upon established NERC CIP-014 criteria) have the verified security measures implemented. The difference between these electrical sites and the electrical sites pertaining to C1 – Protect of Grid Operations, is that these sites are deemed NERC-critical and are subject to certain specific compliance requirements.

B. CM2 – NERC CIP-003-v6

On January 21, 2016, in order No. 822, FERC approved NERC CIP-003-v6 to establish physical security controls to protect the Low Impact BES Cyber System. These controls require policies for each Responsible Entity (e.g., SCE) to restrict physical access to our BES facilities based on needs as determined by the Responsible Entity. This compliance mitigation focuses on the physical protection of Low Impact BES cyber systems within SCE facilities. Physical protection of the identified cyber systems involves security measures such as metal cabinets, card readers, and more to restrict access to those individuals with proper authorization.

C. CM3 – Physical Security of Electrical Infrastructure

On January 10, 2019, CPUC Decision (19-01-018) was issued, requiring California utilities to address the physical security risks to their distribution systems. This Decision requires electric utilities to identify electric distribution assets that may merit special protection and measures to lessen identified risks and threats. In order to address the risk of a long-term outage to an identified distribution facility, each electric utility was required to develop and implement a Security Mitigation Plan.

This compliance measure differs from those for our typical distribution sites, which are addressed in C1- Protection of Grid Operations. This Decision focuses on identified distribution assets that serve customers meeting one of the seven criteria listed within the Decision. The assets identified in scope for this Decision were assessed to be lacking electrical system redundancies or adequate physical security measures, and thus the Commission concluded that the assets merited additional security mitigations.

IV.

CONTROLS

SCE has controls in place to minimize the physical security risks that exist across SCE's facilities. These controls are scoped to protect facility classes within SCE's facility portfolio, including grid infrastructure (substations), generation facilities, and major business facilities (office buildings, warehouses, service centers, etc.). Because not every facility addressed in these controls will have the same risk exposure, the actual set of physical security measures at each facility may vary. Hence, similar to the physical security programs described in our GRC filings, we present our controls on a program basis. SCE has been employing these compliance activities and controls as critical components of our layered defense protection approach.

Table IV-7 below maps existing controls to drivers, outcomes, and consequences. The table also indicates if the control was found in SCE's 2018 RAMP, and notes whether the control is included in the proposed and/or alternative plans.

Table IV-7
Inventory of Physical Security Controls

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed or Alternative Plan(s)?
C1	Protection of Grid Operations	D1, D2, D3, D4, D5, D6, D7	-	-	Yes	All
C2	Protection of Generation Capabilities	D1, D2, D3, D4, D5, D6, D7	-	-	Yes	All
C3	Protection of Major Business Functions	D1, D2, D3, D4, D5, D6, D7	-	-	Yes	All
C4	Asset Protection	D1, D2, D3, D4, D5, D6, D7	-	-	Yes	All
C5	Smart Key Program: Phase 1	D1, D2, D3	-	-	Yes	All

A. C1- Protection of Grid Operations

Protection of Grid Operations is an existing program that helps secure SCE's electric facilities against physical threats. These facilities primarily consist of substations and their respective control centers. This control is deployed based on the overall risk, which considers the criticality of the asset and the potential impact of a breach. Criticality is defined by SCE T&D (Transmission & Distribution) engineers assessing the amount of load served, the number of network connection points, and other factors for each substation.

Through this control, SCE deploys various physical security measures that mesh together to actively deter, detect, delay, assess, and respond to threats using a layered defense approach. These measures can include an appropriate combination of access control, alarms, perimeter protection barriers (e.g., fencing, walls, barbed wire, etc.), video surveillance and analytics, incident tracking and analysis, and other measures. SCE continuously assesses the threat landscape and tailors the security measures for each substation accordingly. For example, when a substation has been identified as being a target of multiple incidents of copper theft, several temporary or permanent mitigations are employed.

These mitigations can include security officers, high-security fencing, and/or video surveillance, all to deter suspects from the illicit activity.

This control is included in all three plans; Proposed, Alternative Plan 1, and Alternative Plan 2. This control will continue the deployment, scope, and features of the existing controls in place at electrical facilities. These activities include, but are not limited to, the following:

- Upgrading fencing
- Improving lighting
- Block Wall Protection
- Visitor Management
- Perimeter Detection/ Analytics
- Updating the processes to identify facilities that need improved monitoring by a combination of security cameras and other technology
- Deploying permanent or temporary uniformed security officers
- Improving access management and control processes

1. <u>Drivers Impacted</u>

Both the Proposed Plan and alternatives for this control (C1) can impact all drivers. For example, physical barriers such as walls and gates, as well as video surveillance and/or improved lighting, can reduce the frequency of D1 (System Security Breach/Bypass) and D7 (Trespassing). Updating security processes and access management systems can reduce the frequency of D3 (Human/Process Failure). Access restrictions for employees can reduce the frequency of D4 (Insider Threat) by granting access to only those areas where the employee specifically needs access to accomplish their job duties.

B. <u>C2 – Protection of Generation Capabilities</u>

Protection of Generation Capabilities is an existing control that aims to protect SCE's generation facilities against physical threats. This control implements most of the security measures used in the Protection of Grid Operations (C1), such as access control, alarms, perimeter protection such as high-security fencing, block walls and steel gates, and video surveillance. However, C2 tailors these measures to fit the generation asset's landscape and configuration. For example, our hydro facilities are often located in rural or remote areas, and the hydro facility complex may cover a vast amount of territory. This control can also include enhanced security measures to meet the specific and unique needs of the generation facility being protected. Types of generation facilities include hydroelectric facilities (i.e., dams, powerhouses or stations), natural gas-fired plants, solar facilities, Battery Energy Storage Systems (BESS), Reliability Utility Owned Energy Storage (RUOES), and other supporting facilities and infrastructure.

1. Drivers Impacted

C2 can impact all drivers. For example, physical barriers such as walls and gates, as well as video surveillance and/or improved lighting, can reduce the frequency of D1 (System Security Breach/Bypass) and D7 (Trespassing). Updating security processes and access management systems can reduce the frequency of D3 (Human/Process Failure). Access restrictions for employees can reduce the frequency of D4 (Insider Threat) by granting access to only those areas where the employee specifically needs access to accomplish job duties.

C. C3 – Protection of Major Business Functions

This control protects SCE's non-electric facilities against physical threats. Non-electric SCE facilities include corporate general offices, service centers, business offices, call centers, data centers, and warehouses. Security fencing and gates similar to what is used in C1 (Protection of Grid Operations) and C2 (Protection of Generation Capabilities) may be used to protect service centers, data centers, and warehouses in industrial environments. A combination of uniformed security staff, access controls, video surveillance, and security alarms are typically used to protect corporate offices and business offices located in urban environments. The combination of security measures deployed to each location is uniquely tailored to the functions, criticality, and overall security risks of each facility.

1. Drivers Impacted

C3 can impact all drivers. For example, physical barriers such as walls and gates, as well as video surveillance and/or improved lighting, can reduce the frequency of D1 (System Security Breach/Bypass) and D7 (Trespassing). Updating security processes and access management systems can reduce the frequency of D3 (Human/Process Failure). Access restrictions for employees can reduce the frequency of D4 (Insider Threat) by granting access to only those areas where the employee specifically needs access to accomplish their job duties.

D. <u>C4 – Asset Protection</u>

Asset Protection is an existing control that helps protect SCE workers and facilities against physical threats. With this control, SCE can: 1) properly vet SCE workers via a background investigation before hiring; 2) investigate security incidents and concerns; 3) train employees on preventing workplace violence and responding safely and appropriately to active shooter incidents; 4) deploy the Threat Management Team (TMT) to assess threats to SCE workers; and 5) employ security officers to protect facilities and respond to security threats and incidents. This control will continue during the duration of the 2022 RAMP period with the annual updates to the Insider Risk and Workplace Violence & Security Awareness training modules.

1. <u>Drivers Impacted</u>

The physical security measures in this control are designed to impact all drivers. The frequency of drivers D1 (Security System Bypass/Breach) and D3 (Human/Process Failure) are reduced by deploying security officers to deter violence and property crimes, observe and report security incidents, control access to facilities, and provide immediate response capability. The Insider Threat program reduces the frequency of D4 (Insider Threat) by identifying potential threats before they materialize.

E. <u>C5 – Smart Key Program: Phase 1</u>

This control continues the use and implementation of Smart Key technology at the identified critical facilities that are within scope. Smart Key technology replaces conventional locks and keys, such as those found at electric facilities, generation facilities, and office buildings. Smart Keys include both mechanical and electronic features, and integrate with SCE's access control system. Smart Keys allow different access authorizations to be assigned to specific individuals. They are configured to have a set expiration period. This reduces the possibility and consequences of unauthorized use when a key is lost or stolen.

The benefits of Smart Keys include greater effectiveness in controlling access with a time-and-date stamped record of every use, reduced perimeter security vulnerabilities, reduced consequences of lost or stolen keys, and greater employee accountability in managing keys.

SCE C5 continues the use and implementation of Smart Keys through Phase 1 from the previous RAMP period. Phase 1 calls for installing approximately 130 smart keys at SCE's most critical facilities.

1. Drivers Impacted

The Smart Key Program (C5) will impact D1 (Security System Bypass/Breach) and D3 (Human/Process Failure) by helping prevent unauthorized access and providing greater accountability for the use of keys.

Smart Keys can also detect unauthorized access attempts; such detection can alert SCE to concerning behavior that would be subject to prompt investigation, and corrective action as warranted.

V.

MITIGATIONS

Beyond the compliance and control activities described in Sections III and IV, SCE monitors and evaluates effective ways to respond to and mitigate evolving security threats by expanding the use of current technology and prudently implementing new technology and procedures. These efforts are summarized in Table V-8 below.

Table V-8
Inventory of Physical Security Mitigations

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed or Alternative Plan(s)?
M1	Smart Key Program: Phases 2	D1, D2, D3	-	-	Alt Plan #1	Proposed
M2	Smart Key Program: Phases 3	D1, D2, D3	-	-	Alt Plan #1	Proposed
M3	Enhanced Access Control	D1, D2, D3, D4	-	-	No	Proposed
M4	Enhanced Metal Theft Abatement	D1, D7	-	-	No	Alternative Plan #1
M5	Advanced Surveillance Technology (AST)	D1, D2, D3, D4, D5, D6, D7	-	-	No	Alternative Plan #2

A. M1 & M2 – Smart Key Program: Phases 2 & 3

As mentioned in C5 – Smart Key Phase 1, this is a technology that is implemented at critical electrical sites. M1 and M2 expand the deployment of the same technology (and associated benefits and mitigation effectiveness) to a larger inventory of facilities. These additional facilities include the remaining electrical sites that were not part of Phase 1, plus non-electrical facilities and generation facilities. M1 and M2 provide similar benefits as C5 – Smart Key Phase 1, except at more facilities and additional types of facilities.

SCE has considered extending the Smart Key technology solution through two phases over the RAMP period:

- Phase 2 (M1): Install 800 smart keys at the remaining SCE electrical facilities
- Phase 3 (M2): Install 300 smart keys at SCE's non-electric and generation facilities

1. Drivers Impacted

The Smart Key Program (M1 and M2) will impact D1 (Security System Bypass/Breach) and D3 (Human/Process Failure) by helping prevent unauthorized access and providing greater accountability for the use of keys. Smart Keys can also detect unauthorized access attempts; such detection can alert SCE to concerning behavior and allow SCE to promptly investigate and take corrective measures as needed.

B. M3 – Enhanced Access Control

Enhanced Access Control will provide newer technology for upgrading our employee ID access badges and card readers. This technology should nearly eliminate the possibility that the badges and card readers can be manipulated to allow unauthorized access. The technology solution will include a new type of ID access badge with increased encryption capabilities to mitigate the potential of cloning. It will also provide a new type of card reader with special features that prevent manipulation to gain unauthorized access.

1. Drivers Impacted

The Enhanced Access Control mitigation (M3) will impact D1 (Security System Bypass/Breach) and D3 (Human/Process Failure) by helping prevent unauthorized access, and by providing greater security in the use of employee ID access badges.

In addition, M3 prevents and reduces D7 (Trespassing) events by ensuring that access permissions are only assigned to authorized users that have a business justification for possessing access. M3 also helps ensure that those access permissions cannot be altered through subversive methods. M3 can assist in detecting unauthorized access attempts; such detection can alert SCE to concerning behavior so that prompt action can be taken.

C. M4 - Enhanced Metal Theft Abatement

Enhanced Metal Theft Abatement is an accelerated version of the metal theft abatement security measures that occur pursuant to C1- Protection of Grid Operations. SCE will implement security measures for metal theft abatement (to mitigate copper theft) at more facilities each year. This measure increases the security at existing substations, where copper theft is ongoing and or increasing, by installing a high-security cut- and climb-resistant fence[15] and in some cases increasing the perimeter lighting. The high-security fencing has been found to be one of the single most effective mitigations in combatting fence cuts and breaching of this perimeter barrier. As a result, we have added this measure as a requirement for any new SCE substation.

1. Drivers Impacted

The Enhanced Metal Abatement mitigation (M4) will impact D1 (Security System Bypass/Breach) and D7 (Trespassing). It will accomplish this by adding significant capabilities to deter and delay any attempt to breach a barrier or trespass onto SCE property. The delay that is added by M4 can also assist in the detection and assessment capabilities of other controls and mitigations.
Because M4 should increase the amount of time it would take a suspect to breach a perimeter barrier, it

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[15] For instance, high-security fencing may include barbed wire topper, spikes, and other deterrent measures.

helps provide more time for other security measures to successfully detect and assess the threat. This would lead to a more immediate and effective response.

D. M5 – Advanced Surveillance Technology (AST)

This mitigation will deploy advanced surveillance technology at various facilities. Advanced Surveillance Technology is a term used to broadly describe several categories of technology. Such categories include autonomous and semi-autonomous, manually operated, static or fixed location, and wearable surveillance solutions. These technologies were originally developed for Military and Law Enforcement applications, but are now available for use in the Commercial Utility and Security Industries.

As technologies evolve and appropriate use cases are developed and refined, we anticipate that such technologies may in the future become more of a rule rather than an exception. Currently, SCE is planning a pilot program in 2023 to develop the appropriate use case(s) for several specific surveillance technologies. IT, T&D, and Cybersecurity teams will assist us in evaluating and confirming that these technologies will conform to all SCE policies and procedures.

Currently, SCE is evaluating Autonomous Security Robots (ASRs), Unmanned Ground Vehicles (UGVs), and UAS. Similar technologies are currently in use at other utilities, and initial reports have shown some success. Even though these technologies have already been in use, their applicability to a specific security mission or use case in our environment must still be tested and confirmed. Accordingly, there is still a degree of uncertainty surrounding any wider use of these technologies at this time.

UAS technology is already in use at SCE in a controlled environment for inspecting electrical assets with a Pilot in Charge to keep the UAS within their line of sight. Working with our Air Operations team, we are in the process of evaluating autonomous and semi-autonomous use of UAS using a Federal Aviation Administration (FAA) Beyond Visual Line-of-Sight (BVLOS) waiver. This will allow the pilot to control and observe the UAS without having to keep them within their line of sight, significantly increasing the effectiveness and efficiency of the UAS.

Security mitigations are based on their ability to deter, detect, delay, assess, and respond to security incidents. In evaluating various technologies, we consider which of these capabilities a technology might best address, and how these technologies may supplement, enhance, or supplant on-site personnel. Due to the varying operations that take place at our sites, some of these technologies may not provide an immediate value until the optimum use case is identified and developed.

1. Drivers Impacted

The Advanced Surveillance Technology (AST) mitigation (M5) that SCE is considering includes three distinct types of AST. They have the potential to impact D1 (Security System Bypass/Breach) and D2 (Security System Failure) by providing an additional layer of security technology. This additional layer enhances our ability to deter, detect and respond to an incident.

In addition, M5 can impact and reduce D7 (Trespassing), D6 (UAS Penetration), and D5 (Gunfire/Projectile Penetration) events by advancing our ability to deter, detect, delay, assess, and respond to these potential security incidents.

VI.

FOUNDATIONAL ACTIVITIES

SCE conducts security risk assessments of our electrical, non-electric and generation assets as part of controls C1 – C3 in a manner that would be considered foundational. The assessments in and of themselves do not directly reduce Physical Security risk; they identify vulnerabilities and the mitigations for those vulnerabilities. Inspections and internal audits are used to measure the effectiveness of the controls and mitigations. The costs associated with these activities are embedded in the cost forecasts for those respective controls.

VII.

PROPOSED PLAN

SCE evaluated the controls and mitigations in Sections IV and V, and we have developed a Proposed Plan that balances safety, affordability, and feasibility constraints. Please see Table VII-9 below, which displays the cost estimates and risk spend efficiencies (RSE) for the respective controls and mitigations.[16] The pre- and post-LoRE, CoRE and risk scores for the Proposed Plan are summarized

[16] Please refer to WP. Ch. 11 – Major Physical Security Financial Forecasts.

below by tranche in Table VII-10. We selected these controls and mitigations because they effectively and efficiently address the span of our overall security risks. This includes low-probability, high-impact events such as sabotage and workplace violence, and high-probability, low-impact events such as theft/vandalism and business disruption. The three main controls C1, C2, and C3 represent a combination of components that are tailored to the specific site's security needs.

Table VII-9
Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[17]

ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Protection of Grid Operations		$114.3	13.7
C2 - T3	Protection of Generation Capabilities		$10.9	1.1
C3 - T2	Protection of Major Business Functions		$49.3	42.1
C4 - T1	Asset Protection	$15.5		5.6
C4 - T2	Asset Protection	$5.6		9.2
C4 - T3	Asset Protection	$2.5		0.1
C5 - T1	Smart Key Program: Phases 1	$0.06	$0.6	3.0
M1 - T1	Smart Key Program: Phases 2		$2.4	10.7
M2 - T2	Smart Key Program: Phases 3		$2.2	12.5
M3 - T1	Enhanced Access Control		$6.3	143.2
M3 - T2	Enhanced Access Control		$0.3	189.7
M3 - T3	Enhanced Access Control		$0.7	2.7
Total		**$23.7**	**$186.9**	-

[17] Please refer to Major Physical Security RAMP Risk Model (excel file) and WP. Ch. 11 –Major Physical Security RAMP Financials.

Table VII-10
Pre- and Post-LoRE, CoRE and Risk Scores[18]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Major Physical Security Incident	256.2	0.003	0.71	211.4	0.003	0.63
T1 - Grid Operations	179.4	0.004	0.63	167.2	0.004	0.59
T2 - Major Businesss Functions	67.3	0.001	0.07	36.1	0.001	0.04
T3 - Generation Capabilities	9.5	0.000	0.001	8.0	0.000	0.0011

1. Overview

Prior to evaluating potential controls and mitigations, SCE Corporate Security developed (and continues to refine) an understanding of the overall security risks to our facilities. This includes current and future security risks that may have an adverse impact on our employees, visitors, facilities, assets, and our ability to provide reliable, safe, and affordable service to our customers. A critical piece of our proposed and alternative plans is found in part in our Control C4 (Asset Protection). This control provides both internal and external threat assessments and intelligence data collection and assessments that assist in identifying our overall risk.

SCE has designed controls that address unique risks facing the three facility types listed in C1 (Protection of Grid Operations), C2 (Protection of Generation Capabilities), and C3 (Protection of Major Business Functions). This is accomplished with site-specific and enterprise-wide physical security controls that we implement or refresh in a manner that addresses our overall risk. SCE's physical security controls and mitigations are developed based on overall security risk, and include the following:

- Examining best practices and lessons learned
- Analyzing incidents, risk, and industry trends
- Obtaining SME input from across the Company

18 Please refer to Major Physical Security RAMP Risk Model (excel file).

- Leveraging security risk assessments of Company facilities, performed by qualified SCE and Third-Party SMEs

The controls and mitigations in Table VII-9 along with security policies and procedures are used to form a layered approach in SCE's effort to deter, detect, delay, assess and respond to existing security risks. As discussed earlier, SCE faces various risks ranging from minor vandalism or theft to escalating incidents such as workplace violence and sabotage. We review and adjust our security programs based on changing threats and emergent priorities. These adjustments are made with careful consideration given to the costs to our customers and the authorized level of spending.

The strengthening and adjusting of our security programs is displayed in the aforementioned controls:

- C1 - Protection of Grid Operations
- C2 - Protection of Generation Capabilities
- C3 - Protection of Major Business Functions
- C4 - Asset Protection
- C5 - Smart Key Phase 1

SCE also proposes deploying the smart key technology from C5- Smart Key Phase 1 into the remaining SCE electrical facilities. This completion of the Smart Key rollout at our electrical facilities is represented by M1. We will also plan to roll out Smart Key technology at certain non-electric facilities pursuant to M2.

Due to the growing risks of identity theft by suspect(s) cloning employee access badges, we propose pursuing M3 – Enhanced Access Control. As discussed above, this mitigation provides a new and advanced type of badge and card reader that prevents unauthorized access.

2. <u>Execution Feasibility</u>

SCE evaluated the feasibility of executing the Proposed Plan based on current organizational capabilities, security technology, and ongoing work. The controls and mitigations chosen for the Proposed Plan either continue or enhance existing work. As such, SCE believes that the Proposed Plan can feasibly be executed.

3. **Affordability**

The Proposed Plan's total cost is less than that of Alternative Plan #1, and higher than Alternative Plan #2. To SCE, the Proposed Plan represents an optimal balance between controlling costs while appropriately addressing and mitigating physical security risks, in comparison to the other two plans. The Proposed Plan is forgoing M4- Enhanced Metal Theft Abatement and M5-Advanced Surveillance Technology (AST). The amount of risk reduction that would appear to be gained from employing M4 and M5 in Alternative Plan #1 does not seem to justify the level of spending needed at this time. SCE is accepting a certain level of risk by not employing the enhanced metal theft abatement security measures at more sites per year.

M5 involves new technology. The uncertainty surrounding certain aspects of the new technology led us to conclude that the investment in the technology is not warranted at this time. Please refer to the detailed explanation of M5 above for a full explanation of our current piloting and assessment efforts.

4. **Other Considerations**

Although M5 – AST was excluded from the Proposed Plan, we will still conduct initial pilots of advanced surveillance technology in order to determine its future viability. Depending upon the outcome of the pilot and the nature of future risks, some of the new technologies may ultimately be implemented to enhance, supplement, or even supplant some of the current controls and mitigations.

A second consideration involves the overall security risks at our dams, where we utilize C2 – Protection of Generation Capabilities controls. These C2 controls are utilized to address the criminal acts listed in this chapter's bowtie. Our bowtie does not include the uncontrolled release of water from our dams nor the catastrophic failure of a dam, which is addressed in the Dam Failure Chapter.

VIII.

ALTERNATIVE PLANS

A. Alternative Plan #1

As shown below in Table VIII-11, Alternative Plan #1 uses the three main controls C1, C2, and C3 at the respective types of facility that map to these controls. Alternative Plan #1 includes the same use of controls C4 and C5, and mitigations M1, M2, and M3, as the Proposed Plan. The difference is that this alternative includes the following mitigations: M4-Enhanced Metal Theft Abatement, and M5-Advanced Surveillance Technology (AST). The pre- and post-LoRE, CoRE and risk scores for Alternative Plan #1 are summarized below by tranche in Table VIII-11.

Table VIII-11
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[19]

ID - Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Protection of Grid Operations		$114.3	13.6
C2 - T3	Protection of Generation Capabilities		$10.9	1.1
C3 - T2	Protection of Major Business Functions		$49.3	42.1
C4 - T1	Asset Protection	$15.5		5.6
C4 - T2	Asset Protection	$5.6		9.2
C4 - T3	Asset Protection	$2.5		0.1
C5 - T1	Smart Key Program: Phase 1	$0.1	$0.6	3.0
M1 - T1	Smart Key Program: Phase 2	$0.3		10.7
M2 - T2	Smart Key Program: Phase 3	$0.4		12.4
M3 - T1	Enhanced Access Control		$6.3	142.3
M3 - T2	Enhanced Access Control		$0.3	189.4
M3 - T3	Enhanced Access Control		$0.7	2.7
M4 - T1	Enhanced Metal Theft Abatement		$24.2	3.6
M5 - T1	Advanced Surveillance Technology (AST)	$0.1		21.2
Total		**$24.6**	**$206.6**	**-**

[19] Please refer to Major Physical Security RAMP Risk Model (excel file) and WP. Ch. 11 –Major Physical Security RAMP Financials.

Table VIII-12
Pre- and Post- LoRE, CoRE and Risk Scores[20]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Major Physical Security Incident	254.9	0.003	0.70	209.8	0.003	0.62
T1 - Grid Operations	178.2	0.004	0.63	165.7	0.004	0.58
T2 - Major Businesss Functions	67.2	0.001	0.07	36.1	0.001	0.04
T3 - Generation Capabilities	9.5	0.000	0.001	8.0	0.000	0.001

1. Overview

Alternative Plan #1 provides for an increasing number of facilities upgraded in C1. This plan utilizes all the controls and mitigations available to address the continuing increase in criminal activity both in and around our facilities. This includes M4 – Enhanced Metal Theft Abatement to combat the growing trend of copper theft which is being exacerbated due to several economic factors.[21]

2. Execution Feasibility

Alternative Plan #1 provides an aggressive approach and schedule which may run the risk of not being fully executable within the given time constraints and in light of the significant dependencies on T&D and IT support for those projects. Although M5 – AST is currently being used on a limited basis by some of our peers and appears to have a good deal of potential, it is still relatively new to the Utility and Security Industries. The applicability to a specific security mission or use case in our environment must still be tested and confirmed. The technologies still have a degree of maturation to go, and appropriate use cases are not yet fully developed. Accordingly, the technologies may not provide an immediate value until the optimum use case is identified. The amount of time it will take to develop the appropriate use case or security mission for M5 may also add strain to an already aggressive schedule.

[20] Please refer to Major Physical Security RAMP Risk Model (excel file).

[21] https://spectrumnews1.com/ca/la-west/crime-safety/2021/11/11/copper-wiring-theft-rises-in-los-angeles.

3. Affordability

Alternative Plan #1 will take the greatest investment of time and capital dollars. As indicated above in Table VIII-11 and Table VIII-12, the incremental risk reduction for Alternative Plan #1 is minimal compared to the Proposed Plan, but Alternative Plan #1 costs approximately $20 million more per year. SCE believes that Alternative Plan #1 may currently be too aggressive. However, we will carefully reconsider it if security-based crimes against SCE go up, and/or the overall security risk significantly increases.

4. Other Considerations

Although M5 – AST components cannot currently perform all of the functions that a security officer can, they may perform much of the time-consuming work of patrolling designated areas. This would add a degree of ability to deter, detect, assess potential issues, and provide a limited-response capability. AST can allow the security officer to attend to the duties that AST are not able to perform at this time. Given the right AST in the appropriate circumstance, the AST could help us enhance, supplement, or even supplant certain current controls.

B. Alternative Plan #2

Alternative Plan #2 consists of the five controls (C1-C5) and M5 as identified below in Table VIII-13. It differs from both the Proposed Plan and Alternative Plan #1, in that Alternative Plan #2 only utilizes M5 - Advanced Surveillance Technology and foregoes the other new mitigations (M1, M2, M3, and M4). The expectation is that the accepted risks created from foregoing those mitigations will instead be mitigated by the new technology in M5. The pre- and post-LoRE, CoRE and risk scores for Alternative Plan #2 are summarized below by tranche in Table VIII-14.

Table VIII-13
Alternative Plan #2 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[22]

ID - Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	2025 Risk Spend Efficiency
C1 - T1	Protection of Grid Operations		$114.3	13.8
C2 - T3	Protection of Generation Capabilities		$10.9	1.1
C3 - T2	Protection of Major Business Functions		$49.3	42.7
C4 - T1	Asset Protection	$15.5		5.6
C4 - T2	Asset Protection	$5.6		9.4
C4 - T3	Asset Protection	$2.5		0.1
C5 - T1	Smart Key Program: Phases 1	$0.1	$0.6	3.0
M5 - T2	Advanced Surveillance Technology (AST)	$0.1		21.6
Total		**$23.9**	**$175.1**	**-**

Table VIII-14
Pre- and Post- LoRE, CoRE and Risk Scores[23]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	CoRE	Risk Score	LoRE	CoRE	Risk Score
Major Physical Security Incident	258.2	0.003	0.71	217.8	0.003	0.65
T1 - Grid Operations	180.6	0.004	0.64	172.3	0.004	0.61
T2 - Major Businesss Functions	68.1	0.001	0.07	37.2	0.001	0.04
T3 - Generation Capabilities	9.6	0.000	0.001	8.2	0.000	0.001

22 Please refer to Major Physical Security RAMP Risk Model (excel file) and WP. Ch. 11 –Major Physical Security RAMP Financials.

23 Please refer to Major Physical Security RAMP Risk Model (excel file).

1. Overview

Alternative Plan #2 utilizes the least number of mitigations of all the plans, incorporating only M5 – AST. By limiting this plan to this single mitigation, it may provide more time and capital to invest in researching, developing, and integrating the right M5 – AST into the most appropriate use case or security mission.

2. Execution Feasibility

Alternative Plan #2 would require the least investment of capital and internal resources, and therefore is feasible to execute. However, since M5 – AST is a new technology, the quantity of deployments and internal resources necessary to achieve the risk reduction that SCE estimated here is still uncertain and could vary. In a sense, Alternative Plan #2 has a relatively high degree of ambiguity with regard to ultimate success, because of the uncertainty surrounding the new technology solutions in M5 – AST. As discussed above, SCE is prudently piloting and assessing the new technologies. Until the results of those endeavors are known, the uncertainty factor is likely to remain.

3. Affordability

Alternative Plan #2 is the most affordable, requiring the least amount of spending currently. However, it may not provide the optimal overall risk spend efficiency or risk buy-down. One factor that may affect affordability is whether additional investments later prove necessary for M5 – AST to reach the needed level of performance and effectiveness. In other words, if we commit firmly to the new and rather uncertain technologies now, it is possible that we may have to spend additional sums later to "cement" the usefulness and effectiveness of the technology.

4. Other Considerations

Although M5 – AST components cannot currently perform all of the functions that a security officer can, they may perform much of the time-consuming work of patrolling designated areas. This would add a degree of the ability to deter, detect, assess potential issues, and provide a limited-response capability. AST can allow the security officer to attend to the duties that AST are not able to perform at this time. Given the right AST in the appropriate circumstance, the AST could help us enhance, supplement, or even supplant certain current controls.

IX.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

The first RAMP filing gave us an opportunity to level-set risks across the company and examine how physical security addresses certain risks and vulnerabilities. Quantifying risks and mitigations for the risk bowtie aided SCE in adjusting and refining our data collecting and reporting. We learned more about risk mitigation effectiveness and how we might quantify it when it is only applied to a subset of our portfolio of facilities.

