A Regulatory Review of the Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case

Investigation 18-11-006

Principal Author:
Martin Kurtovich, PE

Contributors:
Wendy Al-Mukdad, PE
Junaid Rahman
Jeremy Battis

May 24, 2019

Table of Contents

PREFACE

At the recent California Wildfire Technology Innovation Summit, noted author and academic Edward Struzik[1] opened the event with his compelling stories of wildfire in Canada and his insights from interviews with noted scientists, government officials and the public. He warned of the necessity for change in Canada and California, that "business as usual" cannot continue and that decisions and policies that we make now as a global community will have a profound influence on what our world looks like for our children and their children.

A good example of this necessary revamping is recent changes to California utility law and the Public Utilities Code. In 2014, the California Public Utilities Commission (CPUC) initiated the development of a new procedure to assess proposed utility safety investments prior to a general rate case proceeding. In 2018, California utility laws, regulations, and policies were significantly retooled to address growing public safety risks due to aging infrastructure and a changing climate. With the passage of Senate Bill 901, the Governor's Executive Order on Wildfire Safety, and the CPUC's adoption of new policies and procedures to support its risk-informed decision-making, a new utility safety framework has been established in California. This new framework directly impacted the review of Southern California Edison (SCE) Risk Assessment and Mitigation Phase (RAMP) Report (Report). This document is intended for major California investor-owned utilities (IOUs) to demonstrate their commitment to public safety and the citizens of California by describing

1) the significant public safety risks associated with their operations and infrastructure,
2) the utility's commitment to public safety through sound management and investment
3) proposed mitigation plans and alternatives to assess how mitigations impact safety risk

With new specificity and objectives mandated by State law, California's utility safety efforts must meet the specific objective prescribed by State statutes – to minimize the risk of catastrophic events posed by their equipment and operations. This new framework demands the highest level of safety, reliability and resiliency of all utility assets, particularly transmission and distribution equipment and operations.

This framework includes the following -

- Utility programs that address short and long-term safety objectives
- Safety Performance Metrics
- Methodology for identifying enterprise wide safety risk and wildfire-related risk
- Description of safety mitigation strategies and programs which include climate adaptation

[1] Struzik, Edward, Firestorm: How Wildfire Will Shape Our Future, Island Press, 2017

These are a few of the new requirements that California electric utilities must address as they move forward in planning and development of their utility safety programs.

The purpose of the RAMP review (Review) by the Commission's Safety and Enforcement Division (SED) is to ultimately assess whether the utility has described and justified proposed safety mitigations. With the new framework, this Review for the first time can start to ask the hard questions of how utilities demonstrate safety leadership and commitment. This Review first examines SCE's safety challenges, performance, and infrastructure. It then summarizes how SCE identified its utility risks. This Review provides an assessment of those risks and ranks them to emulate safety management practices common in other heavy industries. This ranking aids in the comparison and evaluation of utility mitigation programs and safety management. Finally, individual mitigation plans for each of SCE's risks is summarized and critiqued, with individual staff analysis available in appendices. The Review concludes with conclusions and recommendations for SCE's upcoming general rate case (GRC).

This Review also introduces new concepts previously not considered by the Commission but is an integral part of the State of California's climate adaptation efforts. This includes research on wildfire risk by Federal agencies in California over several decades and the use of utility data analytics to assess a proposed mitigation plan. This assessment serves as a demonstration of the potential of RAMP reviews for identifying where utility proposals are not supported by utility safety history and operational experience.

The intent of this Review is to contribute to the Commission's upcoming SCE GRC proceeding, inform other related utility safety proceedings (i.e. Grid Safety & Resiliency Program, Wildfire Mitigation Plan, etc.), climate adaptation proceedings, and contribute to CPUC efforts to develop a mature and robust risk-informed decision making oversight process for keeping California utilities safe.