Based on lessons learned in our last RAMP, we invested in new Insider Threat incident tracking technology. This technology modeled fields based on how we approached RAMP. The database contains fields that align with the risk bowtie components, drivers, outcomes, and outcome impacts. The more RAMP-aligned database allows SCE to provide more precise inputs for the RAMP probabilistic/predictive approach to identify potential threats and obtain a greater understanding of potential trends or areas of focus.

In addition to the fundamental physical security measures employed by SCE (e.g., fencing, lighting, security officers, etc.), the 2018 RAMP risk analysis helped confirm that the Company should diligently consider new mitigation options as technology improves and evolves (e.g., facial recognition software, personal identification technology, systems to identify gunshots and their direction of travel, etc.). In this RAMP, we incorporated a number of lessons learned from the last RAMP.

B. Data Collection and Availability

Since we implemented a new incident management system in 2020, our data collecting has improved. However, because the system was implemented in 2020, we started collecting data as of 2021, and are still making adjustments to the system to refine and improve the data collection. This causes some elements of the bowtie to have limited historical data using the new data collecting functionality. Among other items, this led to reliance to a degree on utility partner data for outcomes like Sabotage (O2) and Substations Attack (O4).

As our incident management system continues to provide quality data that gives a more comprehensive view of our physical security landscape and risk, we anticipate that we will have more advanced metrics and insights for the next RAMP filing. This would allow us to evaluate physical security risks more efficiently, and improve our quantification of tranches, risk drivers, risk events, risk outcomes, and associated consequences.

Further, while low-probability, high-impact incidents (e.g., sabotage, substations attack, and workplace violence) are fortunately limited, they do represent higher-priority physical security concerns because of the impact. Historical data related to these events is limited. This presents a challenge when populating inputs to probabilistic risk models, such as the one used for this RAMP risk analysis.

Accordingly, while the data we used in this RAMP report is the best information reasonably available, SCE will continue to examine ways to modify existing tracking systems and reports to better inform future risk analyses.

C. Performance Metrics

SCE continues to collaborate with other utilities, industry organizations, and government entities to identify metrics that can be used to measure our physical security efforts. SCE has tracking metrics and performance metrics. Tracking metrics primarily stem from external sources such as the annual FBI active shooter incident report and copper prices. Performance metrics are used to evaluate our performance with physical security efforts.

For tracking metrics, we evaluate reports and data from various sources because they help inform SCE regarding potential impending threats, evolving risks, and trends due to technology advancement, political factors, economic, and other factors. Some external metrics we track are:

- Annual FBI active shooter incidents[24] occurring at Commercial, Government, Residences, and Open Space types of locations. This aids us in evaluating workplace violence trends.

[24] *See* https://www.fbi.gov/file-repository/active-shooter-incidents-in-the-us-2020-070121.pdf/view.

- Copper price trends,[25] which have a positive correlation with the trends of copper theft incidents that SCE and peer utilities face.
- Annual summaries of Energy Disturbance Events, which show electrical disturbances and the types of events that caused them.

Internally, SCE utilizes a number of different performance metrics, including those discussed below in Table IX-15.

Table IX-15
Physical Security Metrics

Metric	Description
Cold-Start Response Time	Cold starts are requests for security guard coverage that require immediate attention. This metric tracks the percentage of times security officers respond to (planned & immediate) cold start requests within a 4-hour timeframe.
ESOC Significant Incident Report (ESIR)	Ensures timely notification to Corporate Security management and key stakeholders of significant security incidents. A notification generated by the Edison Security Operation Center within a 15 minute timeframe.
Security Project Milestone Adherence	Tracks project performance against scope, schedule, and cost.
Break/Fix Work Orders for Critical Facilities	Tracks the completion of break/fix notifications for critical facilities within the established period of time.
Crime Statistics	A monthly report that tracks the number of incidents by incident type (e.g., theft, trespassing, suspicious activity, and more) and compares totals to previous years.
Threats/Assaults Against Employees/Contractors	Tracks the number of incidents resulting in a threat or assault against an employee/contractor, and the associated drivers of the incidents (e.g., property access, power disconnection, and more).
Vandalism Crime Statistics	Tracks the number of vandalism incidents monthly, and the type of vandalism involved (e.g., break, tamper, and more).
Total Monthly Dispatches/Incident Reports	Tracks the number of events/incidents per month, and the cause (e.g., maintenance request, fire alarm, vandalism, and more).

25 *See* https://www.macrotrends.net/1476/copper-prices-historical-chart-data.

SCE continues to use and track performance metrics. With our newer data management system, as of 2021 we have greater amounts of data for use in our analysis in the following categories:

- Electrical service interruption: cumulative customer-minutes interruption (CMI) caused by physical security incidents
- Time of recovery from outages caused by physical security incidents
- Cost of recovery from outages caused by physical security incidents
- Number of incidents associated with copper theft by geographic area
- Number of false or nuisance alarms
- Number of malfunctions of security equipment

X.

ADDRESSING PARTY FEEDBACK

In reviewing SCE's 2018 RAMP report, the Commission's Safety Enforcement Division (SED) provided two recommendations regarding SCE's 2018 Major Physical Security RAMP Risk chapter. The Public Advocates Office (Cal Advocates) provided one additional recommendation.

SCE addressed these recommendations in our direct and supplemental Test Year 2021 GRC testimony.[26] We did not receive any feedback on our responses.

One of SED's recommendations noted that in our 2018 RAMP report, we indicated that our existing incident data management systems did not entirely support how SCE modeled the physical security risk, and that we would consider modifying or augmenting our current platform. As noted above in Section IX.B, since we implemented our new incident management system in 2020, our data collecting capabilities have improved.

[26] *See* A.19-08-013, Exhibit SCE-11 Supplemental Testimony on Risk Informed Strategy & Business Plan, p. 16.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Hydro Dam Failure

Chapter 12

Rosemead CA
May 13, 2022

Chapter 12: Hydro Dam Failure

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Chapter 12: Hydro Dam Failure

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I.

EXECUTIVE SUMMARY

A. Risk Overview

SCE operates a portfolio of 81 hydro dams which support 33 hydroelectric plants that provide a combined 1,153 MW of generating capacity.[1] The dams are typically located in remote mountainous areas and situated to capture high-elevation rain and snowmelt and the associated energy released as it flows downward. Most dams were constructed in the early 20th century, with the oldest dating to 1893 and the most recent dating to 1986. Approximately 3% of the electricity that SCE delivered to its customers in 2020 was generated by its hydro portfolio,[2] and this number fluctuates annually depending on hydrological conditions. As discussed below, SCE already performs a number of compliance tasks and controls that cost-effectively mitigate the risks associated with these hydroelectric plants, including the dams. SCE's Proposed Plan recommends continuing these controls and implementing limited relocation of inhabitable structures as an additional activity.

SCE approached its analysis of hydro dam risk by building on its existing Dam Safety Risk Assessment Program. SCE's Dam Safety Risk Assessment Program was initiated in 2008 and is modeled after hydro dam risk management best practices established by the U.S. Bureau of Reclamation. The approach is based on identifying the potential ways a specific dam could fail, known as Potential Failure Modes (PFMs), then evaluating the likelihood of occurrence and the consequence of each PFM. SCE's hydro risk analysis presented in this RAMP chapter builds on this work.

SCE defined the risk event (i.e., the center of the bowtie) as the Uncontrolled Rapid Release of Water (URRW). The scope is defined by dams with a hazard classification of "significant-hazard" or greater as designated by the California Department of Water Resources Division of Safety of Dams

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[1] SCE also operates two dams on Catalina Island that support its potable water supply and do not generate electricity.

[2] Edison International and Southern California Edison 2020 Annual Report, p. 145, available at https://www.edison.com/content/dam/eix/documents/investors/corporate-governance/2020-eix-sce-annual-report.pdf.

(DSOD) and/or the Federal Energy Regulatory Commission (FERC).[3] For convenience, SCE will refer to these facilities as high-hazard dams. SCE believes that this is an appropriate scope for the analysis, as the facilities have been identified by the relevant federal and/or state regulators as having the greatest potential to cause loss of human life.

This chapter discusses five drivers that could potentially lead to URRW: seismic events, flooding, failure under normal operations, physical attack and cyber attack. Risk outcomes are described in terms of three categories: the facility is inoperable and there is no significant inundation; there is inundation of an unpopulated area; there is inundation of populated and unpopulated areas. The overall likelihood of a catastrophic failure of one of SCE's 27 high- and significant-hazard dams is estimated as one failure every 238 years.

This chapter describes three compliance activities:[4]

- Hydro Operations (CM1): This includes monitoring and controlling reservoir levels and flows, routine observation and data collection by trained personnel, and regular testing of critical systems.
- Hydro Maintenance (CM2): This includes repairing minor/localized deterioration and maintaining operability of critical systems.
- External Inspections (CM3): Regular regulatory inspections are performed by the FERC and DSOD. Additionally, independent Consultant Safety Inspections are performed at five-year intervals for each dam in accordance with Chapter 18 of the Code of Federal Regulations (18 CFR) Part 12D.

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[3] Hazard classification is based on potential downstream impacts to life and property should the dam fail when operating with a full reservoir, as defined in the Federal Guidelines for Inundation Mapping of Flood Risk Associated with Dam Incidents and Failures (FEMA P-946, July 2013). A classification of "High" is given for a dam where one or more fatalities would be expected. DSOD created an "Extremely High" category in 2017 to identify dams that are expected to cause considerable loss of human life or result in an inundation area with a population of 1,000 persons or more). Five of SCE's 27 high-hazard dams are classified as Extremely High-Hazard.

[4] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

In addition to the compliance activities, this chapter describes one foundational activity:

- Dam Safety Program (F1): This program utilizes qualified engineers, supported by internal and external Subject Matter Experts, to help ensure compliance with laws and regulations and to identify and prioritize potential issues at dams.

The foundational activity supports six controls:[5]

- Seismic Retrofits (C1): Reinforcing dams to withstand seismic loading and/or making improvements to maintain seismic restrictions on reservoir levels.
- Dam Surface Protection (C2): Protecting upstream dam surfaces with geomembrane liner systems.[6]
- Spillway Remediation and Improvement (C3): Repairing and improving structures used to safely pass water flows from flooding events.[7]
- Low-Level Outlet Remediation and Improvement (C4): Repairing and improving systems used to draw down dam reservoir levels in a controlled manner.
- Seepage Mitigation (C5): Repairing or enhancing the structure and/or drainage systems of earthen dams to inhibit the initiation and progression of internal erosion.
- Instrumentation / Communication Improvements (C6): Improving instrumentation and communication systems used to detect conditions that may indicate dam failure.

Finally, this chapter describes three potential mitigations:[8]

- Proactively removing high-hazard dams to proactively reduce risks (M1).
- Relocating campgrounds or campsites within potential inundation zones (M2).

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[5] C = Control. This is an activity performed prior to or during 2022 to address the risk, and which may continue through the RAMP period. Controls are modeled this report and are addressed in Section IV.

[6] A geomembrane liner extends the life of a dam by reducing the degradation that can occur from water entering concrete pores and then freezing.

[7] A spillway is a structure that is used to make controlled releases of water flows from a dam into a downstream area, typically the riverbed of the dammed river itself. Water normally flows over a spillway only during flood periods.

[8] M = Mitigation. This is an activity commencing in 2023 or later to affect this risk. Mitigations are addressed in Section V of this chapter.

- Purchasing private residences within potential inundation zones (M3).

SCE has developed three risk mitigation plans for consideration:

- The Proposed Plan consists of continuing all current controls (C1 through C6).
- Alternative Plan #1 adds proactive removal of a small number of dams (M1) to the Proposed Plan.
- Alternative Plan #2 adds relocation of campgrounds and campsites (M2) and purchase of private residences (M3) to the Proposed Plan (but does not add M1).

B. Summary of Results

Table I-1 below summarizes the pre- and post-mitigation risk quantification scores for Hydro Dam Failure based on the Proposed Plan discussed below.[9]

Table I-1
Summary of Pre- and Post- LoRE and CoRE Risk Scores[10]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Hydro Dam Failure	0.0042	7.4	0.031	0.0041	5.3	0.022

II.

RISK ASSESSMENT

A. Risk Definition and Scope

Since 2008, SCE has maintained a Dam Safety Risk Assessment program, modeled after the "Risk Management – Best Practices and Risk Methodology," program established by the United States Bureau of Reclamation (USBR) in the mid-1990s.[11] The SCE Dam Safety Risk Assessment Program has

9 LoRE – likelihood of risk event. CoRE – consequence of risk event. Risk Score is the product of the LoRE and CoRE. For additional information on the risk modeling methodology, please refer to Chapter 2 – Risk Model and Methodology.

10 Please refer to Hydro Dam Failure Risk Model (excel).

11 The United States Bureau of Reclamation is a federal agency within the U.S. Department of the Interior. The Bureau of Reclamation oversees water resource management, specifically as it applies to the oversight and operation of the diversion, delivery, and storage projects that it has built throughout the western United States for irrigation, water supply, and attendant hydroelectric power generation.

been used to help understand, prioritize, and address potential dam safety issues across SCE's portfolio of dams.

The 27 high-hazard dams in scope for RAMP range in age from 36 to 116 years, with an average age of 93 years, and encompass a wide range of dam types, including:

- Earthfill – Balsam Meadow Dike, Bishop Intake 2 Dam, Lundy Lake Dam, Mammoth Pool Dam, Vermilion Valley Dam, Thompson Dam
- Rockfill – Balsam Meadow Dam, Hillside Dam, Portal Forebay Dam, Rhinedollar Dam, Sabrina Lake Dam, Saddlebag Dam, and Tioga Lake Dam.
- Concrete Gravity – Big Creek Dam 7, Huntington Lake Dam 1, Huntington Lake Dam 2, Huntington Lake Dam 3, Kern River 1 Diversion, and Shaver Lake Dam.
- Concrete Arch – Big Creek Dam 4, Big Creek Dam 5, Big Creek Dam 6, Rush Meadows Dam, and Tioga Lake Auxiliary Dam.
- Concrete Multiple-Arch – Agnew Lake Dam, Florence Lake Dam, and Gem Lake Dam.

1. Federal Dam Safety Risk Management Practices

The USBR is responsible for overseeing the management of hundreds of high-hazard dams and dikes[12] that comprise a significant portion of the water resources in the western U.S. The USBR developed principles and methods for assessing and managing risk to prioritize investments in dams and make more effective use of their resources.

The USBR framework has been updated, adopted, and modified by the USBR and other federal dam owners, such as the U.S. Army Corps of Engineers (USACE). It forms the basis of the recently released Federal Emergency Management Agency (FEMA) Guidelines for Dam Safety Risk Management[13] and the FERC guidelines for Risk Informed Decision Making (RIDM),[14] which will be referred to as the Federal risk guidelines. The descriptions set forth in this section relate to the federal

[12] A long wall or embankment built to prevent flooding.

[13] Federal Guidelines for Dam Safety Risk Management," Federal Emergency Management Agency, Report P-1025, January 2015.

[14] "Risk-Informed Decision Making (RIDM) Risk Guidelines for Dam Safety, Version 4.1," Federal Energy Regulatory Commission Division of Dam Safety and Inspections, March 2016.

government's established risk tolerance and mitigation framework for dam safety and may not be applicable to all aspects of utility risk mitigation activities and programs. Federal risk guidelines are based on two connected concepts:

- Tolerable Risk: A level of risk deemed acceptable by society in order that some particular benefit can be obtained, if that risk is being properly managed by the owner, and is reviewed and reduced as practicable; and,
- A risk has been appropriately reduced if it is As Low as Reasonably Practicable (ALARP).

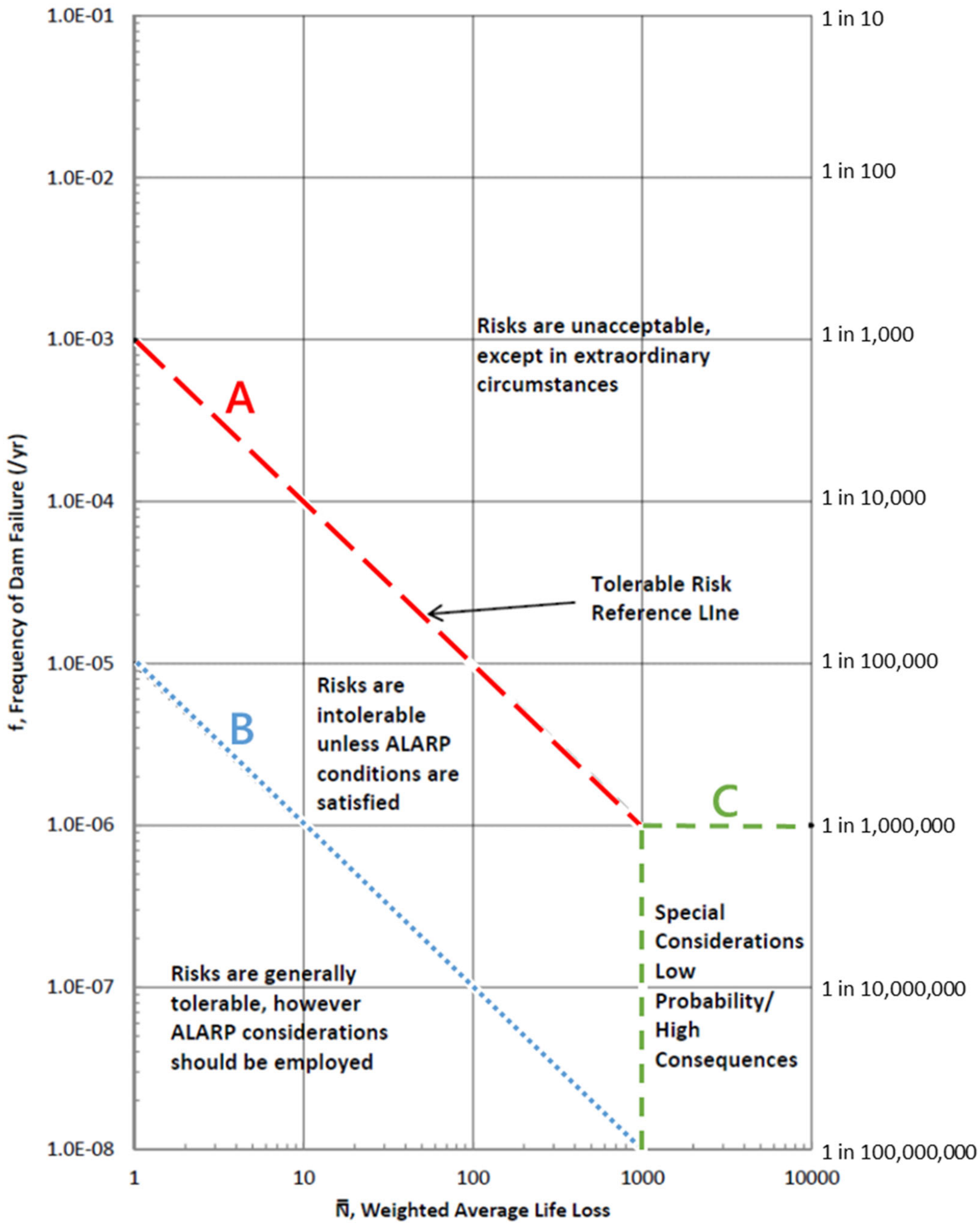
The federal guidelines employ an f-N chart for evaluating risk at individual dams. The chart included in the FERC RIDM Guidelines is shown in Figure II-1. This chart plots the annual frequency of occurrence for a PFM (f) against the expected loss of life should the PFM occur (N). Four "zones" on the f-N chart are identified by the guidelines:

- Risks are unacceptable except in extraordinary circumstances. This zone is defined by the region where average annual life loss is greater than one fatality per 1,000 years, as indicated by region above the reference line "A" in Figure II-1.
- ALARP region – Risks are intolerable unless ALARP is satisfied. This zone is defined as the region between reference lines "A" and "B" in Figure II-1.
- Risks are generally tolerable, but ALARP considerations should be employed. This zone is defined by the region where average annual life loss is less than one fatality per 100,000 years, indicated by region below the reference line "B" in Figure II-1.
- Special considerations – Risks have extremely high consequences but low probability; a thorough review of the benefits and risk of the project is needed to determine tolerability. This zone is defined as the region bounded by expected fatalities greater than 1,000, but annual probability less than 1 in 1,000,000. This is indicated by region enclosed by reference line "C" in Figure II-1.

The FERC RIDM guidelines list the following criteria to evaluate if ALARP is satisfied:

- The cost-effectiveness of potential incremental risk reduction measures.
- The level of risk in relation to the tolerable risk reference lines.
- Disproportionality of the proposed investment relative to the benefits.
- Good Practice evidenced by compliance with FERC Engineering Guidelines or other industry-recognized standard or good practice.
- Societal concerns as revealed by consultation with the community and other stakeholders.
- Other factors, including duration of the risk, availability of risk reduction options, potential for creation of new risks, adequacy of the PFMA, consideration of standards, and benchmarking with other dam owners.

Figure II-1
f-N Chart from FERC Risk Informed Decision-Making Guidelines



Two types of risk analyses are used under FERC RIDM guidelines:

- Semi-Quantitative Risk Analyses (SQRA), where the likelihood and consequences for each PFM are classified into broad bins by teams of SMEs. The primary purpose of

SQRA is to determine which PFMs are of most concern for a dam or portfolio of dams and require additional study and evaluation.

- Quantitative Risk Analyses (QRA), where additional field investigations, analyses and study are used to develop quantitative estimates of the probability of failure and the consequences of failure for the most critical PFM(s) of a dam or portfolio of dams. The primary purpose of QRA is to inform decision-making around dam safety investments, and typically involves analyzing both the risk under existing conditions and the risk under a set of proposed mitigations.

The FERC RIDM Guidelines, as well as those used by the USBR and USACE, emphasize that risk analyses are not intended to be used as the sole criteria for judging the safety of a dam. Rather, they are a component of a "Dam Safety Case" that presents the rationale for a proposed course of action to manage risk.

FERC has recently amended its regulations governing the safety of hydroelectric projects to require SQRAs for all high-hazard dams.[15] Implementation of this requirement will begin in 2023 with the goal of completing risk assessments for all FERC-regulated dams by 2038.

2. State Dam Safety Risk Management

The California DSOD does not yet have formal guidelines or criteria regarding dam safety risk. However, in a March 16, 2020 letter to all owners of dams under its jurisdiction, DSOD announced its plans to "develop, implement, and integrate Risk Informed Decision Making (RIDM) into its Dam Safety Program," with the goal of publishing amended protocols for inspection and re-evaluation of dams by 2024.[16]

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15 "Final Rule, 18 CFR Part 12: Safety of Water Power Projects and Project Works." Federal Energy Regulatory Commission, Docket No. RM20-9-000, Order No. 888, December 16, 2021.

16 "Notice of Intent to Update - Dam Safety Inspection and Reevaluation Protocols to Incorporate Risk Informed Decision Making into the California Dam Safety Program," March 16, 2020. https://water.ca.gov/-/media/DWR-Website/Web-Pages/Programs/All-Programs/Division-of-Safety-of-Dams/Files/Publications/Notice-of-Intent-to-Update-Inspection-and-Reevaluation-Protocols.pdf.

3. SCE Dam Safety Risk Management

SCE applies the principles outlined in the federal guidelines to managing risks identified for its dams. The defined inventory of dam risks is the set of PFMs developed through the FERC-required Potential Failure Modes Analysis (PFMA) process.[17] SCE has assigned likelihood and consequence categories to each of these PFMs through SQRA workshops involving SCE personnel, outside experts and regulators. The current categorization of dam risks resulting from these SQRAs is summarized in Figure II-2, which shows how the PFMs are distributed across the likelihood and consequence categories. These results have been used by SCE to identify and prioritize dam safety projects and serve as the foundation of the risk model presented in the chapter.

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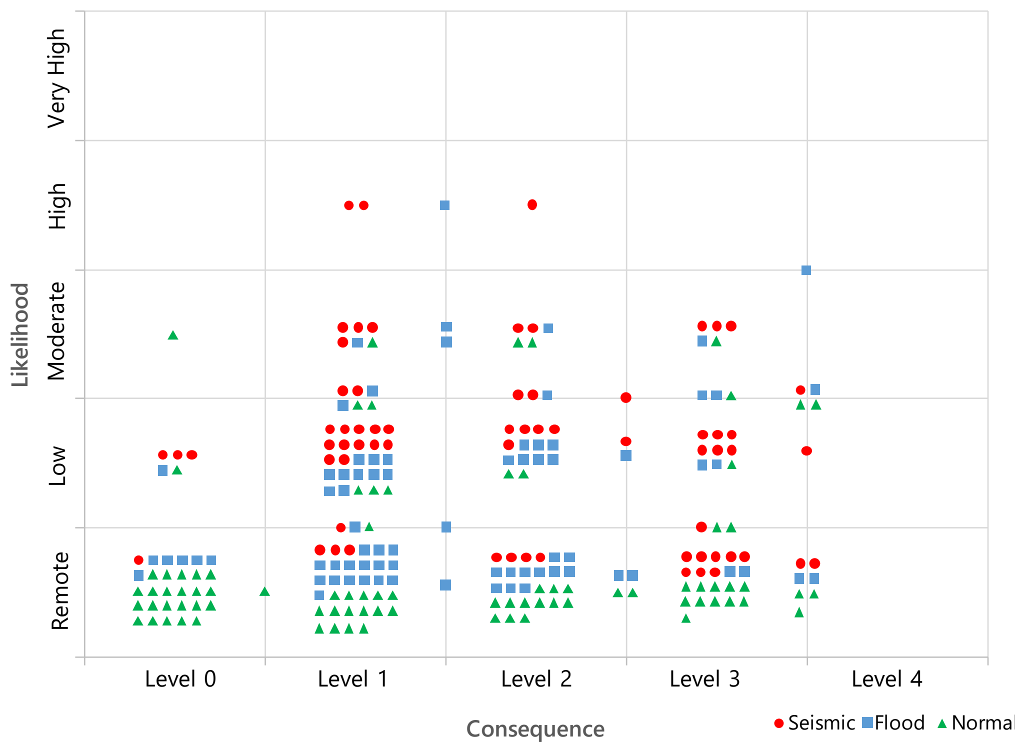
[17] Starting in 2002, FERC has required owners of high-hazard dams to perform PFMAs and update them every five years.

Figure II-2
Risk Categorization of Potential Failure Modes for High Hazard Dams due to Non-Intentional Causes



In 2020, FERC issued draft guidelines for conducting SQRA, which were subsequently finalized in 2021.[18] SCE conducted one pilot SQRA in 2021 using the draft guidelines and anticipates completing another pilot using the final guidelines in 2022.

SCE completed and submitted one QRA report under the FERC RIDM Guidelines (the first such report submitted in the country). FERC review of SCE's QRA report submission is expected to be completed in 2022.

The Hydro Dam Failure risk analysis scope is summarized in Table II-2.

[18] "Level 2 Risk Analysis." FERC Engineering Guidelines for the Evaluation of Hydropower Projects, Chapter 18, December 2021.

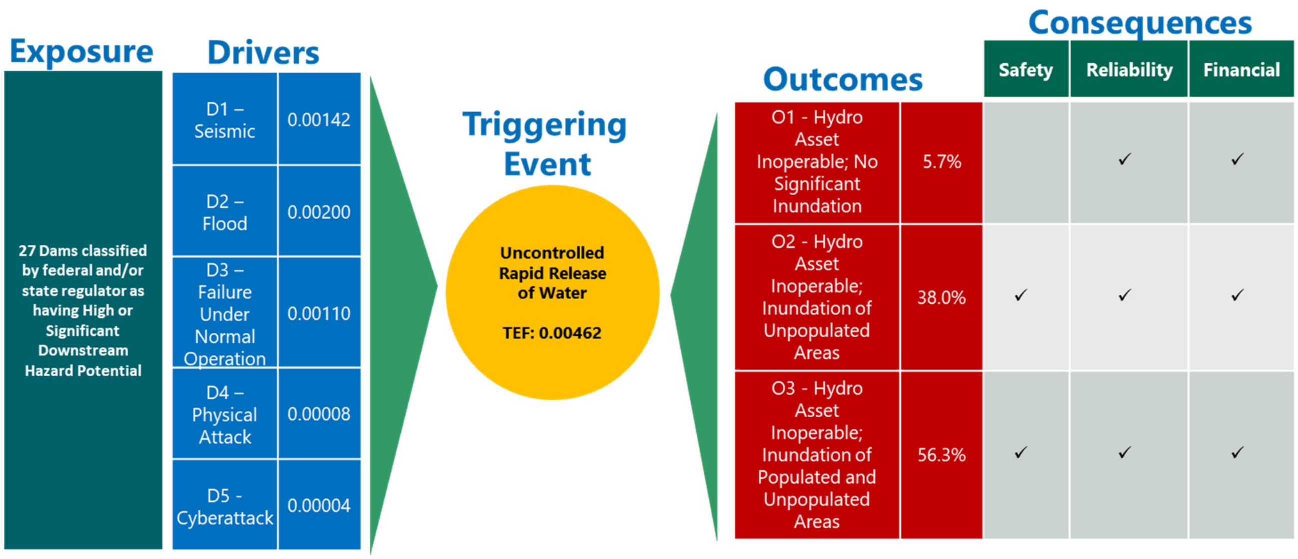
Table II-2
Hydro Dam Failure Risk Analysis Scope

In Scope	• URRW due to failure of a significant- or high-hazard dam caused by natural hazards (e.g., flood, earthquake), deterioration or incorrect operation. • URRW due to intentional malicious acts performed by an SCE Employee of Contractor. • URRW due to an adversary gaining control of a high-hazard dam through physical access. • URRW due to an adversary gaining control or a high-hazard dam through cyber access.
Out of Scope	• Dams classified as low-hazard

B. Risk Bowtie

SCE used the bowtie methodology, as shown in Figure II-3, to develop a quantitative risk model specific to SCE's high-hazard dams. This model uses a combination of SCE-specific data, industry data, and guidance from SCE dam safety experts, to gain a better understanding of the risk drivers and consequences for a dam failure. The bowtie presents the risk drivers, outcomes, and consequences; additional details can be found in the sections below.

Figure II-3
Hydro Asset Safety Risk Bowtie[19]



C. <u>Drivers</u>

In this 2022 RAMP report, SCE identified five drivers (Earthquake; Flood; Failure under Normal Operations, Physical Attack, and Cyber Attack) that could lead to the uncontrolled rapid release of water. In the 2018 RAMP, dam failure drivers for Physical Attack and Cyber Attack were incorporated into the RAMP chapters for Physical Security and Cybersecurity.