EXECUTIVE SUMMARY

Recent catastrophic wildfires in California have created a new reality for large investor-owned utilities (IOUs) in California. With this, the California electric industry and the State of California must address the increasing risks that come from operating the largest electric system in the US in a State that is on the front lines of developing mitigation strategies for a changing climate.

The recent report by Governor Newsom's Strike Force, Wildfires and Climate Change: California's Energy Future, recommended strengthening utility regulation and enforcing safety standards that reflect the new safety realities for utilities. This recommendation is the result of the last five years of deliberations between the Commission, utilities, stakeholders, the legislature and Executive Branch on developing a new sustainable utility safety framework for California in the 21st century.

Since the adoption of a Safety Policy (see Appendix B) for utilities in 2014, the Commission, working with the California electric industry and stakeholders, has developed this framework which includes adding a new risk-informed decision-making process as part of a utility's general rate case (GRC) proceeding. California's large IOUs now provide a report on their assessment of public safety risks associated with their operations and infrastructure every three years. Included in the report are preliminary mitigation proposals that attempt to identify the safety benefits of each mitigation to enable greater accountability and transparency in a utility's investment requests. This Risk Assessment and Mitigation Phase (RAMP) report is reviewed by the CPUC Safety and Enforcement Division (SED). SED produces an assessment or review (Review) of the utility RAMP report. In its review, SED examines how well the utility explains public safety risks in its service territory. Next, SED assesses whether there is satisfactory justification for the proposed mitigations based on the utility's estimated reduction in safety risk.

This review process has been in place since 2016 with both SEMPRA Utilities and Pacific Gas and Electric Company (PG&E) having previously submitted their RAMP reports with subsequent SED Reviews. This is the first RAMP report submitted by Southern California Edison (SCE) and is intended to address the utility's safety mitigation efforts within its service territory through 2023.

A NEW UTILITY SAFETY FRAMEWORK FOR CALIFORNIA

With the recent passage of Senate Bill (SB) 901, Governor Newsom's Executive Order on Wildfire Safety (N-05-019) and recent Commission Decisions related to utility safety, an evaluation of SCE's report was done within the context of a new era in utility safety and a new relationship between the IOUs and the citizens of California.

The signing of SB 901 in September 2018 serves as an agreement between the utilities and California. The Executive Order directed State agency attention and actions toward vulnerable communities, those communities with the highest public safety risk in the State. The Strike Force recommendations include reviewing high-risk industry regulatory models and exploring options for incorporating the latest climate work, such as the State's recently published 4th Climate Assessment.

Adding to this evolving regulatory setting was the fact that the SCE RAMP Report is the first to utilize a fully developed risk modeling protocol that was under development for the past five years through the Commission's Safety Model Assessment Proceeding (SMAP). With the first use of a Multi-Attribute Risk Score (MARS) that enables the comparison of risks across a utility's operations, a more comprehensive conversation is possible about risks, mitigations, and tradeoffs as part of a utility's general rate case proceeding. SED chose to do a full evaluation that meets the original intent of the Commission Decision adopting the RAMP process. That intent is to determine if a utility has fully identified the public safety risks within its service territory and then developed a mitigation program that is sufficiently supported by data and risk analytics.

Unlike the RAMP reports submitted by PG&E and SEMPRA, SCE's RAMP report was also complemented by two coincidental SCE submissions to the CPUC, their Wildfire Mitigation Plan (WMP) for 2019, and a March 2019 RAMP Report addendum that SCE voluntarily submitted to the Commission.