The risk model uses the following sources for estimating driver frequency:[20]

- The SCE Dam Safety Risk Register, which tracks the most current assessment of the likelihood and consequence of every identified PFM for each dam. A total of 236 PFMs are associated with the 27 SCE dams evaluated for RAMP. Each PFM is mapped to one of the five drivers mapped to natural and/or unintentional dam failure (seismic, flood, failure under normal operations, physical security, and cybersecurity); the estimated frequencies of all PFMs within a driver category are summed to produce the total driver frequency.

[19] Please refer to WP Ch. 12 – Baseline and Risk Inputs.

[20] Please refer to WP Ch. 12 – Baseline and Risk Inputs.

- Statistical analysis of database of worldwide large dam failures through May 2018 compiled by the International Commission on Large Dams (ICOLD).[21] The number of failures mapped to each driver was adjusted to the age and type of construction of the dams in the SCE portfolio.
- Information on attacks and threats against dams compiled by the US Department of Homeland Security.

1. <u>D1 – Earthquake</u>

Earthquakes must be taken into account for dams located in California. Several SCE dams, particularly those on the eastern slopes of the Sierra Nevada Mountains, are located near known faults. For all dam sites, the possibility of activity on unidentified faults cannot be ruled out. The ground motions caused by earthquakes can negatively impact dams in a variety of ways:

- The material of embankment dams or their foundations may settle or slide such that the crest of the dam falls below the reservoir level. This allows water to spill over and erode the downstream material, leading to a complete breach. This nearly occurred at Lower Van Norman Dam when the 1971 San Fernando earthquake resulted in the loss of the upper 30 feet of the dam. The reservoir was only half-full at the time; had it been at full capacity, the resulting flood would likely have killed tens of thousands of people in the San Fernando Valley.
- Concrete dams may suffer significant cracking and loss of strength, compromising their ability to hold back the reservoir water. Movement of the rock foundations and abutments can also trigger a loss of support for the structure, leading to dam failure. While there are no recorded cases of concrete dams failing as a result of an earthquake, several have been damaged, such as Koyna Dam (1967) and Pacoima Dam (1971, 1994).

[21] "Statistical Analysis of Dam Failures," International Commission of Large Dams Bulletin 188, 2019.

The frequency of this driver was estimated by averaging two sources:

- The combined annual frequency of PFMs related to seismic events in the SCE Dam Safety Risk Register. These PFMs were assessed in facilitated Risk Assessment Workshops that included SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD.[22] Risk Assessment Workshop participants considered all available information, including probabilistic seismic hazard evaluations for each dam site and seismic stability analyses.
- Historic failure rate computed from the ICOLD database of large dam failures associated with seismic loading, adjusting for the age and composition of SCE dams.

The average of the annual frequencies for these two sources for the SCE portfolio of dams is 0.00142 (approximately 1 in 700). This driver accounts for 31.0% of the overall frequency of triggering events.

2. D2 – Flood

Flooding typically occurs because of heavy precipitation or snowmelt. Weather-related flooding events typically are easier to predict in the short term. SCE manages such events by using reservoir storage, passing water through spillways and outlets, and coordinating high-flow events with upstream and downstream dam operators. However, if water inflows exceed the capacity of the system, then the stability of the dam may be threatened.

- Water that goes over (i.e., overtops) an embankment dam will likely begin to erode and carry away the downstream material, which can progress to a complete breach. This occurred in the 1889 failure of South Fork Dam, which claimed 2,209 lives in one of the worst dam failure disasters in U.S. history.[23]

[22] Please refer to WP Ch. 12. – Baseline and Risk Inputs.

[23] "Case Study: South Fork Dam (Pennsylvania, 1889)" Lessons Learned from Dam Incidents and Failures, Association of State Dam Safety Officials. http://damfailures.org/case-study/south-fork-dam-pennsylvania-1889/.

- The rock foundations and abutments of concrete dams can also be vulnerable to erosion from extreme flood flows, leading to a loss of support for the dam and failure (Austin Dam 1911, Malpasset Dam 1959).

The frequency of this driver was estimated by averaging two sources:

- The combined annual frequency of PFMs related to flood events in the SCE Dam Safety Risk Register. As indicated above, assessing PFMs related to flood events occurred in facilitated Risk Assessment Workshops. These workshops included SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD.[24] Risk Assessment Workshop participants considered all available information, including evaluating the probable maximum flood for each dam, and evaluating the stability of the dam under the resulting reservoir levels.
- Historical failure rate computed from the ICOLD database of large dam failures associated with flood loading, adjusting for the age and composition of SCE dams.

The average of the annual frequencies for these two sources for the SCE portfolio of dams is 0.00195 (approximately 1 in 500). This driver accounts for 42.6% of the overall frequency of triggering events.

3. D3 – Failure under Normal Operations

Dam failures have also been observed to occur in the absence of extreme loading events such as flood and seismic events. These types of failures are most common in dams with design or construction flaws, and generally occur within the first few years of operation. Some examples are the failures of St. Francis Dam (1928), Teton Dam (1976) and Camara Dam (2004).[25] Though less common, dams that have functioned safely for decades may also fail due to degradation.

- Embankment dams can experience "piping" failures, where seepage through the dam begins to carry away the material. This creates an expanded cavity that could

[24] Please refer to WP Ch. 12 – Baseline and Risk Inputs.

[25] The owners of these dams were the City of Los Angeles, The United States Bureau of Reclamation (USBR), and the nation of Brazil, respectively.

collapse, lowering the crest of the dam and allowing water to run over the top, thereby eroding the downstream material and progressing into a full breach.

- Concrete dams may experience a loss of strength due to "freeze-thaw" cycling[26] that eventually compromises the ability of the structure to retain the reservoir.
- Dam subsystems such as outlet pipes or spillway gates may also deteriorate over time, leading to failure and uncontrolled releases, such as the Folsom Dam (1995).
- Finally, failure to follow Station Orders and other operating procedures could potentially lead to a dangerous discharge of water. FERC determined that this led to a drowning death at Varick Dam (2010).[27]

The frequency of this driver was estimated by averaging two sources:

- The combined annual frequency of PFMs related to events occurring during normal operations in the SCE Dam Safety Risk Register. As indicated above, assessment of these PFMs occurred in facilitated Risk Assessment Workshops[28] where participants considered all available information, including design documents, surveillance and monitoring data, and previous repairs and improvements.
- Historical failure rate computed from the ICOLD database of large dam failures occurring during normal conditions, adjusting for the age and composition of SCE dams.

The average of the annual frequencies for these two sources for the SCE portfolio of dams is 0.00109 (approximately 1 in 900). This driver accounts for 23.8% of the overall frequency of triggering events.

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26 A process where water permeates tiny cavities in concrete and freezes. Since ice occupies approximately 9% more volume than the same amount of liquid water, this stresses the concrete and may result in cracking and expansion of the cavities. When thawing occurs, liquid water fills the expanded cavity and the process repeats.

27 "Erie Boulevard Hydroelectric, L.P., Order Approving Stipulation and Consent Agreement," Federal Energy Regulatory Commission, Docket No. IN13-12-000. January 15, 2014.

28 Please refer to WP Ch. 12 – Baseline and Risk Inputs.

4. **D4 – Physical Attack**

Dam failures could also be caused by a deliberate attack on the physical structure of the dam or key components by an outside party or SCE employee or contractor. This can include:

- Use of explosives on the structure or within the dam reservoir
- Use of heavy construction equipment to breach an embankment dam
- Deliberate mis-operation of water-releasing features

The frequency of failures was estimated based on two sources: 1) historical failures recorded in the ICOLD database classified as occurring due to "Hostile Human Action;" and 2) extrapolation based on the United Stated Department of Homeland Security memo detailing attacks on dams from 2001-2011.[29]

The average of the annual frequencies for these two sources for the SCE portfolio of dams is 0.00008 (approximately 1 in 13,000). This driver accounts for 1.6% of the overall frequency of triggering events.

5. **D5 – Cyber Attack**

If an adversary were to successfully breach SCE's cyber protection and gain control of remotely-operable, water-releasing features of the dam, that adversary could potentially cause a hazardous inundation.

The frequency of failures was estimated based on the single known successful instance of a compromise of a dam system's controls, as documented in a US Department of Homeland Security memo.[30] The estimated annual frequency of occurrence for the SCE portfolio of dams is 0.00004 (approximately 1 in 23,000). This driver accounts for 1.0% of the overall frequency of triggering events.

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[29] "Worldwide Attacks Against Dams, A Historical Threat Resource for Owners and Operators", US Department of Homeland Security, 2012. https://damfailures.org/wp-content/uploads/2019/04/Worldwide-Attacks-Against-Dams.pdf.

[30] "Dams Sector Landscape", US Department of Homeland Security Cyber and Infrastructure Security Agency, August 2019. https://damsafety-prod.s3.amazonaws.com/s3fs-public/files/6.%20Dams%20Sector%20Landscape.pdf.

D. Triggering Event

SCE defines the Triggering Event as the URRW from a Hydro Significant- or High-Hazard Dam. This definition has been used by SCE's Dam & Public Safety department since 2008 and is consistent with the Federal Guidelines for Dam Safety Glossary of Terms,[31] which defines dam failure as "characterized by the sudden, rapid, and uncontrolled release of impounded water." While any type of damage or malfunction that prevents a hydroelectric high-hazard dam from functioning as intended can be considered a failure, SCE has identified uncontrolled, rapidly occurring water discharges as the greatest potential threat to the safety of the downstream population.[32]

E. Outcomes and Consequences

SCE has identified three potential outcomes should URRW occur. Figure II-3 above depicts the estimated likelihood of the three outcomes. Each of the 229 PFMs evaluated with natural causes in the SCE portfolio is uniquely mapped to one of the three outcomes based on severity as shown in Figure II-4.

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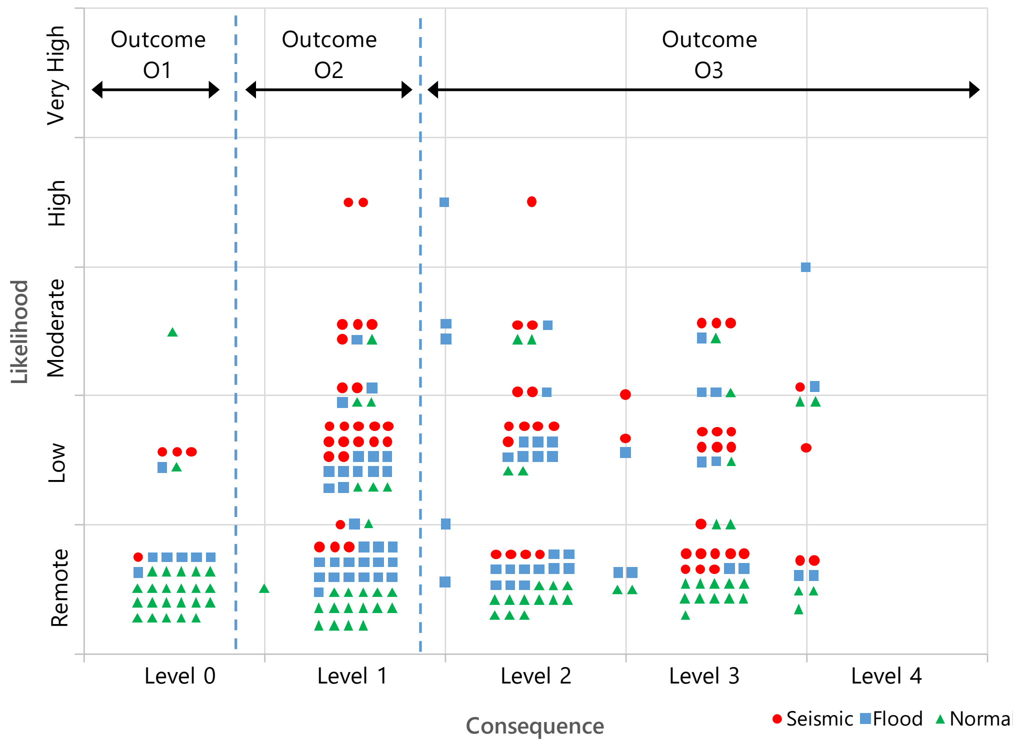
[31] "Federal Guidelines for Dam Safety Glossary of Terms." Federal Emergency Management Agency, Report 148, April 2004.

[32] Controlled discharges, on the other hand, afford an opportunity for planning and communication efforts to mitigate the impacts, while a slowly occurring discharge allows for evacuating potentially impacted areas. Hydro Asset failures resulting in URRW have been the focus of SCE's previous risk assessment activities for dams, and will remain the focus in this RAMP chapter.

Figure II-4
Mapping of Potential Failure Modes With Non-Intentional Causes to Outcomes



1. O1 – Hydro Facility Inoperable; No Significant Inundation

This outcome occurs when a dam failure causes URRW, but it does not result in significant downstream inundation (i.e., the water is contained within the normal banks of the stream). If the dam is directly connected to a hydroelectric plant, that plant will be inoperable. If the dam is a storage reservoir, that storage capacity will be unavailable. Hydro facilities will remain unavailable until the damage is repaired. Approval from federal and/or state regulators will also be required to resume operation.

Of the 229 PFMs associated with non-intentional causes, 35 have consequences that are mapped to this outcome. The probabilities of failure due to hostile action for one dam is mapped to this outcome, based on the expected consequences of failure under normal operating conditions. The total frequency of these sources represents approximately 6% of the overall Triggering Event frequency.[33]

2. O2 – Hydro Facility Inoperable; Inundation of Unpopulated Area

This outcome occurs when a dam failure causes URRW, resulting in loss of operability of the associated hydro assets, and the inundation of unpopulated downstream areas. For the dams considered in RAMP, these would generally be forested areas that people do not regularly occupy or travel.

Of the 229 PFMs associated with non-intentional causes, 78 have consequences that are mapped to this outcome. The probabilities of failure due to hostile action for one dam is mapped to this outcome, based on the expected consequences of a failure under normal operating conditions.
The probabilities of failure due to hostile action for eight dams are mapped to this outcome, based on the expected consequences of failure under normal operating conditions. The total frequency of these sources represents approximately 38% of the overall Triggering Event frequency.

Safety Consequences are associated with potential impacts to recreationists traveling in remote areas. Reliability consequences are associated with localized areas served by hydroelectric plants that are periodically "islanded" from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power, as well as damage caused by inundation.

3. O3 – Hydro Facility Inoperable; Inundation of Unpopulated and Populated Area(s)

The worst-case outcome considered is a dam failure resulting in URRW that inundates a populated area. This impact is in addition to the inundation of unpopulated areas and loss of operability for the associated hydro facilities.

Of the 229 PFMs associated with non-intentional causes, 116 have consequences that are mapped to this outcome. The probabilities of failure due to hostile action for one dam is mapped to this outcome, based on the expected consequences of a failure under normal operating conditions.
The probabilities of failure due to hostile action for 18 dams are mapped to this outcome, based on the

[33] Please refer to WP Ch. 12 – Baseline and Risk Inputs.

expected consequences of failure under normal operating conditions. The total frequency of these sources represents approximately 56% of the overall Triggering Event frequency.

Safety consequences, including serious injuries and fatalities are associated with pedestrians, occupied vehicles, or occupied structures inundated by the released water. Reliability consequences are associated with disruption of service to localized areas due to direct damage to the electrical system, as well as periodic disruptions to areas served by hydroelectric plants that are periodically "islanded" from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power, as well as damage caused by inundation.

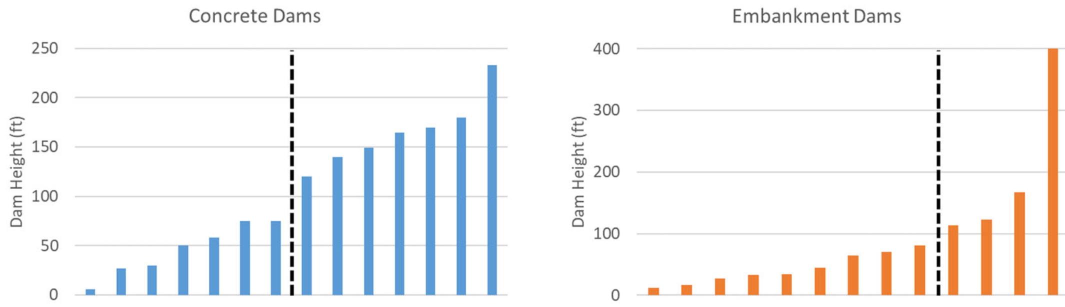
F. Tranches

SCE dams have been divided into four tranches based on composition (e.g., concrete or earth/rock) and height. Specifically:

- Embankment dams less than 100 feet in height
- Concrete dams less than 100 feet in height
- Embankment dams greater than 100 feet in height
- Concrete dams greater than 100 feet in height

Dam composition is correlated with the relative frequency of the drivers (e.g., earthfill/rockfill embankments are more vulnerable to flood than concrete structures). Dam height is correlated with consequences, since larger dams generally impound more water and could impact a larger area in the event of a failure. Figure II-5 shows concrete and embankment dams sorted by height. The largest difference in heights for concrete dams is between the 7th and 8th tallest dams at 75 feet and 120 feet, respectively. For embankment dams the largest gap (other than the difference between the tallest and second-tallest dams) is between the 4th and 5th tallest dams at 114 feet and 81 feet, respectively. Therefore, 100 feet was identified as a reasonable height limit for defining the tranches.

Figure II-5
Height of Significant- and High-Hazard Dams



G. Related Factors

For purposes of this discussion, SCE defines related factors as factors that are not directly included in the risk modeling but can impact the driver frequency and the likelihood of certain outcomes. Based on current data collecting abilities, we are not able to quantitively show how they impact the risk bowtie components, but we explain qualitatively below:

- **Climate Change** – Climate Change does not significantly impact dam failure risks in the period considered by this RAMP. Potential impacts of climate change on flood risk further in the future are discussed and evaluated in SCE's Climate Adaptation and Vulnerability Assessment (CAVA) report. In this RAMP Report, the CAVA is addressed in Appendix B – Climate Change.
- **Physical Security** – Measures to prevent unauthorized access of SCE facilities are applied at dams and other hydropower facilities. However, they are not modeled in this chapter, as these activities are a small percentage of overall physical security spending and are not considered to substantially reduce the occurrence dam failures below the baseline rate.
- **Cyber Security** – Measures to prevent unauthorized access of SCE cyber assets are applied at dams and other hydropower facilities. However, they are not modeled in this chapter, as these activities are a small percentage of overall cyber security spending and are not considered to substantially reduce the occurrence dam failures below the baseline rate.

III.

COMPLIANCE

SCE describes three compliance activities (CM1-CM3), which are required to adhere to laws and regulations governing dam safety. Electing not to perform this work for a dam in a timeframe acceptable to FERC would likely result in orders to perform immediate corrective actions, such as the order issued in 2020 to drain the reservoir for Anderson Dam.[34] In extreme cases, the associated FERC license for the project may be revoked, as occurred for Edenville Dam in 2018.[35] Similarly, DSOD has the authority to impose reservoir restrictions and to revoke the certificate of approval required to operate a dam in California if it determines that there is a danger to life and property. Consequently, SCE's "baseline" risk considered these compliance activities and accordingly did not risk-score the compliance activities.

A. CM1 – Hydro Operations

SCE is required to operate its hydroelectric facilities in a safe manner. This includes maintaining situational awareness of the system through inspections and instrumentation, regulating the water flows and reservoir levels, and operating hydroelectric generating units.

SCE's trained hydro operations and maintenance personnel routinely observe our dams. These personnel are stationed in the watersheds where the SCE dams are located. During regular visits to the dams, these personnel perform visual observations of the dams, collect monitoring data, and report any changed or unusual conditions that could potentially impact dam safety or SCE's ability to operate the facility's spillways and outlet structures in a safe manner.

Operations personnel regulate water flows to help ensure efficient use of water and maximum generation from resources. These activities include the following:

- Regularly inspecting the reservoir facilities;
- Making gate changes to regulate water releases;

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[34] "Anderson Dam." Federal Energy Regulatory Commission https://www.ferc.gov/industries-data/hydropower/dam-safety-and-inspections/anderson-dam.

[35] "Boyce Hydro Power, LLC; Order Proposing Revocation of License." Federal Energy Regulatory Commission, Document 83 FR 8253. February 26, 2018.

- Cleaning the grids at flowline entrances; and
- Removing debris from in and around flowlines, flumes, penstocks, and other typical Hydro waterways.

Station Orders are created to help ensure that controlled releases are performed safely. All station personnel are required to follow station orders.

Dispatching work includes directing all O&M activities associated with the powerhouses in the Big Creek and Bishop Creek/Mono Basin areas, and the associated transmission and distribution facilities. The dispatching function is critical to successfully operating these facilities. The Big Creek Control center contains all the supervisory control equipment for the Big Creek facilities, while the Bishop Control substation contains all the supervisory control equipment for the Bishop Creek, Mono Basin, and Kern River facilities.

Unmanned East End and Kaweah facilities have alarms that notify the Bishop Control substation of unusual events through a dial-up system. This 24-hour surveillance of the operating equipment from a central point helps maintain system integrity and operational effectiveness.

B. <u>CM2 – Hydro Maintenance</u>

SCE is required to maintain its hydroelectric facilities, including dams, in a safe operating condition.

This activity includes planning and scheduling equipment maintenance activities at reservoirs, dams, canals, flumes, and other appurtenant hydraulic structures to comply with state and federal regulatory requirements. The activity also encompasses condition analysis, engineering recommendations, and mandated reports. SCE is required to test, inspect, and report to make sure that the physical condition of facilities and equipment is safe for continued operation, through efforts such as:

- Technical inspection
- Electrical and mechanical engineering
- Civil, structural, and geotechnical engineering
- Construction management and cost engineering

- Performance engineering and testing
- Supervising repairs at Hydro production facilities, structures, and equipment
- Providing engineering support needed to perform tests and inspections, and prepare reports
- Applying concrete gunite[36] to repair aged and weather-damaged surfaces of dams and intakes
- Repacking joints and repairing leaks in steel penstock pipes and flumes
- Maintaining water-diverting equipment such as valves and spillways
- Repairing wood-frame structures appurtenant to Hydro facilities, such as flowline trestles, snow shelter survival cabins, gatehouses, and hydraulic equipment shelters.

C. CM3 – External Inspections

SCE's dams are routinely inspected and evaluated by external parties. Inspections are performed by:

1. FERC Division of Dam Safety and Inspections (FERC D2SI). As the federal agency responsible for the safety of hydroelectric projects located on federal lands, FERC D2SI inspects all SCE high-hazard dams annually. SCE personnel accompany the inspector(s) to help ensure the inspector can safely access and observe all relevant features of the dams. The SCE personnel also respond to any questions the inspector may have. Following the inspection, FERC issues a letter documenting the inspection findings, which may include recommending specific repairs, actions or studies. SCE is required by FERC to file a plan and provide a schedule to address these recommendations.
2. California Department of Water Resources, DSOD. As the state agency responsible for maintaining the safety of dams in California, DSOD inspects all SCE high-hazard dams annually. SCE personnel accompany the inspector(s) to help ensure they can safely access and observe all relevant features of the dams. The SCE personnel also respond to any questions the inspectors may have. Following the inspection, DSOD issues a report that may include recommendations for specific repairs, actions or studies.

[36] "Gunite" is a mixture of cement, sand, and water applied through a high-pressure hose. It produces a dense, hard layer of concrete, and can be used for lining tunnels or making structural repairs.

3. Part 12 Independent Consultants. Since 1965, FERC has required, under 18 CFR Part 12, that owners of dams designated as high-hazard, or that meet specified criteria for size, must be evaluated by an Independent Consultant every five years. FERC reviews the credentials and approves every Independent Consultant. The Independent Consultant physically inspects the condition of the dam, and comprehensively evaluates the operating procedures, supporting analyses, and other documentation. The Independent Consultant also reviews the Potential Failure Modes Analysis to re-evaluate existing PFMs and identify whether any new PFMs are needed. The Independent Consultant provides written findings to FERC. This includes stating whether the dam is safe for continued operation, and listing recommendations for repairs, actions or studies. SCE must file a plan and provide a schedule to FERC to address these recommendations.
4. Board of Consultants. FERC has the authority to require that a dam owner retain a Board of Consultants to regularly inspect a specific dam. Currently, only Vermilion Valley Dam (SCE's largest embankment dam) has an established Board of Consultants, who perform annual inspections and issue a report on their findings. While not required by FERC, the design engineers of Vermillion Valley Dam have emphasized that the continued safe operation of the dam depends upon the performance (as assessed by the Board of Consultants) of the dam's complicated drainage system.

IV.

CONTROLS

SCE has existing programs and processes in place that serve to reduce the likelihood of the risk materializing, or the impact level of a risk event should it occur.

Hydro Capital Maintenance Refurbishment and/or Replacement activities (C1-C6) are controls consisting of capital investments necessary for maintaining dam infrastructure and equipment. Infrastructure work includes projects such as dam improvements needed to address identified areas of concern. SCE considered work forecast to occur in 2022-2028 for the 27 high-hazard dams and evaluated the work's impact on mitigating the RAMP drivers, outcomes, and consequences.[37,38] The hydro dam control activities are summarized in Table IV-3 and discussed in more detail in the sections that follow. As this analysis was performed using capital project forecasts developed in mid-2021, SCE's 2025 GRC final funding request may contain additional projects in this category or reflect updated estimates on project cost and schedule, which will be appropriately documented therein.

Table IV-3
List of Hydro Dam Controls

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed or Alternative Plan(s)?
C1	Seismic Retrofit	D1	-	-	Yes	All
C2	Dam Surface Protection	D3	-	-	Yes	All
C3	Spillway Remediation and Improvement	D2	-	-	Yes	All
C4	Low Level Outlet Improvements	-	O2, O3	Safety and Financial	Yes	All
C5	Seepage Mitigation	D3			Yes	All
C6	Instrumentation / Communication Enhancements		O3	Safety	Yes	All

A. <u>C1 – Seismic Retrofit</u>

SCE retrofits its dams to increase their capability to withstand seismic loads. SCE performs this activity when it identifies deterioration of the structure, a deficiency in the original design, or an increase in the estimated seismic loads that the dam must withstand.

This work may include rehabilitating and/or replacing concrete, re-compacting and/or replacing embankment materials, installing post-tensioned anchors, and constructing reinforcing elements such as

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[37] The process used to forecast Hydro capital expenditures begins with staff identifying equipment needing capital replacement or refurbishment, safety concerns or regulatory compliance issues requiring plant additions or modifications (which includes Hydro relicensing), and other site modifications or improvements needed to address operations or maintenance needs.

[38] Please refer to WP. Ch. 12 – Baseline and Risk Inputs.

steel braces, concrete buttresses or earthen berms. Some of SCE's dams currently operate under restricted intended reservoir levels, due to potential vulnerability to seismic loading. At these dams, seismic retrofit work may also include making modifications to comply with the restrictions. Specifically, the work can include lowering the spillway elevation or improving the capacity and/or reliability of the low level outlet works (further discussed in below).

1. Drivers Impacted

This control impacts D1 (Earthquake) by reducing the occurrence of failures due to seismic loading. Please note that this control provides benefit not by reducing the frequency of actual seismic events (which, of course, are outside of SCE's control), but by reducing the Triggered Event Frequency number that springs from seismic events.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

B. C2 – Dam Surface Protection

SCE performs repairs and installs protection systems to the surfaces (both upstream and downstream) to reduce seepage through its dams. In embankment dams, seepage may transport fine soil particles out the dam, leading to the formation of voids that can compromise the dam's stability. Seeping can also weaken concrete dams by leaching (dissolution of concrete components) or "freeze-thaw" cycling.

This work can include the installation of waterproof barriers, such as geomembrane liner systems, application of sealants to concrete surfaces or the repair/replacement of concrete or shotcrete surfaces.

1. Drivers Impacted

This control impacts D3 (Failure under Normal Operations) by reducing the leakage through the dam, reducing deterioration at concrete structures, and inhibiting flows through embankment dams that could contribute to internal erosion failures.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

C. C3 – Spillway Remediation and Improvement

SCE repairs and improves the spillways at its dams. This work can include refurbishing deteriorated concrete, installing or improving protective measures (such as water-stops between concrete slabs or drains beneath spillway chutes), rehabilitating or improving spillway gate structures, expanding the spillway or armoring embankment dams to allow them to withstand overtopping of water.

1. Drivers Impacted

This control impacts D2 (Flood) by enhancing the capacity and reliability of dams to safely pass inflows from extreme floods.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

D. C4 – Low Level Outlet (LLO) Improvements

SCE performs LLO repair and improvements for dams. LLOs are systems that can be used to lower the reservoir level of a dam in a controlled manner. In addition to managing water levels during normal operations, LLOs can be used in an emergency to empty the reservoir to prevent or reduce the consequences of dam failure. DSOD has specific requirements regarding the capacity and testing of these systems. As a response to the failure of the Oroville dam in 2017, a requirement to annually operate LLO systems was added to state law, so functioning LLOs are also a legal requirement. Additionally, the systems may be used to meet requirements for minimum instream flow requirements specified as required by the FERC license for the project.

This work can include repairing or replacing valves, gates, gate operators, or constructing a replacement LLO system if the original systems is too costly or difficult to repair, or if additional capacity is required to meet operational or regulatory requirements.

1. Drivers Impacted

This control is not considered to impact drivers for this risk. Although it is possible that low-level outlets could be utilized to drain a reservoir to prevent a slow-developing failure (occurring over multiple days), there was not sufficient information to credibly model how often this might occur.

2. Outcomes and Consequences Impacted

This control impacts the Safety and Financial consequences of O2 (Hydro Facility Inoperable; Inundation of Unpopulated Areas) and O3 (Hydro Facility Inoperable; Inundation of Unpopulated and Populated Areas) by allowing SCE to partially drain reservoirs in a controlled fashion prior to dam failure to reduce the volume of water in the resulting URRW.

E. C5 – Seepage Mitigation

SCE performs seepage mitigations to reduce the likelihood of initiation and progression of internal erosion in embankment dams. This work can include constructing or rehabilitating drains to reduce seepage, constructing filters to mitigate erosion, and filling sinkholes or joints in the foundation on the upstream side of the dam. In some cases, reducing seepage from the dam could negatively impact downstream wetlands areas. As a result, SCE may be required under the Clean Water Act to perform compensatory mitigation, which could include restoring a previously existing wetland, enhancing/preserving an existing wetland, or establishing a new wetland.[39] This requirement can be met by purchasing credits from an approved "mitigation bank" as proposed by the US Army Corps of Engineers for their Sacramento River Seepage Mitigation Project.[40] Depending on the circumstances, this requirement could represent a significant portion of the costs.

1. Drivers Impacted

This control impacts Driver D3 (Failure under Normal Operations) by reducing the probability that identified PFMs related to internal erosion will progress to failure.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

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[39] "Compensatory Mitigation for Losses of Aquatic Resources; Final Rule." Department of Defense 33 CFR Part 325 and 332, Environmental Protection Agency 40 CFR Part 230. April 10, 2008, *available at* https://www.epa.gov/sites/production/files/2015-03/documents/40_cfr_part_230.pdf.