EVALUATION OF SCE RISK ASSESSMENT AND SAFETY MITIGATION PROPOSALS

The SCE Report identifies nine primary risks to public safety, including wildfire, cyberattack, and contact with energized equipment. The SED Review follows through on one Strike Force recommendation by utilizing a common tool in high-risk industries to prioritize the risks identified by SCE. By ranking SCE risks in terms of safety priorities, the CPUC can better evaluate where additional utility investment is needed. Using a format common in the chemical process industry, SED ranked wildfire safety and flooding/mudslides as Tier 1 risks that have the potential of catastrophic or cascading failure impacts on public safety. Tier 2 risks which are classified as standard operation risks that electric utilities must address on a day-to-day basis. Tier 2 risks defined by SED consists of 1) contact by energized equipment, 2) cyberattacks, 3) physical security, 4) underground equipment failure, 5) occupational (employee, contractor) safety and 6) seismic risks to generation, distribution and transmission assets. Tier 3 risks were defined as utility risks regulated by the Federal government, specifically hydro asset safety and nuclear decommissioning, storage and transportation.

In terms of the proposed mitigation plans that SCE put forth in its Report, the SED evaluation exposed shortcomings and lack of supporting information to justify the proposed utility expenditures.
For example, for the risk of contact with energized equipment, SED evaluation of this risk through an examination of reported injuries and fatalities associated with SCE operations from 2014 through 2018 indicate that this safety risk is in decline and SCE has shown improvement in

safety performance for this risk. This evaluation also identified the key risk drivers and confirmed that events such as downed wires and mylar balloons have a limited impact on this risk. Yet SCE is proposing a mitigation effort costing over $1/2 billion and its primary mitigation, covered distribution lines, does not address some of the major drivers for this risk.

For wildfire safety, unlike Sempra and PG&E in their prior RAMP filings SCE had three opportunities to propose mitigations with supporting documentation, 1) the RAMP report, 2) the Wildfire Mitigation Plan and the 3) SCE's RAMP addendum that it submitted in March 2019. For Wildfire Safety in particular, SCE submitted two different conflicting proposals in the WMP and RAMP filings. Additionally, the RAMP Report and addendum only address wildfire safety associated distribution assets and did not address wildfire risks associated with SCE transmission assets. This resulted in confusion and limited understanding of what SCE's actual wildfire mitigations proposals are for 2019, which the WMP covered, or for the years 2018 – 2023, which is the period of interest for the RAMP Report and upcoming general rate case. Also, all three documents omitted proposed expenditures for wildfire response and recovery. SB 901 amended Public Utilities Code Section 8386 with a requirement that utilities include a description of how it plans to prepare for and restore service after a wildfire. Yet in its WMP and both RAMP documents, SCE proposed no activities or funding for response and recovery efforts, unlike what the other two California IOUs proposed in their recent Wildfire Mitigation Plans.

With recent changes to California utility laws and regulations, electric utilities in the future will need to produce RAMP reports and Wildfire Mitigation Plans that identify all mandated program components and support risk-informed decision-making for proposed safety mitigation plans in upcoming general rate case filings.

Conclusions

While the SCE RAMP Report did break new ground in terms of risk modeling and assessment, it failed to fully identify all public safety risks within its jurisdiction[2]. Inconsistency and in some cases, contradictions in SCE's RAMP Report with other documents indicate that SCE management needs to better coordinate planning and executing utility safety programs to protect the public. For its upcoming general rate case filing, this Review makes recommendations for how SCE should address this Report's shortfalls to allow the Commission to make a fully informed and vetted decision on the SCE funding requests. In closing, this Review exhibits the importance of in-depth regulatory review of utility safety programs, furthers the Commission's efforts in crafting transparent and accountable risk-informed

[2] In I. 16-08-018, Commission Order instituting investigation in to the risk assessment and mitigation phase submission of Southern California Edison Company was opened in accordance with the procedures adopted in D.14-12-025 and D.16-08-018. Those two Decisions requires the utility to prioritize risk mitigation and specifies a protocol that utilities must follow in identifying and prioritizing risks. This includes the utility starting with all risks listed in its enterprise risk register. The Safety Model Assessment Proceeding Final Decision D.18-12-014 established this protocol as Commission policy that all utilities are required to follow in their RAMP filing.

decisions and actions, and supports California's new utility safety framework. It is hoped that it results in stronger and sustainable utility safety program that results that minimizes public safety risks and maximizes resilience and reliability.

1 UTILITY SAFETY IN A NEW ERA

In the aftermath of one of the worst natural gas pipeline explosions in US history in San Bruno, California, in 2010, the California Public Utilities Commission (CPUC or Commission) adopted a Safety Policy Statement (see Appendix B) to strengthen its commitment to and oversight of utility safety in California. As a demonstration of its new commitment, the Commission instituted a triennial proceeding for evaluating safety mitigation budget proposals anticipated for a utility's upcoming General Rate Case (GRC) proceeding. Known as the Risk Assessment Mitigation Phase (RAMP) proceedings, all major California investor-owned electric utilities (IOUs), Pacific Gas & Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), Southern California Gas (SoCalGas), and Southern California Edison (SCE), are required to participate in these proceedings. The intent is to enable more transparency and accountability into utility safety investments with thorough screening by the Commission. By introducing a risk-informed decision-making process to the GRC, the Commission's intent is to ensure that IOUs are making the proper investments in the appropriate mitigations at the locations in their system with the most significant safety risks.

Since the adoption of this requirement by the Commission, SDG&E/SoCalGas (Sempra) and PG&E have submitted RAMP reports before their GRC proceedings. Commission staff has reviewed both reports, held workshops, and submitted their comments to the appropriate GRC proceeding. The RAMP report submitted by SCE in November 2018 was its first and this Review is the Safety and Enforcement Division's (SED) examination of SCE's safety management and programs. (In January 2017, SED did prepare a report on Risk & Safety Aspects of SCE's GRC Application for 2018-2020 but it was not based on a RAMP filing.)

In light of events of 2017 and 2018 involving utility assets and public safety, the legal and regulatory landscape has recently shifted. With the passage of Senate Bill 901 (SB 901), this defining legislation established a new framework for utility safety in California. By establishing how California electric utilities define, plan for and actively manage safety risk, this framework defines the new era. As such, SED believed it was essential that this framework be incorporated into the Commission's review of the Southern California Edison (SCE) RAMP Report. While SCE submitted its report in November 2018, due to the impact of SB 901 and the recently submitted SCE Wildfire Mitigation Plan, (WMP) SCE subsequently submitted a RAMP amendment in March 2019.

This framework expands the safety planning and management of utilities by requiring safety mitigation strategies and programs to "minimize the risk of catastrophic wildfire" with "the highest level of safety, reliability, and resiliency." It requires a continuous effort to identify key risks, define strategies and programs to mitigate these risks and incorporate a management system that will include establishing performance metrics, continuous evaluation of effectiveness, and independent evaluation of implementation. While the initial RAMP proceeding sought to ensure greater utility responsibility and action to address safety risks through planning, the SB 901 provides a more holistic management framework that holds utilities accountable for meeting not only safety goals and objectives but to also address aging infrastructure and changing climate.

Adding to this framework is the Governor's January 2019 Executive Order (EO) N-05-19, directing all State agencies, including the Commission, to take immediate actions to prevent destructive wildfires. The Governor emphasized pursuing a strategic approach where necessary actions are focused on California's most vulnerable communities as a prescriptive and deliberative endeavor to realize the greatest returns on reducing risk to life and property.[3]

Given recent changes to California law and policies regarding utility safety and resilience, this review's primary objective is to support the Commission's role in the upcoming SCE General Rate Case (GRC) proceeding and other relevant safety proceedings, scheduled to begin in September 2019. This review includes comments on specific mitigation plans intended to address utility safety risks, it also makes recommendations on material that the utility should include in its GRC filing. This additional information will allow for Safety and Enforcement Division and other stakeholders to more fully scrutinize utility safety mitigation proposals and allow for better decision-making in that proceeding.