[40] "Sacramento River Seepage Mitigation Project", US Army Corps of Engineers website, *available at* http://www.spk.usace.army.mil/Media/Regulatory-Public-Notices/Article/1531315/spk-2018-00139-sacramento-river-seepage-mitigation-project-yolo-county-ca/.

F. C6 – Instrumentation and Communication Improvements

Many SCE dams are in remote locations and do not have permanent on-site dam tenders.[41] However, SCE uses instrumentation to monitor the condition of these dams at centralized Hydro Control Rooms, where an operator is present 24 hours a day. SCE performs work to maintain and improve the capability and reliability of dam instrumentation. This work can consist of repairing, replacing, or installing instruments. Such instruments include reservoir level indicators, flow measurement devices, piezometers[42] and surveillance cameras. The work also encompasses repairing and/or improving the systems that transmit the instrument readings via fiber, radio, and/or satellite to Hydro Control Rooms. This work also includes repairing, replacing and installing sirens that can be used to alert the public in the event of a release, whether occurring from normal operations or from a dam failure.

1. Drivers Impacted

This control is not considered to impact drivers for this risk. It is possible that detecting potential failure conditions could allow SCE to intervene to prevent a dam failure from occurring. However, after reasonable inquiry there was insufficient information to credibly model how often this might occur.

2. Outcomes and Consequences Impacted

This control impacts the Safety consequences of O3 (Hydro Facility Inoperable; Inundation of Unpopulated and Populated Areas).

V.

MITIGATIONS

In addition to the controls describe above, SCE has identified additional risk mitigations that could be performed over the 2022-2028 period as shown below in Table V-4.

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[41] A "dam tender" is the person responsible for daily or routinely operating and maintaining a dam and its appurtenant structures. The dam tender often resides at or near the dam.

[42] Generally speaking, a "piezometer" is an instrument for measuring the pressure of a liquid or gas, or something related to pressure (such as the compressibility of liquid). Piezometers are often placed in boreholes to monitor the pressure or depth of groundwater.

Table V-4
List of Hydro Dam Failure Mitigations

ID	Control Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Included in 2018 RAMP?	Included in Proposed or Alternative Plan(s)?
M1	Accelerated Dam Removal	D1, D2, D3, D4, D5	-	-	Alternative Plan #1	Alternative Plan #1
M2	Relocation of Campgrounds	-	O3	Safety	Alternative Plan #2	Alternative Plan #2
M3	Purchase/Relocation of Inhabitable Structures	-	O3	Safety	Alternative Plan #2	Proposed
M4	Dam Divesture	D1, D2, D3, D4, D5	-	-	No	Alternative Plan #2

A. M1 –Accelerated Dam Removal

While it requires a complex, lengthy, and costly undertaking, the risk of failure for a dam can be reduced to zero if the dam is removed. Currently, when SCE is considering whether to make significant investment in a given dam, decommissioning is considered as an alternative. SCE could alter its strategy to consider proactively decommissioning dams to reduce risk. Dam removal is an extensive process that involves: (a) developing a detailed construction plan for safely removing the asset; (b) obtaining all necessary regulatory approvals; (c) performing the work while taking appropriate measures to protect the environment and appropriately dispose of the removed material; (d) remediating the area to a "natural" state in consultation with the appropriate state and federal agencies (when required by law or regulation); and (e) mitigating the impact of dam removal on the downstream community in consultation with public and private stakeholders.

SCE was authorized to begin collecting revenue for future dam decommissioning in the 2021 GRC Track 1 Final Decision.[43] Currently, one project is in the process of being decommissioned (a former high-hazard canal that has been inoperable since 2013 and is now classified as low-hazard). Decommissioning of two high-hazard dams may take place after 2030. This mitigation considers accelerating the timeline of decommissioning.

[43] D.21-08-036, p. 640.

1. Drivers Impacted

This mitigation impacts D1 (Earthquake), D2 (Flood), D3 (Failure under Normal Operation), D4 (Physical Attack) and D5 (Cyberattack) by eliminating all PFMs associated with the removed dams.

2. Outcomes and Consequences Impacted

This mitigation is not considered to impact outcomes and consequences.

B. M2 – Relocation of Campgrounds

When many of SCE dams were constructed, the downstream areas were relatively undeveloped. The encroachment of inhabited areas into potential inundation zones is an issue many dam owners face. At many SCE dams, a large portion of the population at risk in a potential dam failure are located in campgrounds. Relocating these sites could potentially reduce risk.

SCE may be able to accomplish this mitigation by working with the U.S. Forest Service to relocate campsites or campgrounds located within inundation zones. While this work has not been performed before by SCE, there are examples of campgrounds relocated out of flood plains that may serve as a precedent.[44]

1. Drivers Impacted

This mitigation is not considered to impact drivers.

2. Outcomes and Consequences Impacted

This mitigation would reduce the Safety consequences for O3 (Hydro Facility Inoperable; Inundation of Populated and Unpopulated Areas), as it effectively reduces the populated area that could potentially be inundated by a dam failure.

C. M3 – Purchase/Relocation of Inhabitable Structures

Similar to relocating campgrounds, purchasing or relocating inhabitable structures in the potential inundation zone could reduce the consequences of a dam failure. Canadian utility BC Hydro

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[44] "Tucannon Lakes and Floodplain Reconfiguration," Washington Department of Fish & Wildlife, *available at* https://wdfw.wa.gov/lands/wildlife_areas/wt_wooten/floodplain_management/TucannonWootenFactSheet_2015_April.pdf.

recently used this strategy to reduce risk for a dam identified as vulnerable to failure if a large earthquake occurs.[45],[46] SCE is currently in negotiations to implement this mitigation for one dam.

1. **Drivers Impacted**

This mitigation is not considered to impact drivers.

2. **Outcomes and Consequences Impacted**

This mitigation would reduce the Safety consequences for O3 (Hydro Facility Inoperable; Inundation of Populated and Unpopulated Areas). The mitigation would reduce the population that could be inundated by a dam failure.

D. **M4 – Dam Divestiture**

SCE may choose to divest portions of its hydropower portfolio by transferring the associated FERC license to another interested party. In these cases, responsibility for managing the risks associated with the dam are also transferred. PG&E has initiated this process for several of its hydropower projects and SCE has recently announced its intentions to divest some of its smaller hydropower projects (all classified as low hazard). This transfer process must be approved by FERC, who considers, among other factors, the ability of the new owner to maintain the safety of the project. It should be noted in some cases the current owner may actually need to pay money to the receiving party, because the project ends up having a negative value.

1. **Drivers Impacted**

This mitigation impacts D1 (Earthquake), D2 (Flood), D3 (Failure under Normal Operation), D4 (Physical Attack) and D5 (Cyberattack) by transferring responsibility for managing the risks associated with the divested dam to another entity.

2. **Outcomes and Consequences Impacted**

This mitigation is not considered to impact outcomes and consequences.

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45 "BC Hydro Buys Out Properties Below Jordan River Dam." CBC News, May 18, 2016, *available at* https://www.cbc.ca/news/canada/british-columbia/b-c-hydro-jordan-river-1.3585351.

46 Seismic Hazard at Jordan River", BC Hydro website, *available at* https://www.bchydro.com/energy-in-bc/operations/dam-safety/seismic-hazards/jordan-river-options.html.

VI.

FOUNDATIONAL ACTIVITIES

A. F1 – Dam Safety Program

1. Program Overview

SCE maintains a dam safety program to help ensure that its hydroelectric facilities operate safely.

SCE's Dam Safety Program (DSP) aims to protect life, property, and the environment by making sure that all dams are designed, constructed, operated, and maintained as safely and as effectively as reasonably possible. To accomplish this, SCE must continually inspect, evaluate, and document the design, construction, operation, maintenance, rehabilitation, and emergency preparedness of SCE and key downstream stakeholders. SCE also needs to archive documents concerning the inspections and histories of dams, and the training records for personnel who inspect, evaluate, operate, and maintain them.

These activities are governed by SCE's Owner's Dam Safety Program (ODSP). The ODSP is a FERC-required document that established roles and responsibilities regarding dam safety at SCE, up to and including the President and CEO. SCE's Dam & Public Safety (D&PS) Group, led by the Chief Dam Safety Engineer (CDSE) is responsible for overseeing the operations and strategies that help ensure that SCE's hydro generating facilities operate safely and reliably. Responsibilities include:

- Conducting inspections of dams and supporting inspections by FERC, DSOD and the Part 12D Independent Consultants;
- Evaluating field observations and data collected under the Surveillance and Monitoring Program for each dam;
- Identifying and prioritizing key issues for dams through the Risk Assessment Program, and helping ensure that all data and records pertaining to dam safety are appropriately maintained;
- Providing technical leadership and support to help ensure compliance with the FERC and the California DSOD regulations; and

- Helping ensure that Emergency Action Plans (EAPs) for high-hazard dams are supported by appropriate inundation mapping[47] and analysis of potential failure scenarios. Also, assisting in EAP training and exercises.

The expectations of the Dam Safety Program are prescribed by FERC, which requires Owners to undergo an external audit of their ODSP every five years. In addition, SCE employs an independent panel of experts titled the Dam Safety Advisory Board (DSAB) to review the Dam Safety Program on an annual basis and to advise on dam safety issues as requested. Lastly, for complicated dam safety issues, a Board of Consultants may be convened to opine and advise on issues and help guide SCE's actions to address those issues.

2. Rationale for Inclusion as Foundational

The activities of the Dam Safety Program are important to identifying and prioritizing risk to dams and supporting the execution of the controls and mitigations to reduce risk. However, these activities were judged to only reduce risk through the implementation of the identified controls and mitigations and were thus considered to be more appropriately included as foundational rather than as an independent control.

3. RSE Cost Allocation Treatment

The Dam Safety Program supports the identification, planning and execution of all the projects composing the controls. Consequently, the costs from F1 (which are ~$1.23M per year) are distributed across all Controls identified in Table IV-3, proportional to the estimated project cost as a fraction of total spending.

VII.

PROPOSED PLAN

SCE has evaluated the mitigations and controls in Sections IV and V and developed a Proposed Plan of risk-reduction activities to pursue as described below in Table VII-5. Forecasts will be updated

[47] "Inundation mapping" generally refers to a map that delineates the area that would be flooded by a particular flood event. It includes the ground surfaces downstream of a dam, showing the probable encroachment by water released because of: (a) failure of a dam, or (b) abnormal flood flows released through a dam's spillway and/or other appurtenant pathways for the water.

as part of the 2025 GRC filing. The pre- and post- LoRE, CoRE and risk scores for the Proposed Plan is summarized by tranche below in Table VII-6.[48]

Table VII-5
Proposed Plan (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[49]

ID - Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	Average Annual Foundational Costs Allocated	2025 Risk Spend Efficiency
C1	Seismic Retrofit	-	$0.00	$0.00	
C2	Dam Surface Protection	-	$0.00	$0.00	
C3 - T3	Spillway Remediation and Improvement	-	$5.20	$0.17	
C3 - T4	Spillway Remediation and Improvement	-	$5.00	$0.16	104.0
C4 - T1	Low Level Outlet Improvements	-	$2.64	$0.09	0.04
C4 -T2	Low Level Outlet Improvements	-	$2.98	$0.10	
C4 -T3	Low Level Outlet Improvements	-	$1.12	$0.04	
C4 -T4	Low Level Outlet Improvements	-	$4.08	$0.54	
C5 - T3	Seepage Mitigation	-	$1.00	$0.03	
C5 - T3	Seepage Mitigation	-	$4.50	$0.10	155.3
C6 - T3	Instrumentation / Communication Enhancements	-	$0.10	$0.00	1.0
C6 - T4	Instrumentation / Communication Enhancements	-	$0.05	$0.00	230.3
M3	Purchase/Relocation of Inhabitable Structures	-	$0.00	$0.00	
	Total	**$0.00**	**$26.67**	**$1.23**	

[48] Please refer to Hydro Dam Failure RAMP Risk Model (excel file) and WP. Ch. 12 –Hydro Dam Failure RAMP Financials.

[49] Although no capital spending is identified in 2025-2028 for C1, C2 and M3, these measures are included because spending is expected to occur in 2022-2024, and has been modeled as part of the baseline risk calculation. The 2025 risk spend efficiencies are not shown for certain Controls, because risk reduction benefits are not realized until project completion, and no projects in these categories are currently forecast to close in 2025.

Table VII-6
Summary of Pre- and Post- LoRE and CoRE Risk Scores[50]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Hydro Dam Failure	0.0042	7.4	0.031	0.0041	5.3	0.022
T1 - Concrete Dams < 100 ft High	0.0012	1.4	0.002	0.0012	1.3	0.002
T2 - Embankment Dams < 100 ft High	0.0015	3.6	0.006	0.0015	3.6	0.006
T3 - Concrete Dams > 100 ft High	0.0010	6.3	0.006	0.0009	5.7	0.005
T4 - Embankment Dams > 100 ft High	0.0006	32.9	0.018	0.0004	20.6	0.009

A. Overview

SCE's Proposed Plan includes capital maintenance and refurbishment projects including C1 (Seismic Retrofit), C2 (Dam Surface Protection), C3 (Spillway Remediation and Improvement), C4 (Low Level Outlet Improvements), C5 (Seepage Mitigation), and C6 (Instrumentation and Communication Improvements) and M3 (Purchase/Relocation of Inhabitable Structures). This work is a continuation of SCE's efforts to responsibly manage the risk associated with its high-hazard dams. It should be noted that there is no identified spend for C1 and C2 in the 2025-2028 period, but these measures are included because work is planned in 2022-2024.

B. Execution Feasibility

Although SCE expects to be able to execute the amount of work contemplated in this Proposed Plan, executing on the proposed capital projects can be impacted by the need to obtain approvals, given the large number of agencies involved. A project may require approvals from FERC, DSOD, U.S. Forest Service, California Department of Fish & Wildlife, California Water Quality Board, regional water quality control boards, California State Historic Preservation Officer, local air quality districts, and/or others. Some of these approvers will have competing requirements and interests.

Another factor that impacts the execution schedule of the projects is the short construction window for many dams. Most construction projects for dams at higher elevations cannot begin until June or July, due to snow conditions. The end of the working season for many sites is typically early

50 Please refer to Hydro Dam Failure RAMP Risk Model (excel file).

November, but early winter storms can shut down projects as early as October. This can cause project schedules to be extended by one to two years.

SCE has also observed that in years of high wildfire activity, the availability of helicopters to support construction in remote locations is significantly impacted, which in some cases has required SCE to delay or extend projects. While SCE has attempted to mitigate this risk by performing work prior to the start of fire season, in many high-altitude locations this is not possible due to weather and snowpack conditions.

C. Affordability

SCE believes the proposed controls are an appropriate investment in maintaining the safety of its dams, many of which have been in operation since the early 20th century. While the baseline risk is the lowest among the risks scored for RAMP, the proposed portfolio is estimated to reduce this risk by approximately 29%. This figure is incremental to the risk already reduced through required compliance activities.

This Proposed Plan, especially C3 (Spillway Remediation and Improvement) and C5 (Seepage Mitigation), will address the top risks within SCE's portfolio of dams identified through this RAMP analysis, as well as SCE's existing Dam Safety Risk Assessment Program. While the deployment of surveillance cameras under C6 in the previous RAMP was considered to be highly effective in reducing risk, most of the risk reduction benefit was achieved in projects completed through 2021. There are still some opportunities to improve the instrumentation, communication and power at some dams, which provides operational benefits as well as enhanced situational awareness and greater ability to evacuate downstream areas in the event of a dam failure.

Some of the proposed controls have relatively low RSEs but are still recommended as they provide other benefits. C4 (Low Level Outlet Improvements) enhances SCEs ability to manage water for normal operation and maintenance activities and in some cases is needed to meet instream flow requirements specified by project licenses.

D. Other Considerations

Projects that require draining or substantially lowering the reservoir levels can face challenges with competing water management needs. In high-runoff years, it may be difficult to safely release or store the water elsewhere. In low-water years, draining a reservoir may negatively impact SCE's ability to meet its obligations to other water users and meet minimum flows required to protect aquatic species and riparian habitats.

VIII.

ALTERNATIVE PLANS

SCE has evaluated the mitigations and controls in Sections IV and V and has developed two alternative plans for reducing risk, as summarized below. The pre- and post- LoRE, CoRE and risk scores for the proposed plan is summarized by tranche below in Table VIII-8.[51]

A. Alternative Plan #1

SCE developed Alternative Plan #1 as shown in Table VIII-7.

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[51] Please refer to Hydro Dam Failure RAMP Risk Model (excel file) and WP. Ch. 12 –Hydro Dam Failure RAMP Financials.

Table VIII-7
Alternative Plan #1 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[52]

ID - Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	Average Annual Foundational Costs Allocated	2025 Risk Spend Efficiency
C1	Seismic Retrofit	-	$0.00	$0.00	
C2	Dam Surface Protection	-	$0.00	$0.00	
C3 - T3	Spillway Remediation and Improvement	-	$5.20	$0.09	
C3 - T4	Spillway Remediation and Improvement	-	$5.00	$0.11	104.5
C4 - T1	Low Level Outlet Improvements	-	$2.64	$0.06	0.04
C4 -T2	Low Level Outlet Improvements	-	$2.98	$0.05	
C4 -T3	Low Level Outlet Improvements	-	$1.12	$0.02	
C4 -T4	Low Level Outlet Improvements	-	$4.08	$0.07	
C5 - T3	Seepage Mitigation	-	$1.00	$0.02	
C5 - T3	Seepage Mitigation	-	$4.50	$0.06	156.9
C6 - T3	Instrumentation / Communication Enhancements	-	$0.10	$0.00	1.0
C6 - T4	Instrumentation / Communication Enhancements	-	$0.05	$0.00	233.2
M1 - T1	Accelerated Dam Removal	-	$20.00	$0.75	
M3	Purchase/Relocation of Inhabitable Structures	-	$0.00	$0.00	
	Total	**$0.00**	**$46.67**	**$1.23**	

[52] Although no capital spending is identified in 2025-2028 for C1, C2 and M3, these measures are included because spending is expected to occur in 2022-2024, and has been modeled as part of the baseline risk calculation. The 2025 RSEs are not shown for certain Controls because risk-reduction benefits are not realized until project completion, and no projects in these categories are currently forecast to close in 2025.

Table VIII-8
Summary of Pre- and Post- LoRE and CoRE Risk Scores[53]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Hydro Dam Failure	0.0042	7.4	0.031	0.0039	5.5	0.021
T1 - Concrete Dams < 100 ft High	0.0012	1.4	0.002	0.0010	1.5	0.001
T2 - Embankment Dams < 100 ft High	0.0015	3.6	0.006	0.0015	3.6	0.006
T3 - Concrete Dams > 100 ft High	0.0010	6.3	0.006	0.0009	5.7	0.005
T4 - Embankment Dams > 100 ft High	0.0006	32.9	0.018	0.0004	20.6	0.009

1. Overview

SCE's Alternative Plan #1 includes all the measures in the Proposed Plan: C1 (Seismic Retrofit), C2 (Dam Surface Protection), C3 (Spillway Remediation and Improvement), C4 (Low Level Outlet Improvements), C5 (Seepage Mitigation), and C6 (Instrumentation and Communication Improvements) and M3 (Purchase/Relocation of Inhabitable Structures). It also includes M1 (Accelerated Dam Removal).

2. Execution Feasibility

SCE is currently planning to partially remove two dams that are currently under restriction due to seismic concerns, likely beginning in 2030. This work requires agreement from FERC, the US Forest Service and other state and local stakeholders. SCE is currently working to obtain this agreement through the relicensing process for the associated hydropower project. This work could potentially be accelerated into the 2025-2028 RAMP window, but would require approval from FERC, the US Forest Service and other local stakeholders. SCE is currently working to obtain this agreement through the relicensing process for the hydropower project. While some parties might be supportive of accelerating the work, it is uncertain whether this agreement could be reached under current conditions.

3. Affordability

While SCE believes that removal of the dams will eventually take place, in the interim the potential risks at these dams are mitigated by modifications performed to limit the amount of water

[53] Please refer to Hydro Dam Failure RAMP Risk Model (excel file).

that they can store. Consequently, the incremental risk reduction benefit from accelerating this work is relatively small in comparison to the cost. As shown in Table VIII-7 and Table VIII-8, Alternative Plan #1 costs approximately 75% more than the Proposed Plan, while only providing a risk reduction of approximately 11%.

4. Other Considerations

It is possible that in the course of the relicensing process it becomes apparent that decommissioning of the entire hydropower project is in the best interest of SCE and its customers, at which point the work may be accelerated. It is also possible that the relevant regulatory agencies may reject the partial removal of these dams and require complete removal, which would substantially increase the cost.

B. Alternative Plan #2

SCE developed Alternative Plan #2 as shown in Table VIII-9. The pre- and post- LoRE, CoRE and risk scores are summarized by tranche below in Table VIII-10.[54]

[54] Please refer to Hydro Dam Failure RAMP Risk Model (excel file) and WP. Ch. 12 –Hydro Dam Failure RAMP Financials.

Table VIII-9
Alternative Plan #2 (Total Costs Nominal $Millions and 2025 Risk Spend Efficiencies)[55]

ID - Tranche ID	Control / Mitigation Name	O&M 2025	Capital Total (2025 - 2028)	Average Annual Foundational Costs Allocated	2025 Risk Spend Efficiency
C1	Seismic Retrofit	-	$0.00	$0.00	
C2	Dam Surface Protection	-	$0.00	$0.00	
C3 - T3	Spillway Remediation and Improvement	-	$5.20	$0.12	
C3 - T4	Spillway Remediation and Improvement	-	$5.00	$0.12	104.0
C4 - T1	Low Level Outlet Improvements	-	$2.64	$0.06	0.0
C4 -T2	Low Level Outlet Improvements	-	$2.98	$0.07	
C4 -T3	Low Level Outlet Improvements	-	$1.12	$0.03	
C4 -T4	Low Level Outlet Improvements	-	$4.08	$0.09	
C5 - T3	Seepage Mitigation	-	$1.00	$0.02	
C5 - T3	Seepage Mitigation	-	$4.50	$0.07	155.5
C6 - T3	Instrumentation / Communication Enhancements	-	$0.10	$0.00	1.0
C6 - T4	Instrumentation / Communication Enhancements	-	$0.05	$0.00	230.7
M2 - T2	Relocation of Campgrounds	-	$5.00	$0.41	
M3	Purchase/Relocation of Inhabitable Structures	-	$0.00	$0.00	
M4 - T1	Dam Divesture	-	$5.00	$0.23	
	Total	**$0.00**	**$36.67**	**$1.23**	

55 Although no capital spending is identified in 2025-2028 for C1, C2 and M3, these measures are included because spending is expected to occur in 2022-2024, and has been modeled as part of the baseline risk calculation. The 2025 RSEs are not shown for certain Controls because risk-reduction benefits are not realized until project completion, and no projects in these categories are currently forecast to close in 2025.

Table VIII-10
Summary of Pre- and Post- LoRE and CoRE Risk Scores[56]

	Pre-Mitigation Risk Quantification Scores (End of 2024)			Post-Mitigation Risk Quantification Scores (End of 2028)		
	LoRE	**CoRE**	**Risk Score**	**LoRE**	**CoRE**	**Risk Score**
Hydro Dam Failure	0.0042	7.4	0.031	0.0040	5.2	0.021
T1 - Concrete Dams < 100 ft High	0.0012	1.4	0.002	0.0011	1.4	0.002
T2 - Embankment Dams < 100 ft High	0.0015	3.6	0.006	0.0015	3.0	0.005
T3 - Concrete Dams > 100 ft High	0.0010	6.3	0.006	0.0009	5.7	0.005
T4 - Embankment Dams > 100 ft High	0.0006	32.9	0.018	0.0004	20.6	0.009

1. Overview

SCE's Alternative Plan #2 includes all the measures in the Proposed Plan: C1 (Seismic Retrofit), C2 (Dam Surface Protection), C3 (Spillway Remediation and Improvement), C4 (Low Level Outlet Improvements), C5 (Seepage Mitigation), and C6 (Instrumentation and Communication Improvements) and M3 (Purchase/Relocation of Inhabitable Structures). It also includes M2 (Relocation of Campgrounds) and M4 (Dam Divesture).

2. Execution Feasibility

The US Forest Service (USFS), which operates most of the campgrounds downstream of SCE dams, has previously cooperated with SCE to close or restrict campgrounds and trails in response to potentially hazardous conditions. However, it is not anticipated the USFS would be amenable to long-term relocation; many of the campgrounds and campsites and campgrounds that would be most beneficial to relocate are also among the most popular, and usage of these facilities has increased substantially during the COVID-19 pandemic.

Regarding the divesture of high-hazard dams, the primary factor impacting success is whether there is one or more parties willing and able to assume operation of the facilities. SCE is currently attempting to divest several low-hazard hydropower projects; the response to these offerings may help in understanding the interest of outside parties.

[56] Please refer to Hydro Dam Failure RAMP Risk Model (excel file).

3. Affordability

Any agreement for permanent relocation of a campground would likely involve building or funding construction of a replacement site, which has been estimated based on SCE's previous experience with such efforts. Campground relocations may also cause adverse impacts to recreationists and the economies of local communities that serve them.

While it is possible that SCE would be able to obtain a positive sale price for a high-hazard dam, the additional complexity and regulatory requirements associated with ownership could result in a situation where the best offer is a negative price (i.e., the new owner requires payment to take the facility). At this time, SCE has taken a conservative approach to estimating the cost for divesture of a dam. However, if another party expresses strong interest in a high-hazard dam in the future, SCE would re-evaluate the situation and could pursue divesture if cost-effective or otherwise in customers' best interests. As shown in Table VIII-9 and Table VIII-10, Alternative Plan #2 costs approximately 37% more than the Proposed Plan, while only offering a risk reduction of approximately 11%.

4. Other Considerations

All transfers of ownership are subject to approval by FERC. The proposed new owner must demonstrate the technical and financial resources to continue the safe operation of the dam. These requirements are substantially greater for a High-Hazard dam, which may significantly limit the potential pool of buyers.

IX.

LESSONS LEARNED, DATA COLLECTION, & PERFORMANCE METRICS

A. Lessons Learned

SCE has identified capital projects over the 2022-2028 period that will reduce the risk of dam failure. However, the risk reduction potential is small compared to controls and mitigations identified in other RAMP risk chapters. This highlights a challenge many dam owners have experienced when trying to integrate dams into their Enterprise Risk Management programs: balancing management of frequently-occurring risks against very rare risks with catastrophic consequences.

Following the failure of the spillway at Oroville Dam in 2017, FERC made significant updates to federal dam safety regulations, including the formal incorporation of risk analysis.[57] These new regulations will drive an increase in the use of risk within the industry and should encourage the development and improvement of qualified experts, tools and procedures. However, as the new regulations only went into effect in April 2022, it may take several years to realize these benefits.

B. Data Collection and Availability

One of the challenges associated with the 2018 RAMP chapter is that there was no direct data on failure rates to draw from, since SCE has not experienced a dam failure comparable to those discussed in this Chapter. In the time since that report was release, the ICOLD analysis of worldwide dam failures was published. This allowed for a quantitative estimate of failure rates based on the age and type of construction of the dam. However, since it is a worldwide data set, the ICOLD database may not be representative of SCE's inventory of dams as factors such as seismicity, hydrology, and regulations can vary widely between countries. Consequently, SCE chose to average these failure rates with those generated from SCE's Dam Safety Risk Assessment program, which are based mainly on SME judgment.

The SME-based estimates are informed by the analysis and information obtained to date, and are examined in facilitated workshop settings that include SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD. SCE believes that evenly weighting the data-based and SME-based driver frequencies appropriately balances observed behavior with knowledge of the specific characteristics of SCE's dams.

SCE's pilot project currently being performed under the FERC RIDM Guidelines may offer a potential path to improving risk estimates through a combination of field investigations and additional numerical simulations. While this approach requires funding and is time-consuming, it could be a viable option for assessing the top dam safety risks going forward.

[57] "Final Rule, 18 CFR Part 12: Safety of Water Power Projects and Project Works." Federal Energy Regulatory Commission, Docket No. RM20-9-000, Order No. 888, December 16, 2021.

C. Performance Metrics

SCE currently tracks the following leading and lagging metrics related to dam safety performance:

Leading Indicators:

- DSOD Dam Condition Ratings (Note: FERC does not presently share its condition ratings, but is expected to make those rating public in the future)

Lagging Indicators:

- Number of significant and high-hazard dam failures
- Number of Emergency Action Plan Activations

SCE also evaluates a number of operational metrics pertaining to normal operations and dam safety, such as reservoir levels, stream flows, leakage measurements, and snowpack. Collectively, these data help us maintain safe and reliable dams. However, no single metric has been identified that provides a concise, meaningful measure of the safety of Hydro Assets. SCE will continue to evaluate and manage risk through our Dam Safety Risk Assessment Program.

X.

ADDRESSING PARTY FEEDBACK

A. 2021 GRC Decision

In SCE's Test Year (TY) 2021 GRC decision, the Commission made a Finding of Fact that "SCE provided reasonable justification for the inclusion of its hydro risk asset alternative mitigation plan in the 2018 RAMP Report."[58] The GRC decision included what appeared to be *dicta* that "encouraged" coordination between SCE and Cal Advocates regarding alternative migration plans for SCE's hydro risk assets in connection with the development of future RAMP submissions.[59]

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[58] D.21-08-036, p. 567, Finding of Fact 27.

[59] D.21-08-036, p. 37.

1. SCE's Follow-Up

In connection with preparation of its 2022 RAMP, SCE reached out to Cal Advocates to schedule a meeting to discuss SCE's planned alternative mitigations for hydro asset risk. SCE met with a Cal Advocates team on April 7, 2022. SCE briefed Cal Advocates in detail regarding the following: (a) SCE's planned controls and mitigations for the upcoming 2022 RAMP filing; (b) the specific controls and mitigations that SCE intended to select for SCE's Proposed Plan and two Alternative Plans; and (c) the reasons why individual controls and mitigations were included in the Proposed Plan versus an Alternative Plan.

SCE appreciates and thanks Cal Advocates for its courtesy and thoughtful questions during the meeting. SCE believes that the parties had a cooperative and productive conference, and received positive feedback from Cal Advocates on SCE reaching out and coordinating the meeting, and on the substantive nature of the briefing. At the meeting, SCE did not receive any specific feedback regarding items that Cal Advocates wished to see treated differently in the alternative mitigations. SCE is happy to continue the productive dialogue with Cal Advocates (as well as with any other interested party) regarding SCE's proposed or alternative mitigation plans to address hydro asset risk.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Appendix A

Battery Energy Storage Systems

Rosemead CA
May 13, 2022

RAMP - Appendix A: Battery Energy Storage Systems

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I.