[3] CalFire, Community Wildfire Prevention and Mitigation Report, February 2019

2 Review of SCE's 2018 RAMP Report

The Commission instructs the Safety and Enforcement Division (SED) in Decision D. 16-08-018 of the S-MAP, to adopt the Cycla 10-step framework as a common yardstick for evaluating the utility's mitigation programs for three characteristics –

- maturity,
- robustness, and
- thoroughness[4]

The Cycla 10-step framework (see Figure 1 below) was originally developed by the Cycla Corporation[5] to evaluate PG&E's Test Year 2014 general rate case application, with a specific focus on safety and resilience. The purpose of the Cycla evaluation was to determine how PG&E's decision processes explicitly incorporated safety risk and resilience.

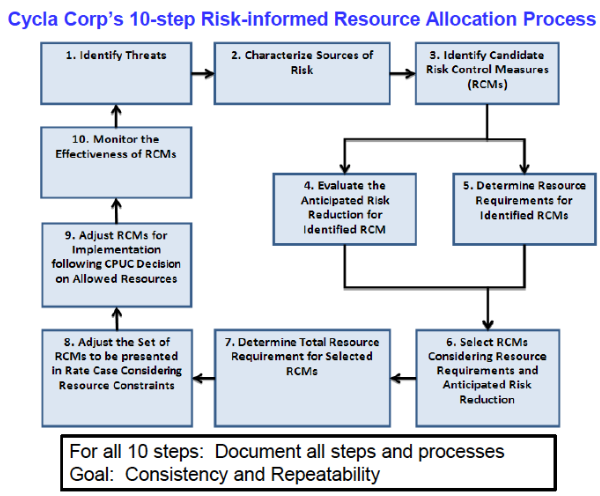


Figure 1: Cycla 10-Step Process

More recently, SB 901 specifies new review processes for the Commission, specifically for electric IOU annual Wildfire Mitigation Plans (WMPs). SB 901 established a close association between utilities WMPs and their associated RAMP reports to justify proposed mitigation plans and budgets[6]. This includes a requirement that the Commission and CalFIRE enter into a

[4] D.16-08-018, Order Paragraph 4

[5] The Cycla Corporation was engaged by the Safety and Enforcement Division as a consultant to evaluate the gas distribution portion of PG&E's Test Year 2014 general rate case.

[6] SB 901, amend Sections 399.20.3, 854, 959, 1731, 2107, 8386, and 8387 of, to add Sections 451.1, 451.2, 748.1, 764, 854.2, 8386.1, 8386.2, 8386.5, and 8388 to, to add Article 5.8 (commencing with Section 850) to Chapter 4 of Part 1 of Division 1 of, and to repeal and add Section 706 of, the Public Utilities Code, relating to wildfires

Memorandum of Understanding (MOU) to cooperatively develop consistent approaches and share data related to fire prevention, safety, vegetation management, and distribution systems and to share results from various fire prevention activities.

This law also amends Section 8386 of the Public Utilities Code to require that IOUs submit WMPs that include

- Description of preventive strategies and programs to minimize the risk of electrical assets causing catastrophic wildfires, including consideration of dynamic climate change risks
- Description of metrics for evaluation of IOU performance

SB 901 also calls for identification and prioritization of all wildfire risks throughout the IOU's service territory including all relevant risks and risk mitigation information that is part of the Safety Model Assessment Proceeding and Risk Assessment Mitigation Phase filings. This includes -

1. Risk associated with design, construction, operations, and maintenance of assets
2. Particular risk associated with topographic and climatological factors throughout the different areas of the IOU's service territory
3. How the WMP accounts for the wildfire risk identified in the IOU's RAMP filing
4. Description of the actions the IOU will take to ensure its system has the highest level of safety, reliability, and resiliency
5. Ensure that IOU system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment and facilities, such as undergrounding, insulation of distribution wires and pole replacement
6. Identification of any geographic area in the IOU's service territory that is a higher wildfire threat than is currently identified in a commission fire threat map and where the Commission should consider expanding the high fire threat district based on new information or changes in the environment
7. Establish a methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with other IOUs.
8. Plans to prepare for and restore service after a wildfire
9. Performance metrics used by the utility and Commission to track the implementation of utility resilience programs and mitigation plans.

Both the Cycla Framework and SB 901 require similar efforts. For example, Step 1 of the Cycla Framework requires consideration of all credible and foreseeable threats, industry experience, and compounding effects from interacting threats. Both specify that this step should have sufficient granularity of threats and assets[7], with SB 901 including identification of areas with

[7] Haine PE, Steven, "Cycla's 10-Steps for Risk-Informed Resource Allocation for Rate Cases," California Public Utilities Commission, August 3, 2015

higher wildfire threat and consideration of topographic and climatological factors. The Cycla Framework then requires the IOU to characterize sources of risk as a function of frequency and consequence. This includes considering such factors as - 1) asset conditions, 2) recent utility experience, 3) effects from interacting threats and 4) potential scenarios, such as those based on recent Climate Change Assessments[8].

California's new framework as defined by SB 901 instructs IOUs to develop mitigations that can ensure its system has the highest level of safety, reliability, and resiliency. This should be based on industry best practices, current operator practices, and requires consideration of new technologies, safety investigations, and advisories. The IOU must evaluate the anticipated effectiveness of each mitigation on safety and resilience both individual and collectively as a portfolio of mitigation measures. Estimated costs are then compared to anticipated improvements in safety and resilience to determine the IOU's preferred mitigation plan. Finally, both the framework and law require monitoring of implementation to determine the effectiveness and impact of overall risks.

Concurrently, Executive Order (EO) N-05-19 signed earlier this year by Governor Newsom directs state agencies to consider risk management through an added socioeconomic lens. It stipulates that state agencies identify geographic areas with populations that are particularly at risk during natural disasters. This new policy was initiated so that when paired with traditional natural risk factors, a more accurate assessment of the real human risk can guide preventative action to help prevent loss of life, particularly for vulnerable communities and segments of California’s population. As a result of this Executive Order, CalFire has produced a Community Wildfire Prevention and Mitigation Report that identifies approximately 200 vulnerable communities within the State. While SB 901 and the Executive Order were after SCE's preparation of their RAMP report which was submitted to the Commission in November 2018, this review does take into account these new State policies to identify how utility safety and resilience programs can be compliant within the State’s new framework policies.

Compliance will require ensuring that IOUs more closely monitor its system and report its conditions. Operationally, utility performance must be assessed in terms of effectiveness in addressing safety risks. With new technologies and tools, the California electric utility industry should be at the forefront of utilizing these new capabilities to improve understanding of asset risks, managing costs, and minimize risk. This is particularly prudent in light of San Diego Gas and Electric Company's demonstrated leadership in utility wildfire safety. That utility's current proposals include significant new investments in new grid controls, sensors, and software to allow for better prevention and responses to major events that impact the grid.

[8] For example, Moser PhD, Susanne C et al, “The Adaption Blindspot: The Connected and Cascading Impacts of Climate Change on the Electrical Grid and Lifelines in Los Angeles,” California Energy Commission, August 2018

In reviewing SCE's RAMP Report and future GRC filing, it is important that the Commission is cognizant of evolving regulation related to climate adaptation. In a 2016 Commission Report on climate adaptation[9], the Commission recommended that California IOUs conduct rigorous vulnerability assessments as per the 2016 guidance from the US Department of Energy Partnership for Energy Sector Climate Resilience[10]. Started in 2015, this national partnership includes California electric IOUs and public electric entities including SCE. This partnership was established with the recognition that an effective resilience strategy for the US energy system will require accelerated investment in climate-resilient energy technologies, practices and policies.