BATTERY ENERGY STORAGE RISK OVERVIEW

SCE has a long history of safely operating Battery Energy Storage Systems (BESS). Since the 1980s, SCE has conducted laboratory testing, field demonstrations, scaled pilot deployments, and has built production systems. SCE deployed its first utility-scale lithium-ion (li-ion) BESS in 2009. SCE continues to partner with industry stakeholders and manufacturers to safely develop, deploy, and operate utility scale li-ion based BESS. Some of the entities we have collaborated with are the Electric Power Research Institute (EPRI), US Department of Energy (DOE), LG Energy Solutions (formerly LG Chem), and A123 Systems/NEC Energy Solutions.

This experience has provided SCE with an understanding of the unique operating characteristics and failure modes of li-ion chemistries; specifically, the need to maintain voltage, current, and temperature within appropriate tolerance limits for each battery cell. By constantly monitoring and maintaining these limits, operators can avoid undue stress, premature aging, and thermal runaway (see Section II below).

Despite SCE's extensive experience in safely operating BESS systems, SCE continuously monitors reports of safety incidents involving these utility assets throughout the world. There have been several recent examples of safety incidents from BESS systems, including li-ion BESS fires in South Korea (in 2018) and a li-ion BESS explosion in the US (in 2019).[1] In this Appendix, SCE has chosen to proactively address two BESS safety-related risks, as well as our approach to mitigate them. The two risks are: (a) thermal propagation risk and (b) decommissioning.

II.

OVERVIEW OF THERMAL PROPAGATION RISK

According to the National Fire Protection Association (NFPA), "Thermal runaway is the condition when an electrochemical cell increases its temperature through self-heating in an uncontrollable fashion and progresses when the cell's heat generation is at a higher rate than it can

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[1] *See* https://storagewiki.epri.com/index.php/BESS_Failure_Event_Database.

dissipate, potentially leading to off-gassing, fire, or explosion. Once thermal runaway has started in a battery cell, it cannot be stopped."[2]

Due to the intense heat generated by a cell undergoing thermal runaway, the adverse thermal condition may not stop at the initiating cell. Cascading thermal runaway, also known as thermal propagation, is thermal runaway that spreads from one cell to the next, potentially spreading throughout the battery module, rack (multiple modules), enclosure (multiple racks), and/or system (one or more enclosures).

One of these thermal propagation events occurred on April 19, 2019 at Arizona Public Service's 2 MW, 2 MWh li-ion McMicken battery facility. That event resulted in an explosion that also injured firefighters responding to the scene. According to the McMicken Battery Energy Storage System Event Technical Analysis and Recommendations report completed by DNV GL, the five contributing factors (CF) of this event were:

- CF #1: Internal failure in a battery cell initiated thermal runaway.
- CF #2: The fire suppression system was incapable of stopping thermal runaway.
- CF #3: Lack of thermal barriers between cells led to cascading thermal runaway.
- CF #4: Flammable off-gases concentrated without a means to ventilate.
- CF #5: Emergency response plan did not have an extinguishing, ventilation, and entry procedure.[3]

Because li-ion is the predominant BESS technology, most thermal propagation events have been associated with these types of batteries. However, other battery technologies are also subject to thermal propagation.

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[2] NFPA 855, Standard for the Installation of Stationary Energy Storage Systems, National Fire Protection Association.

[3] McMicken Battery Energy Storage System Event Technical Analysis and Recommendations, prepared for Arizona Public Service by DNV GL, July 18, 2020.

A. Thermal Propagation Drivers and Potential Outcomes

Depending on chemistry (e.g., li-ion, NaS) and specific system design, thermal propagation can occur due to several drivers, and can result in a number of outcomes. The potential drivers of thermal propagation are:

- Battery overheating
- Lithium plating
- Physical damage
- Power conversion system transient
- Incorrect charging (exceeding voltage, current, or temperature limits)
- Fire outside battery cell/module

The potential outcomes of thermal propagation are:

- Unit trip / battery unavailable
- Propagating fire due to thermal runaway
- Explosion
- Gas release[4]

B. SCE's Thermal Propagation Risk Exposure

SCE currently operates seven BESS sites with another six sites that are expected to be commissioned by the fourth quarter of 2022. There are an additional two sites in the planning stage. All the currently operational sites are relatively small systems (10MW or less) and are based on various designs from walk-in containers to outdoor enclosures.

Three of the six sites that are expected to be operational by the fourth quarter of 2022 are larger than the ones currently in operation (100MW or larger). These new sites, consisting of tens of battery enclosures, contain significantly more battery cells than the smaller systems. Therefore, they are at greater risk with regard to a single thermal event.

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[4] Battery Energy Storage System Site Evaluations Overview Report, prepared for Southern California Edison by Jensen Hughes, December 2020.

SCE has worked with the developers to pre-emptively mitigate this risk by utilizing a distributed architecture. This distributed architecture adheres to the most up-to-date industry safety practices, codes, and standards, and is designed to limit the effect of an event to one battery enclosure. For example, an event may spread through the initiating enclosure, but would not spread to adjacent enclosures separated by an engineered fire break.

Therefore, whether a thermal propagation event occurs at a smaller system consisting of one or two enclosures, or occurs at a larger system consisting of many enclosures, the 'scale' of the event should still be limited to the initiating enclosure. In some designs, such an event may be limited to an even smaller portion of the system, such as a single module or rack (depending on the specific BESS models employed). Even though SCE is building and operating more and larger BESS, our utilization of the latest best practices should decrease the risk that a thermal propagation event spreads beyond one enclosure.

C. <u>Thermal Runaway Risk Control Activities</u>

All of SCE's BESS sites adhere to industry safety practices, codes, and standards current as of the time that the sites were designed and built. Depending on the specific system design, the preventative controls may include:

- UL-tested cells and modules from major battery manufacturers
- Active battery management systems that maintain cell and module voltages, currents, and temperatures within normal operating ranges
- Supporting subsystems such as thermal management and power conversion
- Subsystem integration through site-level controls, including remote monitoring
- Component isolation/system trip
- Cell/module/rack, power conversion, and system-level fusing/protection
- Ground fault detection
- Fire protection systems that may include interlocked smoke, heat, and flame detection, signaling/alarms, and clean agent fire suppression
- Cell/module separation, and cell/module barriers, to reduce thermal propagation

Newer systems employ additional features that incorporate the latest safety practices, codes, and standards. These may include:

- System-level UL listing
- UL-compliant testing of cells, modules, racks, and enclosures to determine thermal propagation characteristics and the effectiveness of mitigative design features
- Gas monitoring to detect the presence of thermal runaway or explosive gas
- Ventilation systems to prevent the buildup of explosive gas in battery enclosures
- Deflagration vents to safely release overpressure from an explosion
- Water-based fire suppression

Industry understanding of BESS safety and thermal propagation risk has changed since some of SCE's systems were built. Immediately following the APS system explosion event in Arizona (in April 2019), SCE reevaluated its guidance to first responders and the public. Resulting refinements included:

- Adding a BESS chapter to SCE's first responder electrical safety training video and website. This chapter instructs first responders to treat SCE-owned BESS sites in the same way the first responders approach SCE substations (i.e., do not enter unless escorted by a qualified SCE employee).[5]
- Adding a BESS safety section for customers on SCE's website.[6]

SCE also hired a third-party consultant, Jensen Hughes, to assess the safety of its existing utility-owned BESS. Based on this assessment, SCE implemented several changes to improve the operational safety of the sites, as well as prevent injury to first responders in the case of thermal propagation. Based on their recommendations, SCE modified its practices by:

- Updating site signage to align with the latest BESS fire codes
- Removing unnecessary spare parts and materials from battery enclosures
- Developing and distributing pre-fire emergency response plans to first responder agencies

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[5] *See* https://sce.e-smartresponders.com/topic/battery-energy-storage-system-safety.

[6] *See* https://www.sce.com/safety/bess/.

SCE is in the process of evaluating additional changes to existing systems to improve safety and reduce thermal propagation risk. Approaches that are under consideration include the following:

- Deactivating and removing clean agent fire suppression systems which may compound, rather than prevent, thermal runaway or propagation by allowing a buildup of explosive and toxic gas
- Retrofitting ventilation systems to prevent or mitigate explosion
- Reduce the need to approach a battery enclosure during thermal propagation

SCE has also engaged agencies that have SCE-owned BESS in their service areas through provision of safety training materials, tours, and site-specific emergency response plans. These measures help ensure that first responders properly understand BESS emergency response hazards, and do not approach an SCE-owned BESS without a qualified escort. In addition to signage complying with BESS fire codes, all of SCE's BESS sites use similar fences and signage as SCE substations, making them immediately recognizable as SCE electric facilities, and helping to ensure first responders do not try to enter without being accompanied by qualified escort.

III.

OVERVIEW OF BESS DECOMMISSIONING RISK

SCE recognizes the challenges associated with decommissioning BESS sites. Articulating the requirements for BESS site decommissioning is a relatively new type of activity that requires special attention. SCE is working with industry partners, exploring best practices, and reviewing lessons learned regarding how to dispose and recycle BESS components. As discussed below, SCE ensures that for the large industrial batteries used in stationary energy storage systems, safety regulations and other federal or state industrial safety regulatory agency requirements are followed.

The following section gives an overview of the completed decommissioning activities associated with SCE's two oldest li-ion BESS which reached the end of their useful life: one at SCE's Equipment Demonstration & Evaluation Facility (EDEF) and one at University of California Irvine (UCI).
SCE plans to decommission a third system, known as the Tehachapi Storage Project. This system was a successful demonstration in cooperation with the Department of Energy (DOE); plans for

decommissioning are discussed in advice letter AL-4568-E pending final Commission approval. At this time, SCE does not foresee any other decommissioning projects during the upcoming GRC period (2025-2028).

A. Decommissioning Location and Overview of System

The two BESS that were decommissioned were located at SCE's Shawnee Substation and UCI's University Substation (in December 2020). Each BESS was rated 2MW, 0.5MWh, and housed the batteries and inverters in a 53-foot container. The ancillary electrical equipment was installed on a pad or skid adjacent to the container.

B. Decommissioning Oversight by SCE

SCE oversees the performance of all decommissioning activities, whether by utility personnel or contractors. The purpose of SCE's oversight is to help ensure that: (1) each decommissioning scope of work is performed safely and in accordance with site procedures; and (2) the site is restored to a safe condition suitable for future uses. Through its active oversight, SCE will halt decommissioning work if decommissioning activities are not conducted in accordance with safety and/or regulatory requirements. For example, if a work scope involves the demolition, removal, and disposal of particular equipment and its foundations, SCE's oversight helps ensure that the equipment and foundations are removed safely and in their entirety. It also helps ensure that the disposal of all associated waste materials is performed and appropriately documented according to applicable regulatory requirements.

C. Pre-Decommissioning Activities

During pre-decommissioning, SCE investigates the appropriate governing authorities' requirements and applicable federal, state, and local permits for the decommissioning and restoration activities.

D. Decommissioning Activities

Decommissioning is the process of removing of BESS structures, as well as evaluating and categorizing all components and materials into categories of reconditioning and reuse, salvage, recycling, and disposal. The categorized equipment is then transported to the appropriate facilities for reconditioning, salvage, recycling, or disposal. SCE has conducted decommissioning activities for a number of sites mentioned above.

In these decommissioning activities, SCE disassembled and disposed of BESS and ancillary electrical equipment at the EDEF and UCI sites. During this process, subject matter experts from various SCE organizations[7] worked collaboratively to develop the scope of work and establish appropriate requirements for the decommissioning work. SCE's expert resources also worked with a third party contractor to carry out the activities. The contractor followed SCE's waste management policy, which is designed to minimize health and environmental contamination risks, while prioritizing safety.

E. Post-Decommissioning Activities

Post-decommissioning activities involve the remediation of the pre-existing BESS sites. These activities include: disposing and transporting the equipment to the SCE-approved recycling facility. The site foundations (concrete slabs and pads) where the BESS was located generally remain in place. The surrounding area is cleaned and restored to original conditions. Fencing is removed to facilitate component loading, and then the fencing is reinstalled as per SCE requirements. Electrical conduits remain buried, while electrical cables are removed and secured.

IV.

THE PATH FORWARD

SCE intends to continue to evaluate the risk of its BESS operations and make appropriate changes to existing systems and new procurements, by incorporating lessons learned from BESS events and updates to industry safety practices, codes, and standards. SCE will also continue to share information with industry stakeholders through engagements with research organizations, national labs, safety forums, first responder agencies, and customers.

With regard to decommissioning specifically, relatively few BESS in our country have confronted end-of-life issues and undergone decommissioning. Thus, standardization of decommissioning activities has not yet become fully mature. Collaboration and careful attention to

[7] These organizations included Hazardous Materials & Waste Management, Investment Recovery, Site Characterization & Remediation, Air Quality, Field Operations, and Supply Management.

lessons learned from decommissioning activities (our and others') should help develop refined processes and procedures when decommissioning a BESS facility is needed.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Appendix B

Climate Change

Rosemead CA
May 13, 2022

Appendix B: Climate Change

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I.

INTRODUCTION

Climate change is a central concern for SCE, just as it is for the Commission and for so many Californians. In this Appendix, SCE addresses certain aspects of its efforts to help carry out the State's climate change goals, including resiliency to the effects of climate change. To place this Appendix in context, SCE offers the following five points.

First, under RAMP criteria established by the Commission, only a relatively narrow subset of climate change issues and strategies for mitigations fall within the parameters that are used to determine RAMP risks. Climate change is a long-term concern that will be faced not just in the next several years, but in the next several decades, at least. And the impacts of climate change are not simply felt in the safety realm, but also in reliability, financial, and other critical areas.

In a way, these aspects of climate change stand in contrast to the stated goals and boundaries of a utility's RAMP report. RAMP primarily examines and assesses the top safety risks that the utility faces in the shorter-term. But climate change is a risk whose direct safety impact today and in the shorter-term constitutes a relatively small portion of the totality of the risks, consequences, and outcomes that climate change is expected to bring in the next 10, 20, or 40 years.

Thus, despite its critical importance and significant projected effects on public and private interests in the long run, the parameters and restrictions for RAMP risk calculations mean that climate change does not rise to the level of being one of the top safety risks that SCE faces in the near-term years that make up this RAMP cycle. The place where climate change "lands" as a stand-alone safety risk under RAMP constraints is neither a true measure of its importance nor an accurate reflection of the priority that SCE places on it. In addition, SCE recognizes that accelerating climate change is currently exacerbating – and will continue to exacerbate throughout this RAMP period – the most serious current safety risk facing SCE and its customers, namely wildfire risk.

Second, in recognition of the long-term stakes that exist with respect to climate change, the Commission has directed the utilities to file long-term Climate Adaptation and Vulnerability

Assessments (CAVAs).[1] SCE's CAVA is being filed on the same date as this RAMP report, and is the first to be filed among the large California Investor-Owned Utilities (IOUs).

There are important contrasts between what the Commission asks for in the RAMP and what the Commission asks for in the CAVA. RAMP must identify and examine the highest and most immediate stand-alone safety risks that are implicated in the utility's activities and delivery of electricity to its customers. In assessing assets, operations and services (AOS), the CAVA must assess the vulnerability of the utility to the damaging effects of climate change on AOS.

Moreover, the temporal scope of the RAMP is near-term (i.e., it ends in 2028). The temporal scope of the CAVA assessments is longer-term. In the Commission's words, an IOU filing a CAVA must "[a]ddress the key time frame to be considered by the vulnerability assessment of the next 20 to 30 years. Also address the intermediate time frame of the next 10 to 20 years and the long-term time frame of the next 30 to 50 years."[2]

The adaptation options presented in the CAVA (and summarized in this Climate Change Appendix) are not RAMP mitigation proposals. Rather, they should be viewed through the lens of being potential options for consideration that are expected to be refined prior to the filing of SCE's Test Year 2025 General Rate Case (GRC). The adaptation option proposals are therefore not yet sufficiently developed to calculate specific risk spend efficiency values and be incorporated into the individual RAMP risk chapters at this time. Thus, the two filings do not neatly intersect for integration purposes.

Third, under the procedural schedule established by the Commission, the RAMP and CAVA file on the same date. As a result, the two regulatory submissions were developed in parallel rather than in serial fashion. SCE has worked to appropriately integrate CAVA results into the RAMP showing, but the RAMP is not the endpoint of integration of the CAVA. As mentioned above, over the next year SCE will diligently continue its exploration of wider integration of the CAVA analyses and adaptation options into affordable and actionable activities and projects that may be proposed in SCE's 2025 GRC.

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1 The CAVA is discussed in detail below.

2 D.20-08-046, p. 125, Ordering Paragraph 9.3. This decision is referred to in this Appendix as the "CAVA Decision."

Fourth, SCE is currently engaged in very significant efforts to mitigate the effects of climate change. Today, those efforts must take the form of mitigating the risk of climate-driven wildfires. The safety risk and devastating impact of California's wildfires have arisen from conditions created or directly exacerbated by climate change. SCE's nearer-term mitigation work to address the impacts of climate change focuses on the most immediate threat to the safety and well-being of our customers and communities.

Fifth, in addition to identifying and adapting to longer-term asset and operation vulnerabilities from the effects of climate change, SCE is a national leader among utilities taking significant steps to reduce greenhouse gases (GHGs), to mitigate climate change as feasible, and help meet State and Federal climate change goals by driving a clean energy transition. We provide further details immediately below.

II.

SCE'S ACTIONS TO REDUCE CLIMATE CHANGE

SCE is proud to be a nationally recognized leader in the clean energy transition, delivering power to customers within California, which has some of the most ambitious science-based climate-change goals in the U.S. SCE is required by the State to meet the following retail sales requirements for the power it delivers to customers:[3]

- By 2020 – 33% of power from Renewables Portfolio Standard (RPS)-eligible resources. In 2020, SCE met this requirement with 43% of retail sales from carbon-free resources.
- By 2030 – 60% of power from RPS-eligible resources.
- By 2045 – 100% carbon-free power.

Over the past five years, SCE has published four whitepapers outlining the cross-sector collaboration that is essential for reaching California's climate goals. SCE's first whitepaper, the Clean Power and Electrification Pathway,[4] was published in 2017. The document presented an integrated

3 *See* https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan.

4 *See* The Clean Power and Electrification Pathway at https://www.edison.com/home/our-perspective/pathway-2045.html?msclkid=f9647412cf1511ecbd09ef90eef895e4.

blueprint that outlines the most feasible and cost-effective approach for California to reduce GHGs and air pollutants by 2030. SCE's analysis indicates that California needs to achieve 80% carbon-free electricity by 2030, along with emissions reductions in other sectors through electrification (e.g., transportation and buildings), in order to affordably meet the State's GHG emissions reduction targets. SCE is advocating, as part of an economy-wide approach, that California go beyond the current 2030 goal of 60% RPS-eligible power delivered to customers, and that the State enact complementary policies that reduce emissions from transportation and buildings through electrification.

In 2019, SCE's Pathway 2045 whitepaper[5] identified five key actions for affordably achieving carbon neutrality by 2045, reflecting the State's expanded climate change commitment. SCE published a third whitepaper, Reimagining the Grid,[6] in 2020. It comprehensively assesses the grid changes that are needed to support California's GHG emissions reduction goals while adapting to evolving customer and climate change-driven needs. SCE's latest whitepaper, Mind the Gap: Policies for California's Countdown to 2030,[7] was published in 2021. It presents an analysis of the policy changes and additions needed to ensure that California meets its goal of reducing GHG emissions 40% by 2030 – a reduction that is essential if the State is to achieve carbon neutrality by 2045.

As noted above, SCE is investing in enabling the electrification of transportation and buildings, two other required components of the State meeting its 2030 GHG goals. SCE's Charge Ready Transport program[8] is the largest truck and transit charging initiative by a single IOU in the nation. In 2020, this program spurred progress on supporting medium- and heavy-duty electric vehicles in areas most impacted by pollution. SCE anticipates the program will support at least 8,490 electric fleet

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[5] *See Pathway 2045 at https://www.edison.com/home/our-perspective/pathway-2045.html?msclkid=f9647412cf1511ecbd09ef90eef895e4*.

[6] *See Reimagining the Grid at https://www.edison.com/home/our-perspective/pathway-2045.html?msclkid=f9647412cf1511ecbd09ef90eef895e4*.

[7] *See Mind The Gap Policies For California's Countdown To 2030 at https://www.edison.com/home/our-perspective/pathway-2045.html?msclkid=f9647412cf1511ecbd09ef90eef895e4*.

[8] *See https://crt.sce.com/overview*, a $356 million program.

vehicles. SCE also received approval for an important extension of its Charge Ready[9] passenger vehicle charging program – equating to 38,000 additional charge ports across our region. These accomplishments and more earned SCE a place on the Smart Electric Power Alliance's Utility Transformation Leaderboard[10] in April 2021.

In a notable step, in December 2021 SCE proposed programs to support installation of approximately 250,000 electric heat pumps and to provide approximately 65,000 households with electrical service panel and circuit upgrades across our service area.[11] If approved by the Commission, our plan would accelerate the widespread replacement of major fossil fuel heating appliances in homes and buildings. The actions proposed will ultimately benefit all SCE customers through reduced GHG emissions and improved air quality.

Furthermore, SCE administers the California Clean Fuel Reward program, a statewide program launched in November 2020. This program offers up to a $750 electric vehicle rebate at the time of purchasing or leasing a new electric vehicle.[12] Since it launched, the California Clean Fuel Reward program has provided over $300 million in rebate incentives to over 250,000 customers throughout California, in connection with purchasing or leasing new electric vehicles.[13] For pre-owned electric vehicles specifically, SCE began providing rebates in 2021 through our Pre-Owned Electric Vehicle Rebate Program.[14] SCE also had a program in 2020 that offered residential customers $6,000 cash back on a 2020 Nissan Leaf or Leaf Plus.

Finally, SCE's energy-efficiency programs incentivize customers to make changes that result in more efficient use of electricity. These changes include replacing old appliances, such as heating and air-conditioning systems, and lighting and industrial process equipment. The old appliances are replaced

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9 *See https://www.sce.com/evbusiness/chargeread*, a $436 million program.

10 *See https://sepapower.org/event/utility-transformation-challenge-event/*.

11 *See* Application 21-12-009 of Southern California Edison Company (U 338-E) for Approval of its Building Electrification Programs. This is a $677 million proposal.

12 *See* https://cleanfuelreward.com/.

13 *See* https://cleanfuelreward.com/reporting.

14 *See* https://evrebates.sce.com/.

with energy-efficient models. In 2020, SCE offered more than 90 energy-efficiency programs that saved 1,490 gigawatt hours (GWh) of energy. This translated to approximately 555,000 tons of avoided GHG emissions, and also saved customers about $39.7 million on their bills.

III.

CLIMATE ADAPTATION AND VULNERABILITY ASSESSMENT

A. Background of CAVA

As referenced above, SCE has conducted a CAVA to identify and address vulnerabilities and risks associated with climate change on SCE's AOS. The CAVA assessment was performed as required by D.20-08-046. Concurrently with this RAMP filing, the CAVA is being provided to the associated service lists for SCE's RAMP application. The purpose of this Appendix is to highlight key findings from the CAVA that may relate to the RAMP scope. This principally consists of potential adaptation options to address identified risks in the 2030 timeframe that may need to be commenced or implemented in the timeframe of the Test Year 2025 GRC. Please refer to the CAVA itself for the full description and discussion of process and results.

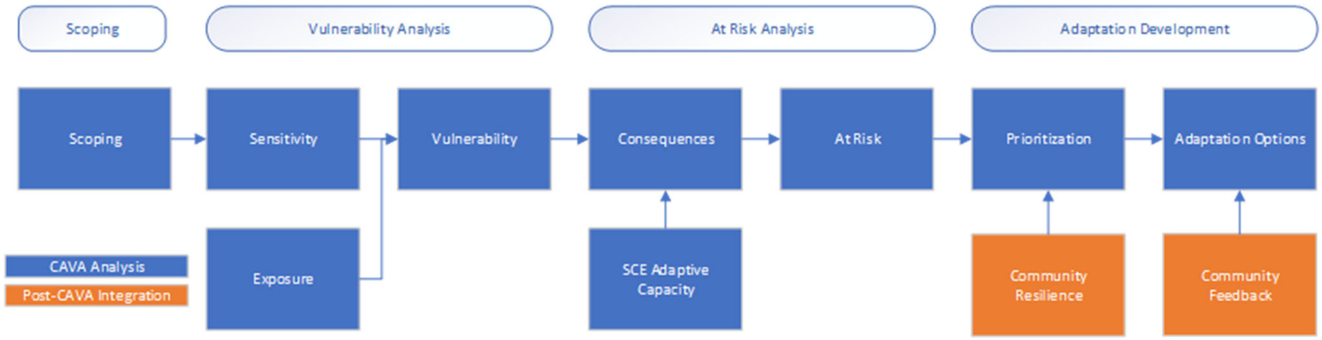
B. Risk Definition and Scope

Climate change is unique as a risk factor, since it can both result in standalone risk events that require adaptations (e.g., flooding of SCE assets causing safety, reliability, and/or financial consequences) and increase the likelihood or outcomes of existing enterprise-level risks (e.g., heat and drought increasing both the likelihood and severity of wildfires). In addition, climate change is a sufficiently expansive topic that its risks span across multiple risk variables (including wildfire, extreme heat and cold, flooding, sea level rise, and cascading events such as debris flow) and its timeframes run far beyond the current RAMP window of analysis. The CAVA analysis considers this wide range of impacts, and presents a potential array of adaptations to address them.

C. CAVA Analytical Framework

The CAVA analytical framework, depicted in Figure III-1, is made up of four primary phases: 1) Scoping, 2) Vulnerability Analysis, 3) At-Risk Analysis, and 4) Adaptation Development.

Figure III-1
Vulnerability Assessment Analytical Framework



The **Scoping phase** identifies which types of AOS need to be considered in the Vulnerability Analysis phase, and how those AOS should be studied, for each climate hazard. This creates a list of in-scope AOS for each climate hazard in connection with the Vulnerability Analysis phase of the analytical framework.

The **Vulnerability Analysis phase** determines the climate hazards AOS will be exposed to, and whether the AOS sensitivity to a specific climate hazard is high enough to result in significant consequences. To understand exposure, the CAVA considered future projections for extreme temperatures, wildfire, precipitation and flooding, sea level rise, and cascading events in the 2030, 2050, and 2070 timeframes. The projections were then compared to the sensitivity metrics of AOS to determine if there would be any potential significant consequences, such as asset failure, due to that exposure. Any AOS determined to be both exposed and sensitive to an individual climate hazard is deemed to be "vulnerable" and considered for further analysis in the At-Risk phase of the analysis.

The **At-Risk Analysis phase** determines whether the vulnerability results in significant consequences that need to be mitigated. To understand consequences, the potential safety, reliability, and financial consequences of the vulnerabilities are estimated. SCE also considers Adaptive Capacity to determine whether existing or planned measures are sufficient to reduce the consequences to an acceptably low enough level or to minimize the likelihood that the potential consequences occur. Adaptive Capacity may include transferring load to adjacent circuits that minimize customer outages in the event of a resource failure, as well as existing infrastructure replacement programs that are expected to result in upgrades to vulnerable equipment before climate hazards are predicted to cause vulnerabilities.

If SCE determines that a vulnerable AOS poses a risk of significant consequences requiring mitigation, and that there is insufficient Adaptive Capacity to minimize the risk, then the AOS is determined to be At-Risk and is considered further in the Adaptation Development phase.

The **Adaptation Development phase** generates and presents options to address At-Risk AOS for each climate hazard independently, and outlines and plans for potential next steps. Risk reduction impacts of a proposed adaptation option across multiple climate hazards were not considered in the CAVA but may be incorporated in further analysis to inform GRC requests.

At-Risk AOS that are present by 2030 will be further evaluated incorporating Community Resilience. Community Resilience is a combination of how sensitive a community is to loss of utility service and its adaptive capacity to withstand the corresponding impacts. Each census tract in SCE's service area can potentially be assigned a Community Resilience score, which along with other planning and operational factors, can help prioritize where adaptation measures are deployed.

Finally, SCE intends to use Community Impact to measure how a particular community may be affected when the proposed adaptation alternative is deployed, informed by feedback from that community. This can help inform the selection of the preferred alternative for a particular community when refining adaptation options. Potential adaptations that may be presented in the GRC are described below, with the expectation that presented options may be removed and other options may be added before the GRC filing.

D. Climate Adaptation Vulnerability Assessment Potential Adaptation Options

The CAVA must outline an "array of options for dealing with vulnerabilities, ranging from easy fixes, where applicable, to more complicated, longer term mitigation, and an indication of the IOUs' plans for potential next steps."[15] Following this guidance, the adaptation options presented in the CAVA (and summarized in this Climate Change Appendix) are not RAMP mitigation proposals. Rather, they

[15] CAVA Decision, p. 125, Ordering Paragraph 9.1.

should be viewed as potential options that are expected to be refined. Adaptations presented in the CAVA may also be further refined with respect to community adaptive capacity and equity, sustainability, and local government coordination considerations. After future refinements, all or a subset of these adaptation measures may be proposed for funding in the 2025 GRC.[16] SCE may also identify additional vulnerabilities and adaptations over the next 12 months and include discussion of those issues and potential mitigations in the 2025 GRC.[17]

Table III-1 below summarizes potential adaptation options identified in CAVA[18] that currently appear to fit within the RAMP and the 2025 GRC period (i.e., 2025-2028). For additional details, please refer to the Section VI of the CAVA. That section is titled Near-Term Adaptation Options.

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16 SCE's TY 2025 GRC will cover test year 2025 and attrition years 2026 – 2028.

17 It is also possible that additional climate models may augment CAVA results in the GRC.

18 Since the CAVA and the RAMP were being developed concurrently to be filed on the same day, a reasonably advanced draft version of the CAVA was summarized in Table III-1. In the event there are any discrepancies in language between the description of measures in the final RAMP and the final CAVA, the CAVA should be relied upon as the most up-to-date information.