While the current SCE RAMP reports addressed climate change, specifics regarding how the Commission would like IOUs to address climate resilience is still under development. Most notably, the Commission has a current proceeding, R. 18-04-019, Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation to codify Commission climate adaptation policies regulate utility resilience efforts. This includes

- Identify key climate risks
- Develop an inventory of assets and potential effects
- Identify and prioritize vulnerabilities
- Assess the magnitude and probability of impacts

The 2016 report also recommended that IOUs take the results of the above tasks to complete expanded vulnerability assessments, addressing specific issues discussed in the report such as

1) assessing the IOU's systems as a sum of its assets,
2) assessing future system assets and operating conditions, and
3) assessing the vulnerability of customers.

From this, it is recommended that IOUs developed Resilience Plans that address long-term (5-25 years) infrastructure and operational issues that can support future S-MAP and RAMP proceedings.

As noted in the State's 4th Climate Change Assessment, studies found that "flexible adaptation pathways" that allow for the implementation of adaptation actions over time allow utilities to protect services to customers most effectively. While these concepts are not within the scope of this review, the tools used to evaluate SCE's mitigation plan should in the future inform the Commission on how climate adaptation can be integrated with utility safety.

---

[9] Raiff-Douglas, Kristin, "Climate adaptation in the Electric Sector: Vulnerability Assessments & Resiliency Plans," California Public Utilities Commission, January 2016

[10] U.S. Department of Energy, Climate Change and the Electric Sector: Guide for Climate Change Resilience Planning, September 2016

3 SCE Safety Management

a. SCE's Safety Challenges

California's new utility safety framework is a necessity in an era where changing climate conditions and aging infrastructure can exacerbate safety impacts and demands new standards for safety leadership and management.

An example of how the ongoing aging of SCE's infrastructure can impact utility safety planning and proposed investments is SCE's Cable-in-Conduit (CIC) underground assets.

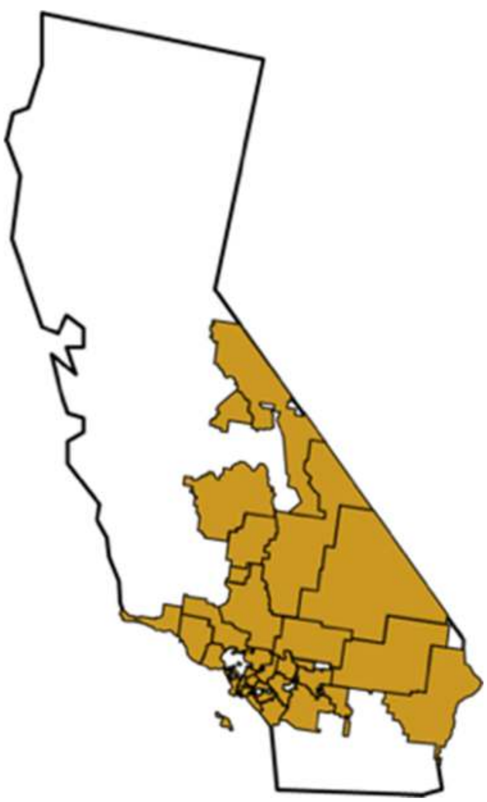


Figure 2: SCE service territory and districts

With a service territory of 50,000 square miles that serves over 400 cities and communities with a population of 13 million, SCE is one of the largest electric utilities in the country. Its' distribution assets include over 1,440,000 wooden poles, over 100,000 circuit miles of overhead primary conductor and 50,000 circuit miles of underground primary conductor, comprising 4600 distribution circuits.

Using reliability metrics to evaluate the condition of a utility's assets, 2014 SAIDI data shows that equipment failure is responsible for almost 50% of outage impacts as measured in outage duration. The System Average Interruption Duration Index (SAIDI) indicates the total duration of interruptions for the average customer across the electric system during a year. It is commonly measured in minutes or hours of interruption. Mathematically it is the total number of customer-minutes of interruption divided by the total number of customers on the system. With equipment failure as the dominant cause, this reliability metric informs the Commission on how SCE's equipment is performing and its impact on safety risk.