Table III-1
Potential 2025 – 2028 Adaptation Options Identified in CAVA

Climate Hazard	Potential Outcome/Consequence	Potential 2025 – 2028 Adaptation Options
Wildfire*	Transmission Outages	1. Increased inspections, vegetation management, and tower clearing to reduce likelihood of fire damage 2. Expand remote inspection technology, LiDAR & Satellite Imagery
	Subtransmission Outages	1. Fire wrapping poles, increased inspections, vegetation management, and pole brushing to reduce likelihood of fire damage 2. Expand remote inspection technology, LiDAR & Satellite Imagery
	Distribution Outages	1. New underground wires solutions to create ties between exposed circuits for increased operational flexibility 2. Expand remote inspection technology, LiDAR & Satellite Imagery
	Big Creek Hydro System Outages	1. Vegetation Studies to understand wildfire risk profile after Creek Fire 2. Based on vegetation study results, installing redundant power and communication equipment to maintain necessary water management capabilities during wildfire events
	Employee Safety	1. Upgrading Heating, Ventilation, and Air Conditioning (HVAC) equipment in Vehicle Maintenance facilities at one service center to reduce potential smoke inhalation
Extreme Heat	Distribution Outages	1. Targeted substation and distribution transformer replacements 2. PME/PMH switch derates for fully loaded switches or replace with switches with modified equipment standards in high temperature exposure locations
	Substation Outages	1. New wires to create ties between exposed substations for increased operational flexibility and review ability for spare transformers
	Thermal Generation Outages	1. Upgrading Heating, Ventilation, and Air Conditioning (HVAC) equipment to reduce likelihood of heat related outages
	Employee Safety	1. Upgrading Heating, Ventilation, and Air Conditioning (HVAC) equipment in Vehicle Maintenance facilities at two service centers
Precipitation/ Flooding	Substation Outages	1. Construction of floodwalls to reduce likelihood of flood related outages at two substations
	Distribution Outages	1. New wires to create ties between exposed circuits for increased operational flexibility 2. Replace pad-mounted transformers, switches, and capacitors with waterproof equivalents
	Dam Overtopping	1. Perform Stochastic Event Flood Modeling analysis for all high hazard dams to understand climate change effects on dam safety concerns
Cascading Events	Distribution Outages	1. New underground wires solutions to create ties between exposed circuits for increased operational flexibility 2. When retrofitting these assets to mitigate other risks, consider undergrounding exposed overhead lines and equipment
	Big Creek Outages	1. Install debris booms near fire damaged areas to prevent debris flow into water systems
All	Climate Science Gaps	2. Studies to better understand nature of climate risk in areas of highest impact to SCE AOS

** The CAVA analysis focuses on the risk of wildfires – caused by any type of ignition – to SCE assets.*

IV.

LESSONS LEARNED

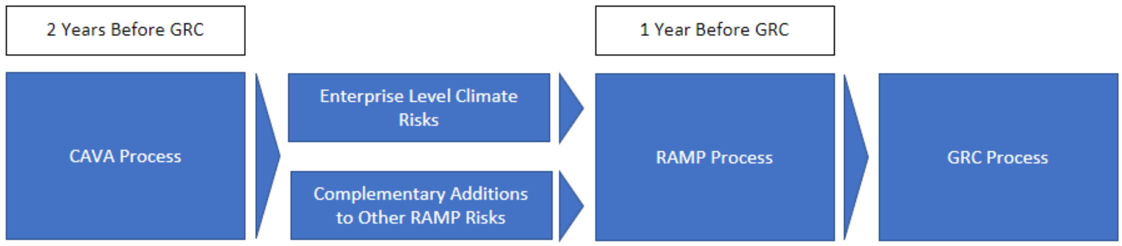
A. CAVA and RAMP Timing

The 2022 CAVA is the first filing of its kind by SCE, and many insights have been gained as part of the development process. In future years, as a refinement to the alignment between the CAVA and RAMP, SCE respectfully suggests that the Commission consider placing some separation between the filing date of the CAVA and the filing date of the RAMP, rather than having both filings be submitted on the same date. There is currently a one-year separation between the filing of the RAMP and the GRC. In a manner generally consistent with this timeframe, the Commission may wish to consider having the CAVA submitted one year before the RAMP, and thus two years before the GRC. This should allow for a more orderly process in first finalizing the CAVA analyses, results, adaptation options, and then incorporating that final work product into the RAMP preparation process.

The CAVA process has multiple outputs that might be utilized in more concerted fashion in RAMP. First, the CAVA may identify risks that should be considered along with other enterprise-level risks as part of the risk selection process. These risks could include flooding of SCE assets, or other climate-related hazards leading to significant safety risks. If the CAVA is completed a year before the RAMP, specific short-term CAVA findings can be considered in parallel with other potential enterprise-level risks for potential inclusion as main chapters within the RAMP. In addition, any prompt feedback from the Commission regarding the finalized CAVA can then be incorporated into the CAVA/RAMP integration efforts as the RAMP is developed.

Second, the CAVA may identify risks and/or adaptation options that integrate with existing RAMP Risks. For example, the CAVA is tasked with studying vulnerabilities to operations and services that could result in findings related to employee safety, including increased drivers of employee safety risk events and potential solutions to reduce the likelihood or consequences for employee safety risk events. With sufficient lead time, the finalized CAVA findings could be more thoroughly integrated as appropriate into the RAMP Employee Safety Risk chapter.

Figure IV-2
Draft Proposal for CAVA and RAMP Integration and Timelines



SCE also notes that climate change impacts will be included in the discussions amongst stakeholders as part of the Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities proceeding (Risk OIR).[19] SCE plans to share these lessons learned, and continue the discussion and collaboration, in any future Risk OIR workshops or technical working groups that address climate change impacts.

V.

ADDRESSING PARTY FEEDBACK

At the December 6, 2021 RAMP pre-filing workshop, SCE was asked to address two specific items:

1. *What actions are being taken by SCE to reduce climate change.*

Please refer to Section II of this Appendix for a summary of actions that SCE is taking to reduce climate change.

2. *How SCE is addressing equity concerns within its climate adaptation strategy development.*

Equity and Social Justice Considerations. As part of SCE's CAVA, we worked closely with communities and CBOs to develop a framework to help promote equity between Disadvantaged and Vulnerable Communities and non-Disadvantaged and Vulnerable Communities. This framework

[19] *See* R.20-07-013, Assigned Commissioner's Phase II Scoping Memo and Ruling Extending Statutory Deadline, p. 5: "Should the Commission consider methods and requirements for incorporating climate change related risks, such as those associated with wildfires and rising sea levels, into the RDF, consistent with adaptation and resiliency efforts underway in R.18-04-019 and other proceedings?"

includes two components, one to assess Community Resilience and the other to assess Community Impact.

Community Resilience is a combination of how sensitive a community is to loss of utility service and its adaptive capacity to withstand the corresponding impacts. Each census tract in SCE's service area can potentially be assigned a Community Resilience score, which along with other planning and operational factors, can help prioritize where adaptation measures are deployed.

Community Impact, on the other hand, is intended to measure how a particular community may be affected when the proposed adaptation alternative is deployed, informed by feedback from that community. This can help inform the selection of the preferred alternative for a particular community.

SCE's Community Adaptive Capacity and Equity framework is detailed in Appendix B of the CAVA.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Appendix C

Transmission and Substation Assets

Rosemead CA
May 13, 2022

Appendix C - Transmission and Substation Assets

Table of Contents

I.

Executive Summary

Among its portfolio of electric grid assets, Southern California Edison (SCE) owns and maintains transmission lines, sub-transmission lines, and substations. These assets are essential for transmitting power over long distances, maintaining grid reliability and resiliency, and serving the energy demands of our customers.

This Appendix explores certain potential but direct[1] safety risks associated with transmission lines, sub-transmission lines, and substation assets that are not addressed within SCE's RAMP Risk chapters. The safety impact of the risk associated with these assets did not rise to the level of inclusion as a top safety risk within our RAMP report. SCE has not experienced a CPUC-reportable public serious injury or fatality (SIF) as a result of failed substation and/or transmission assets in recent years.[2] However, there is always the potential that an in-service failure of a transmission and/or substation assets could lead to a public SIF. Therefore, we feel it is important to include, in an Appendix, the actions SCE takes to reduce the failure of these assets which could result in safety, reliability and financial consequences.

A. Addressing Party Feedback and Related Factors Discussion

1. Addressing Feedback from the 2018 RAMP

In the course of reviewing SCE's 2018 RAMP report, Cal Advocates provided various recommendations. SCE addressed each of the recommendations in a supplemental testimony exhibit in SCE's Test Year (TY) 2021 General Rate Case (GRC).[3] Below, SCE provides a follow-up discussion regarding two specific recommendations that are germane to this Appendix.

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1 Direct safety impacts are first-order consequences of risk events that directly result in an injury or fatality.

2 SCE has had public SIFs as a result of individuals trespassing in substations, and climbing transmission equipment in apparent attempts to commit suicide.

3 *See* "Comments of the Public Advocates Office on November 2018 Submission of Southern California Edison Company's Risk Assessment and Mitigation Phase," dated June 14, 2019, I.18-11-006, pp. 36-37.

a) Cal Advocates Recommendation: "SCE Should Clarify Which of its Proposed Transmission and Substation Measures are Existing Controls Versus New Mitigations"

Similar to SCE's 2018 RAMP report, this current RAMP Appendix was developed to illustrate the general risks associated with SCE's transmission and substation assets. At SCE's December 6, 2021 RAMP Pre-Filing Workshop, SCE discussed the planned approach and parameters for the Appendix. No stakeholder provided any feedback or expressed any concerns.

For purposes of this Appendix, SCE is using the generalized term "risk remediation activities" to encompass compliance-based work, controls, and mitigations. SCE presents its risk analysis regarding these assets, but notes that this analysis was not meant to follow the requirements associated with the top safety risks and their respective RAMP Risk chapters.

b) Cal Advocates Recommendation: "SCE Should Consider and Present the Impacts of Climate Change to Transmission & Substation Assets"

SCE shares the Commission's and Cal Advocates' concerns with regard to climate change, and the RAMP Climate Change Appendix outlines our committed efforts and engagement in this area.[4] That Appendix also summarizes SCE's Climate Adaptation Vulnerability Assessment (CAVA), which assesses potential vulnerabilities of SCE assets, operations and services to future climate change events. The CAVA is addressed below, and discussed in greater detail in the Climate Change Appendix. As discussed in the Overview chapter and the Climate Change Appendix, the particular lens of RAMP does not necessarily capture the true long-term risks that spring from climate change impacts.

Other stakeholders are making sustained efforts as well. The California Independent System Operator (CAISO), as part of the 2021-2022 planning cycle, conducted studies that assess both demand-driven needs, as well as potential for reliability-driven needs, based on various Public Safety Power Shutoffs (PSPS) and wildfire-related outages scenarios in SCE's service area.

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[4] For reasons of brevity and judicial economy, the Climate Change Appendix does not exhaustively discuss each and every effort that SCE is making or engaged in with respect to climate change.

The CAISO energy demand forecast used in the referenced analysis is based on the California Energy Commission (CEC) 2020 Integrated Energy Policy Report (IEPR) mid-demand case. That mid-demand case incorporates the impact of "extreme temperature peak demand" and accounts for other "climate change modifiers."

CAISO also conducted studies to assess the potential risks of de-energizing CAISO-controlled facilities in the SCE High Fire Risk Areas (HFRA) due to significant wildfire or PSPS events. CAISO identified no opportunities for transmission projects to reasonably mitigate the impacts of wildfire or PSPS events through the 2030 timeframe. Additionally, SCE has conducted a separate analysis on the potential impact of climate change on increasing wildfire and PSPS consequence for distribution and transmission assets.[5]

SCE also notes that climate change impacts will serve as a concrete part of the discussions amongst stakeholders as part of the Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities proceeding (Risk OIR). Specifically, the Phase II Roadmap in the Risk OIR recommends that parties prioritize discussions on the methodology for incorporating climate change-related risks associated with wildfires and rising sea levels into the Risk-Informed Decision-Making Framework, consistent with climate change adaption and climate resilience efforts underway at the Commission in R.18-04-019.[6]

SCE recognizes the potential impacts that climate change could have on SCE's infrastructure, planning processes, and ability to continue to provide safe, reliable, affordable, and clean energy. In accordance with D. 20-08-046, SCE has prepared its CAVA, which is being filed concurrently with this RAMP filing. The CAVA identifies assesses climate change-driven vulnerabilities of SCE's assets, operations and services. In order to assess climate exposure, the CAVA considered projections for extreme temperatures, wildfire, precipitation and flooding, sea level rise, and cascading events such as debris flow. Decision 20-08-046 directs that the Investor-Owned Utilities'

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[5] *See* RAMP Chapter 4 - Wildfire and PSPS, for additional information.

[6] *See* R.20-07-013, Assigned Commissioner's Ruling Issuing Phase II Roadmap for Comment, p. 1.

vulnerability assessments address the “key time frame” of the next 20 to 30 years, as well as the intermediate time frame of the next 10 to 20 years and the longer-term time frame of the next 30–50 years.

SCE cross-referenced climate change exposure projections with the sensitivity metrics of assets, operations and services to identify any potential significant consequences from that exposure. Any assets, operations and services that were determined to be both exposed and sensitive to an individual climate hazard were deemed to be “vulnerable” and considered for further analysis in the “At Risk” phase of the CAVA analysis. Potential climate adaptation measures are presented in the CAVA and the Climate Change Appendix of the RAMP. Further analysis and refinement to determine the feasibility and cost of potential adaptation options is expected to occur over the next year as SCE prepares its TY 2025 GRC Application.

2. <u>Related Factors Discussion</u>

While not quantitively included in the RAMP analyses, there are other related factors that can impact Transmission and Substation (T&S) asset failures, including wildfires, cyber-attacks, seismic events, and major physical security incidents. Additionally, T&S asset failures can lead to potential widespread outages. These related factors are briefly discussed below in Table I-1; the discussion is not intended to serve as an exhaustive exploration of the subject.

Table I-1
Related Factors Impacting Transmission and Substation Asset Failures

Related Factor	Impact Description	RAMP Chapter Discussion
Wildfires	Wildfires can potentially damage transmission and substation assets, which could lead to safety, reliability and financial consequences. This applies regardless of whether SCE's equipment is associated with the ignition.	Refer to Chapter 4 - Wildfire and PSPS for discussions on efforts SCE continues to carry out mitigation efforts to address the risk of wildfire ignitions associated with our equipment.
Cyber Attacks	An external actor defined as any outside entity (a person, organization, nation-state, etc.) that attempts to maliciously bypass SCE's cybersecurity controls to gain control over our electrical assets.	Refer to Chapter 7 - Cyber Attack for discussions on efforts SCE is undertaking to mitigate the impact of cyber-attacks on our system.
Seismic Events	A seismic event has the potential to take substation and transmission assets out of service for a potentially significant period of time.	Refer to Chapter 8 - Seismic for discussions on efforts SCE is undertaking to mitigate the risk of seismic events on our assets.
Physical Security Incidents	Security breaches at our transmission and substation assets could lead to an adversary taking control of our electric system.	Refer to Chapter 11 - Major Physical Security Incident for discussions on efforts SCE is undertaking to mitigate the risk of physical security incidents in connection with our facilities and electric assets.
Widespread Outages	Equipment failure of substation and transmission assets could lead to a potential widespread outage.	Refer to Appendix E - Widespread Outage for discussions on efforts SCE is undertaking to mitigate the impact that transmission and substation assets may have in creating a widespread outage.

B. Description of SCE's Electrical System

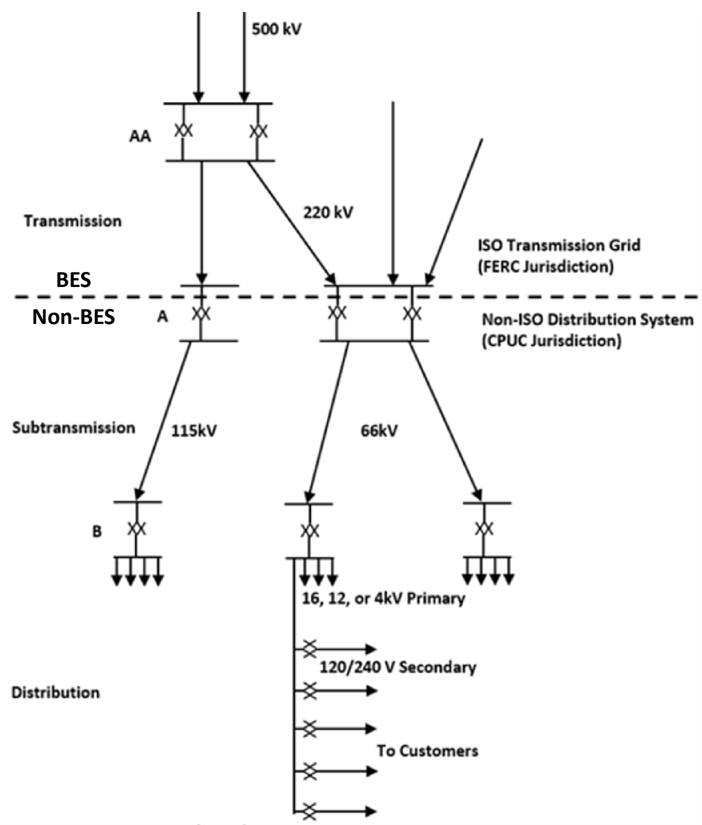
The Bulk Electric System (BES) consists of electric facilities and control systems needed to operate an interconnected electric transmission network. In general, SCE's portion of the BES includes all transmission lines operating at 220 kV or higher and all substation facilities operating at 220 kV or higher. These facilities fall under Federal Energy Regulatory Commission (FERC) jurisdiction, are subject to North American Electric Reliability Corporation (NERC) Reliability Standards,[7] and are under the operational control of the CAISO.

[7] The U.S. Energy Policy Act (EPA) of 2005 authorized the creation of an Electric Reliability Organization (ERO). The EPA of 2005 was triggered in part by concerns generated by the August 2003 blackout that affected 40 million people in the Midwestern and Northeastern United States and 10 million people in eastern

(*Continued*)

The system of facilities used in SCE's local distribution of electric energy are referred to as "local distribution" facilities and are not part of the BES. In general, SCE's local distribution facilities include sub-transmission lines typically operating at 66 kV or 115 kV, substation facilities typically operating at 66 kV or 115 kV, and distribution lines and substation facilities operating at voltages below 66 kV.[8] SCE's non-BES facilities fall under the CPUC's jurisdiction, with SCE exercising operational control. A simplified overview of SCE's electric system, showing the distinction between BES and non-BES facilities, is shown in Figure I-1 below.

Figure I-1
SCE's Electric System (BES and non-BES facilities)



Canada. On July 20, 2006, the FERC issued an order in Docket No. RR06-1-000 certifying the NERC as the nation's ERO under Section 215 of the Federal Power Act. As the ERO, NERC has been granted the authority to develop and enforce reliability standards applicable to all owners, operators, and users of the bulk power system, rather than relying on voluntary compliance.

8 SCE does have certain sub-transmission lines and substation assets below 220 kV that are also BES facilities. These are the exception rather than the rule; the vast majority of SCE's sub-transmission system is classified as non-BES.

II.

Risk Definition and Scope

There are two general types of direct safety risks related to transmission lines, sub-transmission lines, and substation assets: (1) Contact with energized equipment, where a person and/or debris makes contact with the system while the system is intact and operating normally; and (2) Equipment and/or structure failure where a person is injured as a result of asset failure. In this Appendix, SCE provides examples of potential safety risks associated with these assets, including:

- Transmission Line Clearances;
- Transmission Conductor and/or Conductor Attachment Failure;
- Transmission Line Structure Failure;
- Substation Transformer Failure;
- Substation Circuit Breaker Failure;
- Relays, Protection, and Control Replacements; and
- Substation Switch Racks Failure;

Table II-2
SCE 2022 RAMP Transmission and Substation Asset Failure Risks and SCE's Risk Remediation Activities[9]

#	Transmission and Substation Asset Failure Risk	SCE Risk Remediation Activities			
1	**Transmission Line Clearances - Example of contact with energized equipment**	Transmission Line Rating Remediation (TLRR)	Transmission Line Patrols	Transmission Routine Vegetation Management	
2	**Transmission Conductor and/or Conductor Attachment Failure - Example of equipment and/or structure failure**	Transmission Capital Maintenance	Transmission O&M Maintenance	Insulator Washing	
3	**Transmission Line Structure Failure - Example of equipment and/ or structure failure**	Transmission Capital Maintenance	Tower Corrosion Program	Transmission O&M Maintenance	Transmission Underground Structure Inspection
4	**Substation Transformer Failure - Example of equipment and/or structure failure**	Substation Equipment Replacement Program	Substation Transformer Bank Replacement Program	Transformer Inspections and Maintenance	
5	**Substation Circuit Breaker Failure - Example of equipment and/or structure failure**	Circuit Breaker Replacement	Substation Equipment Replacement Program	Circuit Breaker Inspections and Maintenance	
6	**Relays, Protection, and Control Replacements - Example of equipment and/or structure failure**	Relays, Protection and Control Replacements	Relay Inspections and Maintenance		
7	**Substation Switch Racks Failure - Example of equipment and/or structure failure**	Substation Switch Rack Rebuild			

A. Transmission Line Clearances

1. Risk Description

Transmission or sub-transmission line clearance discrepancies represent a set of risks leading to General Order (GO) 95 clearance violations (e.g., vegetation, phase-to-phase, phase-to-foreign object, phase-to-ground, etc.). This risk is an example of contact with energized equipment.

A discrepancy is any condition found in the field requiring remediation in order to meet GO 95 requirements during peak load conditions. The discrepancies have been prioritized based on the following criteria: line sag when operating at or below 275 degrees Fahrenheit; the potential risk to public safety; and system reliability.

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[9] This table is not an exhaustive list of all assets and equipment associated with mitigating Transmission and Substation asset failures. For example, substations require a properly calculated and configured Battery System. Each time stations upgrade from electromechanical relays or receive a full automation upgrade, a desktop load calculation analysis is performed on the existing Battery System to determine whether it should be upgraded.

2. **Risk Remediation Activities**

SCE has multiple programs in place to remediate transmission line or sub-transmission line discrepancies that can trigger GO 95 clearance violations. This includes remediation to replace towers, poles, and conductors, raising transmission towers, clearing brush, replacing insulators, adding or lowering cross arms, removing slack, guy to conductor clearances, relocating lines and other efforts.

a) **Transmission Line Rating Remediation (TLRR)**

SCE conducted a Light Detection and Ranging (LiDAR) study to identify field conditions associated with transmission circuits to assess any potential violation of GO 95. This study was launched in 2006. Initial results were provided to NERC in 2011. NERC and the Western Electricity Coordinating Council (WECC) then requested that SCE add 115 kV radial data to its LiDAR analysis. The studies of the radial lines were completed and conveyed to NERC in 2013. SCE's total number of identified discrepancies is 11,783. As agreed to by SCE and NERC/WECC, Bulk Electric System (BES) discrepancies are to be remediated by 2025 and radial facility discrepancies are to be remediated by 2030.[10]

Through the fourth quarter of 2021, the TLRR program has remediated 2,710 discrepancies, cleared 1,102 discrepancies as having no potential clearance violation by SCE engineering (meaning that reassessment determined that the line clearance is within acceptable engineering tolerances), and had 655 discrepancies cleared by other programs or projects. This leaves 7,316 of the 11,783 discrepancies to be remediated. Initially, the study prioritized the discrepancies into six levels, and the focus was to remediate in order of highest priority. Currently, all discrepancies are evaluated on an entire circuit basis, to allow for a holistic and effective remediation strategy.

As discrepancies are reviewed for scoping, remediation work is classified as an operations & maintenance (O&M) or capital project based on established capitalization rules. Typically, O&M remediation work includes activities such as re-tensioning circuits, re-framing towers, and grading the land under a transmission line. Capital remediation work includes activities such as

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10 SCE will provide an update on the projected completion timeline in the *2022 2nd Quarter Update of Southern California Edison's Transmission Line Rating Remediations Program*.

replacing towers and poles, raising existing towers and points of connection, and re-conductoring existing conductors.

b) Transmission Line Patrols

SCE's overhead transmission lines, along with the structures supporting the lines, must be routinely patrolled, and inspected to detect any problems that may compromise the integrity of the structures or impede the transmission of electricity. These activities are performed on a predetermined schedule to comply with the requirements of GO 165. The patrols and inspections occur annually, and involve inspecting every structure and its related components, the lines in between the structures, and the rights-of-way. Lines that run through densely populated urban areas or rugged rural areas facing severe weather or environmental conditions (e.g., high winds, coastal areas exposed to salt, etc.) are typically inspected more frequently. Inspections are also performed after unplanned events, such as extreme weather, fires, and equipment malfunctions.[11]

Inspectors document any discrepancies found during the inspections, determine their priority levels, and assign a timeframe for corrective actions based on construction and compliance standards. SCE follows a three-priority rating system that follows the requirements outlined in Rule 18 of GO 95:

- A Priority 1 discrepancy is an immediate public safety/system reliability hazard that is required to be made safe within 24 hours and remedied within 72 hours.
- A Priority 2 discrepancy is one that is required to be addressed within 6 months to 3 years, depending on the high-fire tier designation of the asset. If the asset is located within high-fire tier 3, then it will be required to be addressed within six months. If the asset is located within high-fire tier 2, then it will be required to be addressed within 12 months. Non-high-fire findings are required to be addressed within 3 years.

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[11] Transmission Line Patrols are also conducted before, during, and after PSPS events. *See* Chapter 4 - Wildfire and PSPS for additional details.

- A Priority 3 discrepancy is addressed as opportunity maintenance that is performed when other work is performed on or near that particular asset. As a result of an update to Rule 18 of GO 95, overhead Priority 3 discrepancies found after June 2019 are required to be addressed within 60 months.[12]

In addition to the line patrols performed in compliance with CPUC GO 165, SCE also conducts enhanced inspections of certain high-risk, High Fire Risk Area (HFRA) structures as part of its Wildfire Mitigation Plan program. These enhanced inspections include ground and aerial reviews to provide a 360-degree view of the asset. In addition, SCE also conducts Corona[13] and Infrared Scanning[14] on certain high-risk, HFRA circuits (again, as part of its Wildfire Mitigation Plan program). Corona and infrared technologies allow SCE to detect anomalies that are not apparent during a visual-only inspection.

c) Transmission Routine Vegetation Management

SCE performs Routine Vegetation Management activities to maintain clearances around poles and equipment on the distribution and transmission systems. We do so in order to comply with regulatory requirements, meet Commission recommendations, and support overall reliability. The scope of this work is driven by GO 95, Rule 35, PRC 4292, 4293 and heavily governed by FAC-003-4, which is enforced by FERC, NERC, and WECC for transmission lines under their jurisdiction. This program is designed to manage and prevent encroachments into the recommended vegetation clearance distance.

The vegetation maintenance in proximity to Transmission assets closely aligns with the work processes described within Distribution Routine Vegetation Management. One differentiating factor between Transmission and Distribution lines is that Transmission lines have

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[12] *See* D.18-05-042 for the decision to amend Rule 18 of GO 95 requiring Priority 3 maintenance items to be corrected within 60 months effective June 30, 2019.

[13] Corona scanning is mainly performed for purposes of identifying broken conductor strands and hairline cracks within the insulator connection points on the bells.

[14] Infrared (IR) scanning is performed in conjunction with Corona scans. The IR scan detects temperature differences and heat signatures of components, which may indicate problems not visible to the naked eye that could result in potential component/conductor failure.

differing conductor thermal rating and conductor clearance requirements. Transmission conductors are typically larger than Distribution conductors and can carry more electrical load. The combination of varying Transmission conductor operating conditions (wind, temperature, load) has a dynamic effect on the conductor's behavior – i.e., conductor sag and movement (sway). Lines can sag from high load and hot weather, and lines can sway in high winds. This sag and sway movement is commonly referred to as "conductor dynamics." Therefore, SCE's program considers conductor dynamics when defining the location from which minimum clearance needs to be maintained. Consistent with recommended guidance in D.17-12-024, SCE has expanded the standard for clearance distance in high fire areas at the time of maintenance. The clearance distance in High Fire Areas has been expanded from 10 to 30 feet for power lines 115 kV and above.

SCE utilizes light detection and ranging technology (LiDAR) to help ensure that Right-of-Way clearances fully account for conductor dynamics. LiDAR is a surveying method that measures the distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor. Differences in laser return times are then used to make digital three-dimensional representations of field conditions at the time of survey. The data is then modeled against engineering information to show the maximum sag and sway of that line and indicate where vegetation should be present in relation to those points. SCE plans to conduct LiDAR inspections on bulk and sub-transmission conductor miles in HFRA to help maintain minimum clearance distances.[15]

B. Transmission Conductor and/or Conductor Attachment Failure

1. Risk Description

Transmission line or sub-transmission line conductor and/or conductor attachment failure can lead to public injuries or fatalities. This risk is an example of equipment and/or structural failure.

As transmission and sub-transmission conductors, splices, insulators, and associated hardware age and are polluted, they risk failing. The aging and at-risk of failing conductors are vulnerable to the stresses caused by circuit relays and other environmental factors. This may result in a

[15] *See* SCE's 2020-2022 WMP, pp. 412-414.

failure and can cause conductor to fall to the ground, leading to potential wildfires, personal property damage, or third-party personal contact. These failures can also impact the integrity of the BES system, as well as the reliability of service to our customers.

2. Risk Remediation Activities

SCE has multiple programs in place to remediate aging conductor and conductor attachment (e.g., insulators, clamps, splices, etc.) risks. SCE replaces aging infrastructure on an annual basis within the Transmission Infrastructure Replacement program. Replacements are prioritized based on age, wire size, deterioration identified through inspections, and documented interruptions.

a) Transmission Capital Maintenance

Transmission Capital Maintenance includes the costs to remove, replace, and retire assets on a planned or reactive basis. Planned transmission capital maintenance is driven by regular equipment maintenance cycles; maintenance work identified and prioritized through overhead and underground inspection programs; maintenance identified through observations by field personnel; and other activities. These activities are commonly referred to as grid capital maintenance and small civil work.

Some activities can result in projects or programs to proactively replace obsolete or aging equipment at risk of failure and structures to address emergent issues and maintain safety and reliability of the grid. These larger, bundled programs are managed under SCE's infrastructure replacement program, which is part of this work area.

Reactive (i.e., breakdown) replacements are initiated when equipment fails in-service, equipment failure is imminent, or possible safety issues are identified. Equipment identified as requiring replacement must be replaced in a timely manner because transmission equipment failures may lead to prolonged outages or unsafe operating conditions. Reactive maintenance also includes the cost to address encroachment violations and fencing.

Transmission Capital Maintenance can include the replacement of different types of assets; thus, it can encompass pole replacements, tower replacements, conductor replacements and the replacement of other major equipment items (e.g., switches) on the structure (pole or tower).

While many items can impact conductor failure risk, the most direct impact this work has on conductor failure would be associated with the proactive and reactive replacement of conductor.

b) Transmission O&M Maintenance

This activity includes performing repairs on transmission line equipment and structures, such as poles, towers, conductors, and their components, including FAA tower lighting and marker balls. Maintenance work on the transmission system can consist of both proactive maintenance identified during regular inspections or reactive maintenance needed as a result of unplanned events.

Proactive maintenance is performed based on inspection results and analysis of issues found in the field. The maintenance is executed based on SCE's three-priority rating system.[16] These types of proactive activities help maintain transmission equipment, reduce outages caused by failed equipment, and allow for greater efficiency in planning work. Reactive maintenance is performed when equipment fails in service due to factors such as equipment degradation, weather, animal intrusion, and/or damage caused by a third party.

The Transmission O&M Maintenance work mainly reduces the risk of conductor failure. It does so through repairing conductors and repairing or replacing conductor components and attachments, including insulators, clamps and crossarms.

c) Insulator Washing

This program requires a visual inspection of a circuit for contamination, often indicated by arcing or buzzing. If zero or minimal contamination is present, the circuit will continue to be monitored. If excessive contamination is present, the circuit must be washed. Excessive contamination on an insulator reduces its ability to insulate the energized line from the grounded support structure. This can lead to lines short circuiting, resulting in a fault. Typically, beach areas with high salt levels and high traffic volume require more frequent washing than a desert area with drier air and less exhaust from traffic.

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[16] The three-priority system is discussed above in the Transmission Line Patrols section.

Insulator washing is performed by spraying high-pressure ionized water onto insulators to remove contaminants such as salt, dirt, or automobile exhaust. The term “hot-washing” refers to the washing of energized lines, while “cold-washing” refers to the washing of de-energized lines. Hot-washing is the preferred and most commonly used practice, because the lines do not need to be taken out of operation. When practical, SCE uses specially equipped water trucks with a derrick and water nozzle to direct a high-pressure stream of water onto the insulators while the line remains in service. Where this is not practical, a lineman must climb the structure, and the insulators are then washed by a portable wash gun connected by a high-pressure hose to a water truck below.

C. Transmission Line Structure Failure

1. Risk Description

The failure of transmission line structures or sub-transmission line structures can lead to public injuries or fatalities. This risk is an example of equipment and/or structure failure.

Aging lattice steel structures and similar structures are at risk of failing due to corrosion, especially in coastal regions subject to marine layer or moisture source. This can present a direct safety risk to our workers and members of the public, as well as impact the reliability of our service to customers.

2. Risk Remediation Activities

SCE identifies transmission line and sub-transmission line structures that pose a risk of failing in service. SCE evaluates a range of mitigation options to address these structures, such as applying a coating to prevent further corrosion, or replace structures.

a) Transmission Capital Maintenance

Transmission Capital Maintenance includes the costs to remove, replace, and retire assets on a planned or reactive basis. Planned transmission capital maintenance is driven by regular equipment maintenance cycles; maintenance work identified and prioritized through overhead and underground inspection programs; and maintenance identified through observations by field personnel and other activities. These activities are commonly referred to as grid capital maintenance and small civil work.

Some activities can result in projects or programs to proactively replace obsolete or aging equipment and structures at risk of failure to address emergent issues and maintain safety and reliability of the grid. These larger, bundled programs are managed under SCE's infrastructure replacement program.

Reactive (i.e., breakdown) replacements are initiated when equipment fails in-service, equipment failure is imminent, or possible safety issues are identified. Equipment identified as requiring replacement must be replaced in a timely manner because transmission equipment failures may lead to prolonged outages or unsafe operating conditions. Reactive maintenance also includes the cost to address encroachment violations and fencing.

Transmission Capital Maintenance can include replacing different types of assets. This encompasses pole replacements, tower replacements, conductor replacements and the replacement of other major equipment items (e.g., switches) on the structure (pole or tower). While many items can impact conductor failure risk, the most direct impact this work has on conductor failure is associated with the proactive and reactive replacement of conductor.

b) Transmission O&M Maintenance

This activity includes performing repairs on transmission line equipment and structures, such as poles, towers, conductors, and their components, including FAA tower lighting and marker balls. Maintenance work on the transmission system can consist of proactive maintenance identified during regular inspections, or reactive maintenance due to unplanned events.

Proactive maintenance is performed based on inspection results and analysis of issues found in the field and is executed based on SCE's three-priority rating system (discussed above). These types of proactive activities help maintain transmission equipment, reduce outages caused by failed equipment, and allow greater efficiency in planning work. Reactive maintenance is performed when equipment fails in service either due to factors such as equipment degradation, weather, animal intrusion, third-party damage, and/or after extreme weather.

The Transmission O&M Maintenance work that most directly reduced risk associated with conductor failure is the repair of conductors and repair or replacement of conductor components and attachments, including insulators, clamps and crossarms.

c) <u>Transmission Corrosion Program</u>

Transmission tower failure presents a public safety and reliability risk. Transmission steel structures are among SCE's largest and most important assets. SCE has approximately 27,000 transmission steel structures across SCE's service territory including out-of-state inter-ties. These structures and lattice towers are mostly comprised of galvanized, painted steel and typically range from 50 to 300 feet in height. Many of these structures were built between 1950 and 1990, while others in the system even predate 1950. In 2022, 93 percent of SCE's tower portfolio will be 30 years or older and subject to some level of corrosion. Corrosion has been observed particularly in towers where the protective paint coating has deteriorated. Once a galvanized tower begins to corrode, the corrosion advances more quickly.

While some towers are identified for remediation, SCE commenced assessments in 2020 and started testing programs in 2022 to identify the total scope of remediation work. These assessments and tests will be above and below ground. Without mitigation, especially in more extreme weather areas, SCE's lattice towers will continue to corrode.

d) <u>Transmission Underground Structure Inspections</u>

Like overhead assets, SCE's underground lines and vaults require routine inspections to detect and remedy any degradation that may lead to safety hazards or system reliability issues. Inspections of the underground components (which include vaults, cable, splices, and shield arrestors) are performed at least once every three years in compliance with CPUC GO 165. Similar to overhead inspections, emergent inspections to assess component or structural damage are performed after unplanned events. Such unplanned events include severe weather, lightning, fires, equipment malfunction, and other incidents that may have caused circuit interruption or damage.

This activity also includes SCE's Underground Service Alert (USA) location requests. California state law requires excavators to contact DigAlert prior to breaking ground.

Both excavators and utilities have responsibilities pursuant to this law. Excavators must delineate or pre-mark their work area, and contact the utility within two working days prior to excavating. Utilities must mark or locate their lines onsite within two working days of notification.

D. Substation Transformer Failure

1. Risk Description

Substation Transformer failure represents the catastrophic failure of substation transformers, which can lead to public and/or worker injuries/fatalities. It can also impact BES system integrity and affect service reliability to our customers. This risk is an example of equipment and/or structure failure.

Transformers are one of the most critical pieces of equipment in a substation. In general, AA Bank Transformers are used to lower transmission voltages down to sub-transmission voltages (please refer to Figure I-1). A-Bank Transformers are used to lower sub-transmission voltages down to distribution voltages, where a majority of customers draw their power. When a substation transformer fails, it may disturb the power flow to the system, causing a reliability consequence. In some cases, a transformer failure can be catastrophic in nature. If there are personnel near the transformer when a catastrophic failure occurs, those individuals are exposed to greater safety risks. In addition, catastrophic transformer failures can also damage other substation equipment and may cause widespread electrical service interruptions.

2. Risk Remediation Activities

The Substation Infrastructure Replacement (Sub IR) program proactively prioritizes replacing transformers based on health condition and end of life to prevent operational failure; this is particularly important due to the high criticality of the asset class to grid reliability. This proactive approach to transformer replacement before run-to-failure incidents not only provides grid reliability and safety benefits, but also reduces equipment and labor costs by leveraging SCE’s ability to maximize resources (thereby benefitting our customers).

a) <u>Substation Transformer Bank Replacement Program</u>

Power transformers are apparatus which transfer electrical energy from one electrical circuit to another through the phenomenon of electromagnetic induction. Substation transformers are major pieces of equipment used to either: (1) increase electricity voltage to reduce energy losses during its transmission over long distances; or (2) reduce electricity voltage to a more manageable and compatible voltage for customer usage.

The Sub IR program identifies and proactively prioritizes replacing transformers primarily based on health conditions and other factors such as age and criticality to grid reliability. Transformers are found in transmission and distribution substations with voltages ranging from 500 kV to 2.4 kV. An in-service failure of a transformer can be catastrophic and can impact grid reliability and the safety of SCE employees and customers. While a certain amount of redundancy is built into the transmission, sub-transmission and distribution systems, an in-service failure of one piece of equipment would place that system into an "N-1" condition, which signifies that a second failure or system disturbance could cause a massive blackout affecting significantly large areas. The consequences of such a blackout are so severe that SCE must take every reasonable precaution to prevent it.

Transformers are essential and critical components of the power grid. Without transformers, the electric grid would not exist as it is known today. Transformers vary in complexity based on the level of voltage they can transform, and are some of the most expensive assets on the electrical grid. A substation transformer failure can result in a prolonged, widespread outage affecting many customers. Substantial costs to replace the transformer may be required. The failure may pose a significant public safety risk.

The consequences of an in-service failure of transformers can be significant. Transformers typically supply power to multiple distribution circuits, and an in-service failure could cause an outage to thousands of customers. Although infrequent, in-service failures of transformers can be violent. These transformers are oil-filled; catastrophic failures and ensuing fires can endanger the safety of SCE employees and the operability of nearby equipment.

Inspections help identify many incipient failures. However, inspections cannot prevent all failures, due to the speed at which failure mechanisms can arise and progress. Therefore, planned preemptive replacement (under stable and controlled conditions) of transformers that are approaching the end of their service lives is a prudent and responsible action to minimize the risk of in-service failures.

b) <u>Transformer Inspections and Maintenance</u>

Routine maintenance, diagnostic testing, and proper operation of transformers are of paramount importance in preventing in-service failures and prolonging the operational life of a complex and expensive asset.

Substation transformers consist of many components: main tank, bushings, cooling radiators, and fans. In approximately 20 percent of our transformers, a Load Tap Changer (LTC) is also present. Maintenance and inspection activities carried out on transformers include: (a) a detailed visual inspection of the transformer and ancillary equipment; and (b) transformer oil testing for Dissolved Gas Analysis (DGA). Each transformer equipped with an LTC will have the mechanism serviced during the visual inspection. The LTC receives a DGA or an Oil Tap Changer Analysis (OTA), depending on its configuration. Some LTC configurations do not facilitate a DGA or an OTA test. In such configurations, an internal inspection of the device is performed on a periodic basis.

High-grade mineral oil is used in transformers to perform two functions: cooling and insulation. Heat and moisture can degrade the transformer and the oil, and the DGA test is performed to monitor this degradation. The OTA test performed on the LTC comprises a DGA and additional tests to determine the health of the LTC oil, contacts, and associated parts immersed in the oil. These additional tests include particulate analysis of metals and other materials found in the oil. Based on the results of the DGA or OTA tests and inspections, further inspections (including internal inspections) and diagnostic testing might be necessary to assess and repair the transformer and its ancillary devices, such as bushings, radiators, conservator tanks, and associated components.

Repairs can range from minor to major. The cost associated with these repairs can vary from several hundred dollars up to and exceeding tens of thousand dollars. An example of a minor repair would be replacing a cooling fan. A major repair would be an active leak on a transformer, which requires the transformer oil to be drained and processed, all gaskets replaced, and the transformer refilled. These repairs may include replacing parts and ancillary equipment. Diagnostic tests are also conducted after routine or emergency field repairs to determine whether the transformer can be placed back in service. LTC Internal Inspections involve very rigorous and detailed inspections of the tap changer parts and mechanisms. These are typically performed if the results of the load tap changer mechanism maintenance or OTA warrant further investigation.

c) Transformer On-Line Dissolved Gas Analysis (DGA) Monitors & Bushings

The On-Line Dissolved Gas Analysis Monitors & Bushings actively monitors for internal breakdown/failures that could cause internal failures. DGA has been in practice for many years with AA-Bank (500/220 kV) and A-Bank (220/115 kV or 220/66 kV) transformers as part of maintenance and inspections process, SCE is piloting and evaluating expanding to B-Bank (115/33 kV) transformers.

E. Substation Circuit Breaker Failure

1. Risk Description

Substation Circuit Breaker failure represents the catastrophic failure of substation circuit breakers,[17] which can lead to public and/or worker injuries/fatalities. This risk is an example of equipment and/or structure failure.

Substation circuit breakers are protective devices that primarily function to interrupt current flow when a fault condition occurs. This prevents damage to equipment and minimizes the impact of disturbances on the system, which can under certain circumstances lead to safety impacts. Circuit breakers also provide a means to carry out routine switching operations in order to perform maintenance on substation equipment. There are two potential failure modes for circuit breakers that can result in potential safety impacts:

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[17] Catastrophic circuit breaker failure is a violent event typically accompanied by electrical arcing and either the spewing of porcelain shrapnel or a rupture of the circuit breaker tank that causes a release of the tank's insulating medium (such as oil or SF6 gas).

- Failure of circuit breaker to operate during fault event; and
- Catastrophic failure of circuit breaker during normal operation or fault event.

The failure of a circuit breaker to operate during a fault could result in longer fault durations or inadequate fault clearing. This can lead to greater damage to equipment and elevated safety risks. If a circuit breaker fails catastrophically, it could also expose nearby personnel to additional safety risks. A failing circuit breaker can make it necessary to use backup protection devices to clear faults. This increases the resulting size of electrical service interruptions and associated indirect safety risks. Some circuit breakers are identified as potentially being subjected to more fault duty than they are rated for during a fault condition. These are referred to as overstressed circuit breakers. Circuit breakers identified as overstressed are more vulnerable to the failure modes described above.

2. Risk Remediation Activities

SCE has multiple programs to mitigate risks related to circuit breaker failures. Our maintenance and inspection programs monitor and maintain circuit breaker conditions. The Sub IR program replaces aging and at-risk of failing circuit breakers on a preemptive basis before they reach the end of their usable lives. The Substation Equipment Replacement Program (SERP) replaces overstressed circuit breakers. These mitigations are intended to reduce the number of circuit breaker failures, which in turn reduces the associated reliability and safety risks.

a) Circuit Breaker Replacement

The Sub IR program takes a preemptive approach by proactively replacing equipment before they reach the end of their usable lives, in order to reduce the chances of catastrophic failures. By preemptively replacing circuit breakers when risk and reliability analysis determines that an in-service failure is likely to occur and the consequences are high, we are prudently managing the system on behalf our customers.

The Sub IR program aims to mitigate the potential safety and reliability risks of equipment failure by selecting and prioritizing assets to be replaced prior to failure. Circuit breakers are identified using a risk-informed prioritization. Reprioritization occurs as field conditions change and/or as new projects are identified to address other issues at the same substation. In some cases, coordination or bundling of projects may represent the optional solution due to engineering and/or construction resource constraints. Circuit breakers are typically replaced on a proactive basis, primarily based on health conditions and other factors (such as age, or criticality to grid reliability).

The Sub IR program sets an annual goal to identify and replace circuit breakers that are approaching the end-of-life cycle, have poor health assessment, contain parts known to be problematic or no longer available, or that can no longer be cost-effectively maintained.

b) Substation Equipment Replacement Program (SERP)

The Substation Equipment Replacement Program (SERP) evaluates the adequacy of substation terminal and system protection equipment, and proposes upgrades when deficiencies are identified. SERP identifies substations where available fault current, or short-circuit duty, exceeds equipment ratings necessary for safe and reliable service. SERP aims to mitigate the potential safety and reliability failure by proactively identifying and replacing currently overstressed circuit breakers and related equipment. If a circuit breaker is overstressed because it is sited where the available short circuit duty exceeds the nameplate short-circuit duty rating, and a fault occurs, the circuit breaker is subject to failure. The failure is likely to result in a catastrophic event, and a widespread and prolonged outage.

c) Circuit Breaker Inspections and Maintenance

Our Substation Construction and Maintenance (SC&M) program funds emergent replacement equipment (substation equipment replacement), reactive replacement due to imminent replacement being needed, and one-for-one replacement. Circuit breaker replacements vary annually based on the CB failure rate in the system. When feasible and applicable, SC&M will repair circuit breakers with spare parts to reduce the cost to our customers. SC&M will also adjust, lubricate, and analyze circuit breaker performance to support system reliability. Circuit breaker repairs are limited to emergent situations and to substations where a replacement circuit breaker is not available for that particular substation design. For example, any replacement parts for circuit breakers in indoor or cubical type substations are purchased from an approved vendor. Repairs are the first approach, but depending on the severity of the issue, repairs are not always an option.

d) Circuit Breaker On-Line Monitors (CBOLM)

SCE is piloting and evaluating the benefits of installing Circuit Breaker On-Line Monitors (CBOLM) to increase the ability to collect and analyze circuit breaker data during real-time fault operations. This collection of real-time data can be useful in connection with future preventative maintenance measures.

F. Relays, Protection, and Control Replacements

1. Risk Description

SCE uses relays in the protection and control system, primarily to detect abnormal conditions on the power system. These abnormal conditions include faults (or short circuits), overloads, or major equipment failures. Through relays, we can then initiate actions to isolate or correct these abnormalities. Under abnormal conditions, if the power system is without protective relaying schemes, the following potential risks may occur: (1) equipment damage, (2) personnel injury or fatality, (3) ignition of fires, and (4) unplanned outages.

The main goals of the substation protection and control system are to minimize damage, help ensure safety, and improve system reliability (by minimizing outage impacts). Relay failure by itself would not necessarily cause any adverse impacts directly on SCE system; rather, it would result in a loss of the capability to detect faults or adverse conditions and the inability to minimize the risks during a concurrent abnormal system incident.

2. Risk Remediation Activities

a) Substation Relays, Protection, and Control Replacement program

The likelihood of a simultaneous occurrence of relay failure and system/equipment malfunction is rather minimal, since the two random incidents must happen at the same time and on the same circuit. However, if the concurrent event were to happen, the risk impact could be significant.

Due to this concern, SCE Substation Relays, Protection, and Control Replacement program identifies and proactively replaces substation protective relays, control, automation, monitoring and event recording equipment. The program is designed to reduce the potential risk impact, address equipment obsolescence, meet compliance requirements, and improve functionality. The program includes the following:

- Bulk and Non-Bulk Relay Replacement, which replaces obsolete relaying schemes (electromechanical, solid state relays and first-generation microprocessor-based relays);
- Substation Automation Replacement, which replaces obsolete/end-of-life control and automation systems (Remote Terminal Units and Programable Logic Controllers) and first-generation Substation Automation Systems; and
- Digital Fault Recorder Replacement.

In addition, for 220 kV and above systems, the equipment or assets are too valuable to solely rely on one relay or relay system. Thus, another layer of protection has been added to provide redundancy to further reduce the probability of occurrence.

b) <u>Relay Inspections and Maintenance</u>

Proper maintenance and diagnostic testing of relays is essential to system reliability and operations. Protective relays have been described as "silent sentinels." They do not generally demonstrate their performance until a fault or other problem requires them to protect the power system. A failure or false operation of a protection system to operate as designed can result in a safety hazard to personnel, equipment damage, wide area disturbances, or unnecessary customer outages. The maintenance/testing program determines whether the performance and availability of protection systems and protective relays settings are in accordance with specifications.

SCE uses time-based maintenance to address installation and maintenance requirements for each protection asset type. SCE maintains protection relays in place. If a relay cannot be fixed in place, it is sent out for root cause analysis. To maintain certain relays, SCE does require outages.

G. Substation Switch Racks Failure

1. Risk Description

A substation switch rack is an open-air or enclosed metal-clad skeletal/structural system used to support substation assets such as disconnects, conductors, and other auxiliary equipment. Substation structures degrade over time and need to be replaced and/or upgraded. Switch rack failure represents a worker safety and reliability risk, and potentially a cascading impact on the other major substation assets such as circuit breakers and transformers.

The key drivers of switch rack failure are:

- Deteriorated condition of structures such as wood pole, lattice or pipe steel;
- Degraded cubicle switchgear due to aged equipment, deteriorated enclosure, and confined working space;
- Seismic inadequacy;
- Feasibility to support new equipment installation, such as Circuit Breaker or Transformer Replacements within the switch rack;
- Lack of required clearances that create unsafe operating conditions.

The switch racks or structure rebuilds are initially identified at the scoping job walk, typically driven by the circuit breaker replacement.

2. Risk Remediation Activities

The switch rack rebuild candidates are based on conditions found in the field during scoping job walks, as well as through various follow-up analyses, including structural and seismic analysis. At the scoping job walk, the field personnel (operations, construction, maintenance, etc.) and engineering personnel evaluate the condition of foundations, equipment, structures, and working areas/clearance to identify the need to perform a switch rack rebuild project to address the potential risk.

a) Substation Switch Rack Rebuild

For those inadequate switch rack structures, SCE develops site-specific switch rack rebuild requirements based on the field conditions identified during the pre-engineering job walk for a substation equipment replacement project. Prior to pursuing a switch rack rebuild, SCE also considers other potential solutions, including modifying a switch rack (e.g., structural modification in place or additional grading beneath a switch rack structure).

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Appendix D

Nuclear Decommissioning

Rosemead CA
May 13, 2022

Appendix D: Nuclear Decommissioning

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I.

BACKGROUND

This Appendix addresses the safety risks associated with the decommissioning of Southern California Edison's (SCE) San Onofre Nuclear Generating Station (SONGS). As discussed below, SCE mitigates these safety risks by adhering to Nuclear Regulatory Commission (NRC) radiological safety regulations and other federal and state industrial safety regulatory requirements, and establishing robust programs and procedures to ensure compliance.

During the past four years, SCE successfully eliminated two of the safety risks associated with SONGS decommissioning that we had discussed in SCE's 2018 RAMP. These two safety risks were: (1) Operational (Spent Fuel Pool Operations), and (2) Fuel Transfer Operations (FTO). As described below in Section IV, all fuel has been successfully transferred out of the spent fuel pools, and all spent fuel assemblies have been sealed into dry storage canisters and placed in the passively-cooled, robustly-secured Independent Spent Fuel Storage Installation (ISFSI).

SCE has identified four existing risks associated with SONGS decommissioning: (1) Industrial Safety, (2) Compromise of SONGS Physical Security, (3) ISFSI Operations and (4) Offsite Radioactive or Hazardous Waste Spill or Incident. In Section IV below, SCE describes these risks, and qualitatively addresses our efforts to mitigate them.

A. SONGS Location

SONGS was a three-unit nuclear generation facility located on the coast of Southern California, in San Diego County, about 62 miles southeast of Los Angeles and 51 miles northwest of San Diego. The on-shore SONGS site is located within the boundaries of Marine Corps Base Camp Pendleton under easements granted by the U.S. Department of the Navy (Navy). The offshore sites, used for seawater intake and discharge conduits related to facility operations, are utilized pursuant to lease contracts with the California State Lands Commission (CSLC).

B. Shutdown Dates

Unit 1 commenced commercial operations in 1968 and was permanently retired in 1992. Most of the onshore Unit 1 facilities were dismantled by 2009. The Unit 1 offshore conduits were partially dispositioned in 2014. All Unit 1 spent fuel was transferred from wet storage in the spent fuel pools to dry storage in the on-site ISFSI during 2003-2005. The remaining Unit 1 structures are located beneath the ISFSI and are planned to be dispositioned following the decommissioning of the ISFSI.

Units 2 and 3 commenced commercial operations in 1983 and 1984, respectively, and were permanently retired in 2013. The transfer of the Units 2 and 3 spent nuclear fuel from the pools to the ISFSI was completed in August of 2020. SCE now holds licenses from the U.S. Nuclear Regulatory Commission (NRC) under 10 C.F.R. Part 50 that authorize the possession of the SONGS facilities and licensed nuclear material (spent fuel) within a specified portion of the on-shore site, but that no longer permit power plant operations.

C. Decommissioning Governance

SCE is the majority owner of SONGS. San Diego Gas & Electric Company (SDG&E), and the City of Anaheim and the City of Riverside (the Cities), are minority participants in the ownership and/or decommissioning liability of SONGS. SCE, SDG&E, and the Cities are collectively referred to as the Participants.

On April 23, 2015, the Participants executed the SONGS Decommissioning Agreement. The Agreement designates SCE as the decommissioning agent, provides for the performance of decommissioning work, and identifies the separate rights, duties, and obligations of the Participants. The Agreement requires the Participants to restore the SONGS site in accordance with applicable federal and state regulations in an effective manner. It also requires unanimous agreement among the Participants for major decisions. Accordingly, the Participants collectively oversee the decommissioning project.

D. Decommissioning Status

In December 2016, the Participants retained SONGS Decommissioning Solutions (SDS), a joint venture between Energy Solutions and AECOM, to serve as the Decommissioning General Contractor (DGC) and perform a substantial portion of the SONGS decommissioning work scope. SDS staff has substantial experience and expertise in performing large-scale nuclear decommissioning projects similar to SONGS. SDS commenced mobilizing its SONGS decommissioning team in 2017, and has assumed the performance of many functions at the site that were previously handled by SCE.

In October 2019, the California Coastal Commission granted the Coastal Development Permit (CDP) for the onshore portion of the Units 2 and 3 decommissioning project, including the decontamination and dismantlement of the above-grade structures at SONGS to SCE and the Participants. Upon completion of successful FTO, SCE issued the Phase II Notice to Proceed to the DGC in August 2020. This Phase includes the decontamination, dismantlement, demolition, removal, and waste disposal of the entire Unit 2 and 3 site footprint to approximately 3 feet below grade, with the exception of the on-site ISFSI and its associated security facilities, as well as the switchyard area.

At the end of this period, SDS is expected to have completed all decontamination and dismantling (D&D) work necessary to obtain NRC approval to reduce the site footprint licensed under 10 C.F.R. Part 50 to the ISFSI area only, and to allow release of most of the remaining SONGS site for unrestricted future use.

II.

NRC JURISDICTION AND REGULATORY FRAMEWORK

A. Jurisdiction

Under the Atomic Energy Act of 1954, the federal government exercises exclusive jurisdiction over the nuclear and radiological safety aspects of nuclear energy generation. The courts have affirmed that Congress expressly and implicitly intended to preempt state regulation pertaining to nuclear facility operations and radiological safety, including the construction, operation, and decommissioning of licensed nuclear reactor facilities. Based on both the express and implied Congressional intent, the individual states have no jurisdiction over nuclear facility operations and radiological safety matters. States may exercise their traditional authority over the need for generating capacity, the type of generating facilities to be licensed, land use, ratemaking, and the like.

B. NRC Regulatory Framework

Consistent with its pervasive regulatory authority over nuclear facility operations and radiological safety, the NRC has established a rigorous and comprehensive regulatory framework for all aspects of the nuclear facility life cycle, including facility design, licensing, construction, operation, decommissioning, radioactive waste transportation and disposal, and final site decontamination and restoration. The paramount priority of the NRC framework is to ensure all aspects of safety and regulation are initiated and upheld. This framework encompasses both operating nuclear facilities and decommissioned facilities. The intent is to protect public health and safety, promote security of radioactive materials, and protect the environment.

As a prerequisite to NRC licensing, each facility develops a comprehensive safety analysis report that evaluates all potential risks of facility operations and establishes risk mitigation strategies. Each facility has NRC-approved technical specifications that set forth specific parameters within which the facility must be operated. The NRC license is conditional based on the facility's compliance with all such parameters.

The NRC oversees decommissioning activities and ISFSI operations through various means, including the use of on-site inspectors and a robust enforcement program. Enforcement sanctions may include notices of violation, monetary fines, or orders to modify, suspend, or revoke a license, or require specific actions because of a public health issue.

The NRC license for each nuclear facility remains in effect until the facility is decontaminated and decommissioned, and all federal requirements for license termination have been fulfilled by the licensee and verified by the NRC. Thus, SONGS will remain subject to the NRC's jurisdiction and regulatory framework until decommissioning and license termination are completed. NRC license termination is currently forecast to be completed by 2053.

III.

SONGS SAFETY PROGRAMS

Safety is paramount at SONGS, and represents an SCE core value. SCE expects all workers at SONGS, whether utility employees or contractors, to perform all work safely and in accordance with NRC and other regulatory requirements. SCE goes to great lengths to ensure that all workers are properly trained and equipped to perform all SONGS decommissioning work safely. Because SCE contracted with SDS to act as the DGC, SDS is primarily responsible for safety program implementation. Nevertheless, as the NRC license holder, SCE bears the ultimate responsibility for safety at SONGS. SCE, therefore, performs proactive oversight of the SONGS safety programs.

A. Decommissioning General Contractor (DGC) Safety Program

As the DGC, SDS has implemented a comprehensive industrial safety and radiation protection program that meets all NRC and other regulatory requirements. All other contractors are also required to implement robust and comprehensive safety programs associated with their work on the SONGS decommissioning project.

SDS is committed to maintaining a strong safety culture throughout SONGS decommissioning. This is accomplished by creating and sustaining a work environment that values the following:

- Having every employee leave the workplace unhurt;
- Using work behaviors and practices that uncompromisingly protect the safety of everyone;
- Caring for the safety of each other; and
- Stopping work anytime unsafe conditions or behaviors are observed until the job can be completed safely.

SDS strives to achieve the continuous commitment and dedication by all workers to follow these values, in order to make sure that a safe workplace is established and that the safest work behaviors are used to prevent hazardous conditions and injuries. SDS trains all workers, as applicable, on using a variety of human performance and safety awareness tools. These tools include:

(1) Completing meticulous pre-job planning, pre-job briefs, and safety observations during work; and

(2) Requiring appropriate safety equipment and personal protective equipment, personal situational awareness and attention to detail, procedural compliance, and three-way communication throughout each activity. SDS insists upon the use of these tools, and monitors adherence through a variety of human-performance/safety metrics. In addition, every worker is authorized to stop work and obtain clarification any time a question arises regarding the safe performance of any job. SDS also employs a corrective action program that performs in-depth evaluations of all plant incidents or accidents.

B. SCE Oversight of Safety

As noted above, SCE serves as decommissioning agent on behalf of the Participants. In doing so, SCE actively oversees the performance of all decommissioning activities, whether by utility personnel or its contractors. SCE's safety oversight helps ensure that: (1) each decommissioning work scope is performed safely and in accordance with site procedures; (2) near-misses and other lessons learned are reported promptly to the SONGS Vice President and Chief Nuclear Officer and senior leadership team; and (3) the site is restored to a radiologically safe condition suitable for future uses.

For example, if a scope of work involves demolishing, removing, and disposing of a particular building and its foundations, SCE's oversight helps ensure that the building and foundations are removed safely and in their entirety. It also helps ensure that the disposal of all associated waste materials is performed completely and documented properly, in accordance with NRC and other regulatory requirements. Through its active oversight, SCE will stop decommissioning work if it is not being done safely in accordance with procedural and regulatory requirements.

As the decommissioning agent for the Participants, SCE is ultimately responsible for making sure that that there are no remaining impediments to terminating the NRC licenses as well as terminating the site leases and grants of easement after all decommissioning and final site restoration work is completed.

SCE has instituted several oversight mechanisms to help ensure that work proceeds safely at SONGS, and to monitor and report on safety performance. SCE's SONGS Safety group uses a focused, risk-based observation program.[1] The risk-based observation program includes qualified safety inspectors that personally observe the performance of the decommissioning activities and provide real-time safety recommendations as needed. In addition, the SONGS Safety group continually monitors safety performance, including near-misses and other lessons learned, and provides frequent safety reports to the SONGS Vice President and Chief Nuclear Officer and senior leadership team. SONGS

[1] A risk-based observation program classifies risks based on their comparative physical and economic severities, and then allocates safety observation resources on a prioritized basis commensurate with the comparative risk levels.

safety performance is also reviewed by the Decommissioning Agent Advisor. This is an independent team of nuclear industry executives that provide objective input to SONGS leaders regarding all aspects of nuclear facility operations, including safety. SCE also employs a corrective action program that performs in-depth evaluations regarding the safety oversight of all plant incidents or accidents.

IV.

DISCUSSION OF ELIMINATED 2018 RAMP RISKS

A. Risk – Operational (Spent Fuel Pool Operations)

1. Description of Risk

In SCE's 2018 RAMP, SCE noted that all fuel that remained in the Units 2 and 3 spent fuel pools was scheduled to be removed from the pools and transferred to the SONGS ISFSI.[2] SCE explained that until the fuel is removed, the spent fuel pools and all necessary equipment would continue to operate. The primary risk resulting from spent fuel pool operations was the potential for insufficient cooling that would compromise the intended state of the spent fuel. This could have resulted from circumstances such as a seismic event[3] that damaged the spent fuel cooling system components, or a long-term power outage.

2. Closure of the Risk

As of August 2020, all spent fuel assemblies have been removed from the Units 2 and 3 spent fuel pools. The spent fuel pools are no longer needed, and are being prepared to be drained, decontaminated, and decommissioned.

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2 *See* SCE's 2018 RAMP report. Appendix A, p. A-9.

3 SCE's 2022 RAMP chapter on seismic risk does not include SONGS in its scope. Because of the successful transfer of all spent fuel to the ISFSI, and due to the robust engineering and design standards of the ISFSI required by federal law to prevent failures at nuclear facilities related to seismic events, at this time SCE does not consider any residual seismic risk remaining at SONGS to require further mitigation. For more information on this important topic, SCE respectfully directs the reader to: https://www.songscommunity.com/decomm-digest/seismic-safety-at-songs; https://www.nrc.gov/docs/ML1611/ML16118A148.pdf; and https://www.nrc.gov/docs/ML1312/ML13120A648.pdf.

B. Risk – Fuel Transfer Operations (FTO)

1. Description of Risk

In SCE's 2018 RAMP, SCE also explained that it had retained Holtec International to design, license, and construct an expansion to the ISFSI, and to transfer all Units 2 and 3 spent fuel assemblies that remained in wet storage in the spent fuel pools to dry storage in the ISFSI.

2. Closure of the Risk

As of August 2020, all spent fuel assemblies have been sealed into dry storage canisters and placed in the passively-cooled, highly-secured ISFSI.

V.

DISCUSSION OF EXISTING RISKS

A. Risk – Worker Industrial Safety

1. Description of Risk

As a large industrial facility that uses heavy equipment, energized electrical circuits, pressurized fluid systems, and hazardous chemicals, various industrial safety risks associated with these activities and materials exist at SONGS. It is imperative, therefore, that all work activities at SONGS are performed safely to avoid industrial accidents and injuries, electrical shock, and chemical exposures.

2. Mitigation of Risk

As discussed above, SCE, as the decommissioning agent, and all contractors who perform work at SONGS, are required to implement robust safety programs that meet or exceed federal and state requirements. These programs emphasize a safety-first culture and employ meticulous planning, pre-job briefs, appropriate safety equipment and personal protective equipment, personal situational awareness and attention to detail, procedural compliance, and three-way communication throughout each activity. The programs are also designed to ensure workers' exposure to radiation as low as reasonably achievable.

Additionally, as relevant safety industrial lessons occur, they are disseminated from the NRC (through electric and nuclear industry organizations) to peer operating facilities and decommissioning projects. In this way, each facility can benefit from and leverage each other's experiences. When SCE receives such notices concerning other facilities, the notices and information are shared with onsite contractors. In addition, briefings from nuclear industry organizations are provided to peer facilities, so that each facility can benefit from additional insights and perspectives concerning how the activity may be performed more safely and efficiently.

B. Risk – Worker Radiation Safety

1. Description of Risk

Although FTO is complete and all spent fuel has been safely placed in the ISFSI, substantial portions of the remaining SONGS systems, structures, and components contain varying levels of radioactivity, including the three federal classes of low level radioactive waste (LLRW) (i.e., Class A, Class B, and Class C) and greater than Class C (GTCC) waste.

2. Mitigation of Risk

SDS, the DGC, utilizes a Radiation Protection program that provides detailed procedures that comply with federal regulations and are consistent with industry best-practices to ensure that worker exposure to radioactivity is maintained as low as reasonably achievable. In addition, the SDS Radiation Protection Program provides procedures and processes to ensure the safe surveying, removal, handling, packaging, documentation, and disposal of all of decommissioning debris as appropriate for their respective radioactivity levels.

C. Risk – Compromise of SONGS Physical Security

1. Description of Risk

The current SONGS site configuration consists of three concentric areas:

(1) The SONGS Site Boundary, which includes the perimeter of the SONGS site. Industrial security is required primarily to prevent access by unauthorized personnel. Also included in this area is the SONGS Electrical Switchyard. Although SONGS no longer generates electricity, the SONGS Switchyard continues to be energized with high voltage electricity and functions as an important link in the grid between SCE and SDG&E service territories.

(2) The SONGS Industrial Area (IA), which includes the south end of the former Unit 1 site and the onshore Units 2 and 3 site. The IA is the location of the heavy industrial D&D project activities. It is where LLRW is stored, sorted, and removed from the site as part of the project scope.

(3) The ISFSI Protected Area (ISFSI PA), which is located on the north end of the former Unit 1 site, where spent fuel assemblies are stored, and GTCC waste from Units 1, 2, and 3 will be stored, monitored, and protected by SCE under NRC oversight.[4]

The main risk driver to each of these locations is the result of unaccounted-for visitors with malicious or non-malicious intent breaching a location to vandalize the site, endanger the spent fuel stored in the ISFSI, interrupt D&D activities, or explore the site without harmful intent.

In addition, SCE remains liable to remove the Unit 1 and Units 2&3 Offshore Conduits, which are located below the sea floor west of the IA on land leased to SCE by the CSLC. SCE remains liable to remove the conduits in their entirety should they become a navigation hazard or as otherwise directed by the CSLC.

2. Mitigation of Risk

The SONGS Site and IA boundaries are protected by the SDS Industrial Security Force, which continually patrols/monitors these areas pursuant to SCE's license and NRC's requirements. All workers and visitors to the IA must be authorized in advance per procedure and must continually display SONGS-issued photo identification badges. In addition, access to the SONGS Switchyard is controlled by the SDS Industrial Security Force.

The ISFSI PA boundary is protected by defense-in-depth security measures as required under NRC regulations. These measures include substantial physical barriers, state-of-the-art intrusion detection systems that are monitored continually, and around-the-clock protection by the armed SCE Nuclear Security Force.

[4] As long as nuclear fuel continues to remain on-site, and in accordance with NRC regulations (10 C.F.R. § 73.1 and 10 C.F.R. § 50.54), SONGS must maintain a security force to protect against potential radiological sabotage.

The Nuclear Security Force is comprised of highly-skilled officers who must qualify and maintain applicable NRC security qualification standards. To maintain their capability to detect and deter threats, Nuclear Security Officers participate in ongoing training exercises and must meet periodic requalification requirements. All personnel and equipment that access the ISFSI PA are subject to the following requirements: (1) personnel who have unescorted access to the ISFSI PA are subject to initial and ongoing security screening, and must complete annual retraining requirements; and (2) all vehicles and equipment are searched by Nuclear Security Officers before they are allowed to enter the ISFSI PA.

This multi-faceted approach provides an effective level of assurance against the security risks that may be encountered at SONGS. The ISFSI PA will remain in place until all spent fuel is removed from the site. This is currently forecast to occur by 2051. The SONGS Site Boundary and IA will continue to be protected by industrial security until SCE returns possession of the site to the landowner, which is currently forecast to occur by 2053. In addition, although SCE is not required to take active security measures pertaining to the SONGS Offshore Conduits, SCE would notify the CSLC if it became aware of any changed conditions that could potentially require their removal.

D. Risk – ISFSI Operations

1. Description of Risk

All spent nuclear fuel at SONGS has been transferred to the ISFSI. All spent fuel is safely stored in sealed stainless-steel multi-purpose canisters (MPCs) that are housed in reinforced concrete structures. This proven technology involves sealing spent nuclear fuel in airtight, welded steel canisters that provide both structural strength and radiation shielding, and then housing them in reinforced concrete structures that provide additional radiation shielding. Dry fuel storage involves a passive cooling system with no moving parts. Each MPC is filled with helium, an inert gas that helps with the cooling process and prevents corrosion. Radiant heat from the fuel is dissipated by air entering vents in the storage structure and circulating around the outside of the steel canister deigned for the long-term storage of used nuclear fuel, until the fuel is moved offsite to a federally licensed interim storage or permanent disposal facility.

The scope of this risk is two-fold:

(1) Air flow into and out of each canister enclosure could become compromised due to the presence of debris in the air inlets and/or outlets, potentially leading to overheating of the fuel assemblies inside the MPCs; and

(2) Chloride-induced stress corrosion cracking (SCC) initiated on the outer surfaces of the stainless steel spent fuel canisters could pose a potential challenge to the long-term service life of the MPCs.

2. Mitigation of Risk

The ISFSI and all of its components are licensed by the NRC. The SONGS ISFSI is engineered to help ensure sufficient passive air-cooling capability in accordance with NRC standards for heat transfer. All air inlets and outlets are sized to provide proper air-cooling capability, and have grating installed to prevent wildlife nesting.

In addition, SONGS personnel are assigned to perform walk-down inspections of the ISFSI at least once daily, and to visually inspect all enclosure gratings for the presence of any material that could impair air flow around the MPCs. Any findings are promptly reported so that the materials, if any, are removed as soon as possible. Furthermore, installed thermal detectors and radiation monitors are continuously observed by the SCE Nuclear Fuels group. Any unexpected increase in temperature or radiation levels is investigated immediately.

The risks associated with ISFSI operations will continue to be present until all MPCs are removed from the ISFSI. This is currently assumed to occur by 2049.

Comprehensive analysis has been performed to determine that SCC degradation is highly unlikely for SONGS MPCs; the Aging Management Program (AMP) provides an effective methodology to monitor, detect, and mitigate any MPC surface degradation. The AMP meets or exceeds the NRC requirements for inspecting and maintaining spent fuel canisters during their first 20 years of service.

The AMP consists of the following mitigation measures:

(1) Periodic visual and robotic inspections to detect potential MPC surface canister degradation and monitor any indications of degradation over time. SCE has developed high-resolution robotic monitoring capability to remotely inspect the exterior surface of in-service MPCs;

(2) Implementation of a test MPC program to allow SCE to better monitor the condition of the MPCs. The test canister does not contain spent fuel but otherwise is identical to the MPCs in the ISFSI, including a simulated heat load to reproduce the same environmental conditions as an in-service MPC. The test canister serves as a leading indicator of MPC conditions and allows for the continued refinement of inspection and repair tooling;

(3) Other ongoing inspections, including inspections of the ISFSI system and radiation monitoring; and

(4) Response and remediation plans to be implemented based on the results of the MPC inspections. As part of these plans, SCE has developed the Metallic Overlay process and demonstrated the capability to repair canisters if needed.

The residual risks associated with ISFSI operations will continue to be present until all spent fuel is moved offsite to a federally-licensed interim storage or permanent disposal facility. It is currently forecast that this will occur by 2051.

E. Risk – Offsite LLRW or Hazardous Materials Spill or Incident

1. Description of Risk

The DGC is responsible for the offsite transportation and disposal of LLRW and Hazardous Materials to appropriate waste processing and/or disposal facilities. This risk represents an event during transportation.

2. Mitigation of Risk

The DGC has implemented the following measures to ensure the safe handling and transportation of waste on the decommissioning project:

(1) Implementing a waste management program that establishes the responsibilities and requirements for managing, packaging, transporting, securing, guarding, and disposing of waste materials generated during decommissioning activities at SONGS;

(2) Establishing transportation procedures that provide direction on handling, packaging, loading, marking, labeling, placarding, inspecting, and shipping hazardous material in accordance with all applicable federal, state and local regulations. Procedures are also established for responding to emergency situations;

(3) Developing a transportation incident and emergency response plan that establishes actions and notifications to be taken in response to a possible transportation accident involving hazardous material shipments. This includes an established process for shipment contingency planning when any transport involves the possibility of unplanned condition that may impact the planned/scheduled transportation of LLRW and hazardous waste from the project site to the disposal facility;

(4) Establishing selection criteria and conducting evaluations to ensure that rail and trucking carriers comply with required registrations, licenses, and certifications with all federal, state and local regulations; and

(5) Utilizing waste shipment tracking programs that will track all shipments made to waste processing and disposal facilities.

The risks associated with offsite LLRW and hazardous materials transportation will continue to be present until Phase II D&D activities are completed (currently forecast to complete by 2028). These risks will also be present during Phase III D&D activities (currently scheduled during 2051-2053).

VI.

CONCLUSION

The decommissioning of SONGS is a major activity that SCE and its contractors will continue to perform over many years. Nuclear decommissioning projects involve both radiological safety aspects that are regulated exclusively by the federal government, and industrial safety aspects that are subject to both federal and state regulation. SCE has identified and analyzed numerous risks associated with the SONGS decommissioning project, and has established a robust safety program that adheres to NRC radiological safety regulations and federal and state industrial safety regulations. SCE also insists that all contractors performing SONGS decommissioning activities have similarly robust and compliant safety programs.

As the decommissioning agent ultimately responsible for decommissioning safety, SCE will continue to provide thorough oversight of all utility- and contractor-performed decommissioning activities throughout the duration of the project, currently forecast to be completed by 2053.

(U 338-E)

Southern California Edison Company

Risk Assessment Mitigation Phase

Appendix E

Widespread Outage

Rosemead CA
May 13, 2022

Appendix E: Widespread Outage

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I.

RISK ASSESSMENT

A. Risk Overview

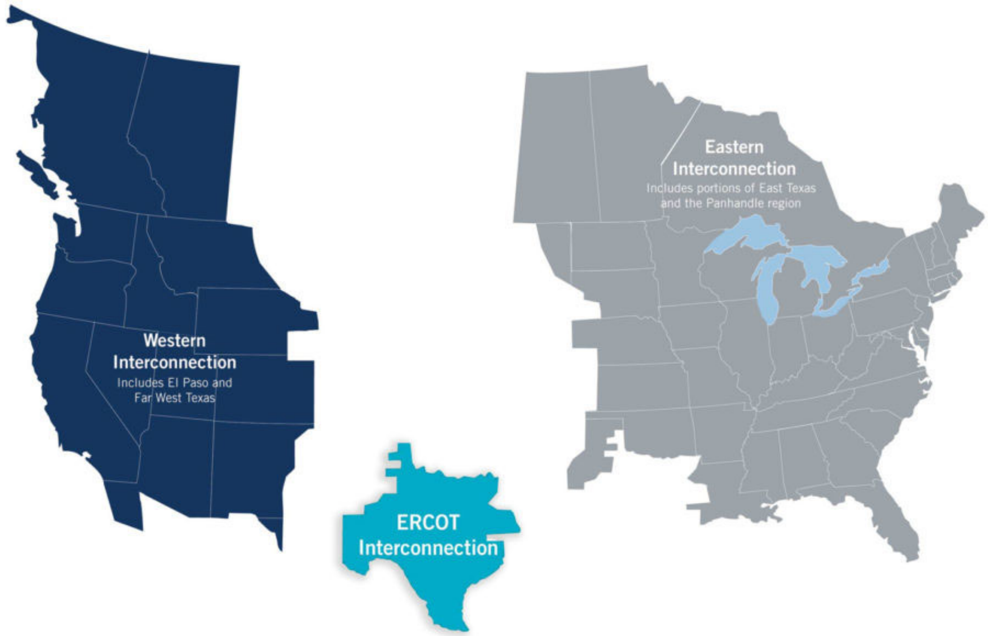
Throughout our nation, local bulk power electric grids are interconnected to form larger bulk power networks. These bulk power networks provide greater power supply capacity and make operations more economical and reliable. SCE understands that general safety-driven risks that may be broadly related to widespread outages may not ultimately be classified as a top safety risk for purposes of RAMP requirements. We appreciate the opportunity in our RAMP report to discuss this issue in the larger context of our delivery of power to our customers and the communities we serve.

In carrying out our mission to safely provide reliable, clean, and affordable energy to our customers, we work closely with our regulators (including the California Public Utilities Commission (CPUC), the Federal Energy Regulatory Commission (FERC), the California Independent System Operator (CAISO), and the North American Electric Reliability Corporation(NERC)). Despite all collective efforts, there are aspects of a widespread outage that are not within our control. Examples include cascading outages from other parts of the system interconnection, or human performance errors on the part of other utilities.

Taking reasonable measures to safeguard customers from widespread outages is core to our mission. Below, we discuss efforts we engage in to prevent widespread outages. This Appendix is not intended to serve as an exhaustive discussion of all of the steps that we take.

As shown below in Figure I-1, North America is comprised of the following three main interconnections: 1) the Eastern Interconnection, (2) the Western Interconnection, and (3) the Electric Reliability Council of Texas (ERCOT). These interconnections help keep the electric power system reliable by providing multiple routes for power to flow and to prevent interruptions in service.

Figure I-1
North American Power Grid



SCE is a part of the Western Interconnection, which extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, as well as all or portions of the fourteen Western states that are located in between. The interconnected structure of the high-voltage transmission system – typically operated between 220 and 500 kilovolts – provides a degree of redundancy. This is to help ensure that localized disturbances do not cause wider interruptions in service. However, large disturbances within neighboring areas may spread over a wide footprint of the interconnection (e.g., resulting in frequency fluctuations beyond normal operating conditions). As such, it is critical that large, rapid changes in frequency of interconnection are promptly arrested and stabilized until frequency can be fully reinstated to steady state.

Additionally, the occurrence of long-duration extreme events may produce more severe impacts resulting in system instability, uncontrolled separation, or cascading within the interconnection. Below, we describe a cascading disturbance and the resulting impact.

In September 2011, a system disturbance in the Pacific Southwest led to cascading outages and left approximately 2.7 million customers without power in parts of Arizona, Southern California, and

Baja California, Mexico.[1] Due to the loss of a single bulk power transmission line within a major transmission corridor, adverse reliability impacts cascaded throughout the region (e.g., transformers, transmission lines, and generating units tripped offline). This initiated automatic load shedding. It took the impacted entities between 6 to 12 hours to restore load, 5 to 87 hours to restore generation, and 1.5 to 13 hours to restore transmission lines tripped during the event. The two main drivers were considered to be inadequate operations planning and insufficient real-time situational awareness. The entities responsible for operating and overseeing the bulk power system were unable to prevent cascading outages even though the system is designed, and should be operated, to withstand the loss of a single bulk power transmission line.

In February 2021, an extreme winter storm event caused a massive electricity generation failure in the state of Texas, which resulted in a loss of power for more than 4.5 million homes, and over $195 billion in property damage.[2] Some of the major factors leading to the electricity blackout included the following:

- Generation technologies failed to operate at their expected electricity generation output levels;
- Demand forecasts for severe winter storms provided to be too low;
- Weather models were unable to accurately forecast the timing (i.e., within one to two days) and the severity of the extreme cold weather; and
- Planned generator outages were high, albeit not a great deal higher than what was assumed in planning scenarios.

As a result, rolling blackouts turned into persistent days-long electrical outages affecting millions of customers connected to the ERCOT grid.

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1 https://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

2 https://energy.utexas.edu/ercot-blackout-2021.

B. Risk Definition and Analysis

For purposes of this discussion, SCE defines the term Widespread Outage as a single or series of planned or unplanned events that lead to a major electrical system outage. As indicated in SCE's pre-RAMP workshop, the Enterprise Register Risk (ERR) Widespread Outage consequences are encompassed in the Cyber Attack and Catastrophic Earthquake (Seismic) risk analyses. However, recent examples, as discussed above in Section I.A, were weather-related and occurred as a result of system cascading disturbance. Other potential drivers of a widespread outage are discussed below in Section I.C and in Table II-1.

SCE continues to work with stakeholders, CAISO and other state/federal agencies to manage and mitigate this risk as described in Section II below. Furthermore, a part of SCE's core mission in complying with applicable NERC Reliability Standards is to maintain or improve transmission system reliability and ensure secure and reliable operation of the electric grid.

C. Drivers and Related Factors

When examining the potential drivers of a Widespread Outage, SCE looked at data from U.S. Department of Energy's (DOE) Electric Emergency Incident and Disturbance Report (OE-417).[3] The information in the report is compiled from utilities across the country. Whenever an electrical incident or disturbance is sufficiently large enough to cross certain reporting thresholds, electric utilities must meet reporting and other requirements to assist the DOE in fulfilling its overall national security and other energy emergency management responsibilities.[4] Based on reviewing disturbances that were reported within the Western Interconnection region from 2011 to 2020, SCE found the following six key drivers could lead to a Widespread Outage:

1. Climate, natural disasters, and weather, such as extreme heat and wildfires, could lead to a Widespread Outage by overwhelming the electric grid's ability to maintain adequacy of supply. Additionally, acute events (e.g., wildfires) and chronic stressors (e.g., extreme temperatures) impact

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[3] For additional information and detail on these reports, please refer to https://www.oe.netl.doe.gov/OE417_annual_summary.aspx.

[4] https://www.oe.netl.doe.gov/oe417.aspx.

operating performance and put grid equipment under increased stress. The changing climate could lead to direct impacts to the grid, including diminished performance, reliability, and lifespan of assets due to harsher conditions, and catastrophic events that will tax or damage equipment. On the supply side, impacts could include long-term impact to solar and wind resources due to smoke from fires, long-term cloud cover, or shortage of high wind speeds.

2. Supply challenges and/or increased demand could lead to a Widespread Outage when operating resources are insufficient during periods of peak demand. The reasons could include generator-scheduled maintenance, forced outages due to weather conditions and loads, and low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. Additionally, variable generation from renewable wind and solar resources often does not provide the same contribution to dependable capacity during peak demand as conventional generation resources. The output from these resources can vary depending on the environment and the local weather conditions. As California's dependence on variable renewable generation increases, there is an increase in the need to be able to draw on unanticipated resources that can be reliably called upon on short notice. There is also a rise in the need to have the option to obtain additional imports from outside of the area in order to balance supply and demand. Moreover, the high levels of solar resources in California cause the daily load shape to change; this can mean that greater amounts of flexible resources are needed to match steep ramping conditions during times when the change in wind or solar output changes rapidly. The electric grid must handle an increasingly variable power supply profile. This poses challenges to safety, grid stability, asset condition, reliability, and resilience.

3. Insufficient situational awareness could lead to a Widespread Outage because system operators are operating in a dynamic environment. Accordingly, the operators must maintain reliability, anticipate events, and respond appropriately when or before events occur. For instance, some transmission line outages are longer than others, and outages of long duration could leave the transmission system at risk for longer periods of time.

4. Human performance could lead to a Widespread Outage when system operators are working with degraded situational awareness that impacts their ability to make informed decisions to help ensure reliability for the given state of the bulk power system. Unexpected outages of systems needed for communications, monitoring and control of equipment, or planned outages without appropriate coordination or oversight, can leave system operators with impaired visibility. Human error is one of the potential causes for incorrect operations to occur.

5. Equipment failure could lead to a Widespread Outage due to the unexpected failure or outage of a system component, such as a generator, transmission line, or other electrical element.

6. Cyber or physical sabotage could lead to a Widespread Outage when large portions of the grid are rendered inoperable or damaged, especially within vulnerable areas of the grid.

D. Potential Outcomes and Consequences

The outcomes of a widespread outage can logically be grouped into buckets with associated variables such as the number and/or type of customers impacted, the quantity of load loss, and the duration of load loss. The consequences associated with any widespread outage outcome could have potential safety, reliability, and financial consequences that increase in severity depending on such factors as restoration time and number of customers impacted. For example, a lasting outage may disrupt communications and transportation, close businesses, cause food spoilage and water contamination, and prevent use of medical devices and central air conditioning or heating. Additionally, federal energy regulators may impose penalties for violations of law and reliability standards.

II.

RISK MITIGATION ACTIVITIES

Table II-1 below outlines some of the risk mitigation efforts SCE undertakes to help reduce the potential for a Widespread Outage event. As noted, there is overlap with risk mitigation efforts discussed in other risk chapters and appendices.

Table II-1
Potential Widespread Outage Drivers and Risk Mitigation Efforts

Potential Widespread Outage Drivers	SCE Risk Mitigation Activities
Climate Change / Natural Disasters / Weather	See Other Risk Chapters*
Supply Challenges and/or Increased Demand	Increased Grid Flexibility
Insufficient Situational Awareness	Situational Awareness Tools
Human Performance	Training
Equipment Failure	Annual Planning Assessments
Cyber or Physical Sabotage	See Other Risk Chapters**

* For additional discussion on drivers that can potentially lead to a Widespread Outage, please see: (a) Chapter 4 - Wildfire and PSPS; (b) Chapter 7 – Seismic; and (c) Appendix B - Climate Change.

** For additional discussion on drivers that can potentially lead to a Widespread Outage, please see: (a) Chapter 7- Cyber Attack; and (b) Chapter 11 - Physical Security.

A. Increased Grid Flexibility

The risk and consequences of supply challenges and/or increased demand are mitigated by incorporating system flexibility into future grid architectures (e.g., controls to rapidly reconfigure or isolate parts of the grid). This includes the use of battery energy storage systems, distributed energy resources, and controllable loads. In fact, SCE will substantially increase the amount of energy storage capacity it has available to mitigate the risk of potential customer outages if the West experiences a summer of extreme heat.

On December 16, 2021, the CPUC authorized SCE to enter into a $1.226 billion, 537.5 megawatt (MW) engineering, procurement, construction, and maintenance energy storage contract with Ameresco, Inc. to increase grid reliability for next summer. This additional SCE-owned storage complements the long-term capacity contracts completed last year — 1,355 MWs of utility-scale battery storage and 5

MWs of demand response that uses energy from customer-owned energy storage. It will bring SCE's total amount of installed and procured storage capacity to about 2,810 MWs.[5]

SCE has developed a whitepaper, titled Reimagining the Grid, that describes its long-term vision of a future grid that must evolve to integrate changes in how electricity is generated, stored and used.[6] Additionally, SCE considers variability in resources and demand to ensure a sufficient level of flexible resources, maintain fuel assurance, and plan and operate the bulk power system with inverter-based resources. Furthermore, SCE is actively engaged within various industry technical committees to develop guidelines and recommendations, as well as promote the reliability of the North American bulk power system. SCE also collaborates and engages with utilities, regional transmission organizations, policy agencies at all levels (i.e., federal, state, and local), communities, customers, and other stakeholders to shape the policy and technology landscape and transform how we plan, design, build, and operate the grid.

B. Situational Awareness Tools

The risk and consequences of insufficient situational awareness are mitigated through the use of various situational awareness tools that include, but are not limited to an Energy Management System (EMS). EMS is used as a primary means to monitor, control, and optimize the performance of the generation and/or transmission system, transmission outage planning, load forecasting, geomagnetic disturbance/weather forecasting, data from neighboring entities' operations, and interpersonal communication within SCE and with neighboring systems.

SCE also uses tools to monitor transmission line and equipment status, voltage, protection systems, generation facilities, and system frequency. SCE will engage integrated, high-fidelity measurement and monitoring of grid state and assets, from generation situational awareness to customer levels, with high spatial and temporal resolution.

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5 https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-approves-energy-storage-contract-for-sce.

6 *See* https://www.edison.com/home/our-perspective/reimagining-the-grid.html.

C. Training

The risk and consequences of human errors are mitigated through an understanding of the reasons mistakes occur, and application of the lessons learned from past events and near-misses. Events analysis, lessons learned, and good industry practices are being applied to further improve the reliability of the bulk power system. Additionally, SCE complies with applicable NERC Reliability Standards related to Personnel Performance, Training, and Qualifications (PER).[7] SCE ensures that operation personnel have both the knowledge and skills to:

- Properly perform company-specific reliability-related tasks; and
- Apply operating policies, procedures, and requirements to normal, emergency, and system restoration activities in order to maintain or exceed applicable operational policies and rules.

Currently, training capabilities include instructor-led training in both classroom and virtual settings, web-based training, self-study, simulation exercises, and on-the-job training. Feedback questionnaires are used to collect data about the training experience, and knowledge assessments are used to determine knowledge retained. Also, when appropriate and applicable, behavioral assessments can be used to confirm training performance on-the-job.

SCE also has continuing education training programs, including but not limited to an allotted off-shift training week once during every six-weeks, an annual multi-day training course that typically is 16 hours in total, and an annual emergency training session typically consisting of 24 total hours.

During coordinated training sessions, SCE runs several simulations (e.g., past events, supply challenges, and seismic events) that include injecting new technologies (e.g., battery energy storage systems) to provide the best "real life" scenarios. During scheduled shifts, a minimum of three NERC-certified operating personnel are always scheduled. These personnel actively monitor and oversee all electric system operations for SCE. Operators in-training only work under the direct supervision of NERC-certified personnel, and SCE increases staffing levels to address any situation or emergency as needed. It is important to note that while training assists SCE personnel in mitigating the risk and

[7] https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx.

consequences of human errors, adverse reliability impacts from neighboring utilities due to human error may cascade throughout the interconnected electric system and into SCE's service territory. As such, SCE has a System Emergency Response Plan designed to curtail interruptible and firm load within SCE's service territory. This Plan also provides a course of action in the event that the CAISO implements CAISO Operating Procedures 4420, System Emergency and/or 4510, Load Management Programs, and Underfrequency Load Shedding.

D. Annual Planning Assessments

The risk and consequences of equipment failure from a planning perspective are mitigated by the following: SCE developing its bulk power system based upon established performance requirements within the planning horizon that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies (i.e., the unexpected failure or outage of a system component, such as a transmission line). SCE annually performs a transmission reliability assessment of SCE's portion of the CAISO-controlled grid to maintain or improve transmission system reliability.

SCE's annual planning assessment seeks to: (1) evaluate the performance of the SCE transmission system under various load conditions as forecast within the one- to ten-year planning horizon; (2) determine transmission constraints under stressed system conditions; and (3) identify infrastructure upgrades needed to improve the reliability of the transmission system and comply with applicable FERC-approved NERC Reliability Standards, Western Electricity Coordinating Council (WECC)-approved Regional Reliability Criterion, CAISO Planning Standards, and SCE Transmission planning criteria. Additionally, the CAISO performs an annual transmission reliability assessment of the CAISO-controlled grid (including SCE's portion) to maintain and enhance transmission system reliability to levels appropriate for the California system.