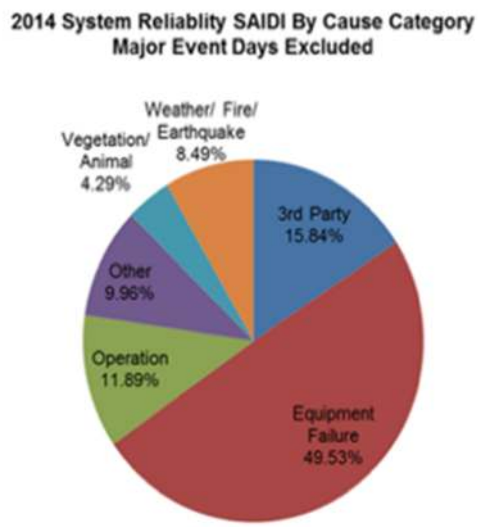


Figure 3: SCE 2014 System Reliability SAIDI By Cause Category Major Event Days Excluded

This is a common phenomenon with aging infrastructure. As infrastructure ages, performance declines, failures increase, and utilities must focus operations on responding to those failures. SCE data on its underground system shows that these electric assets average over 20 years in age and the utility's data also show that equipment failure accelerates after 20 years.

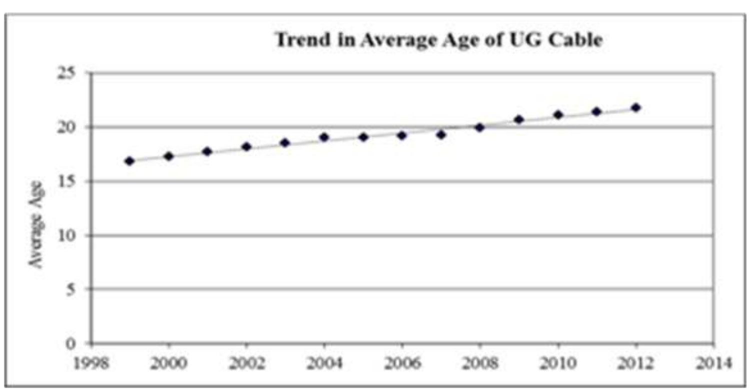


Figure 4: SCE Underground Cable – Average Age through 2013

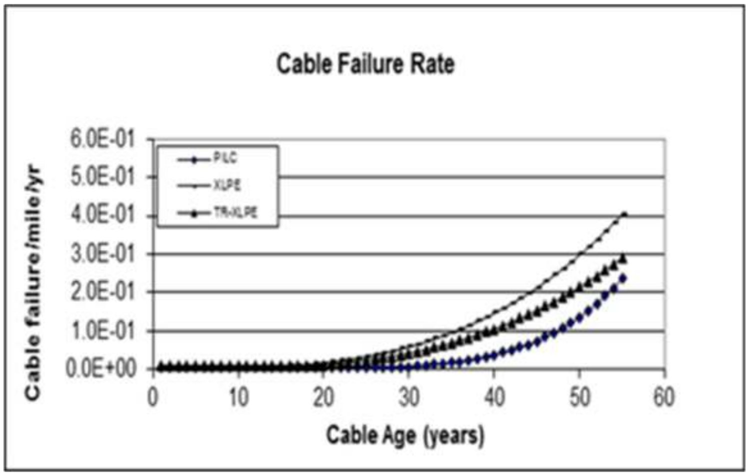


Figure 5: SCE Underground Cable - Failure Rate versus Age

With 13,000 miles in polypropylene tubing, known as Cable In Conductor (CIC), this is a risk to system reliability which indirectly impacts public safety. SCE has projected that over the next 30 years, failure of CIC circuits will increase six-fold.

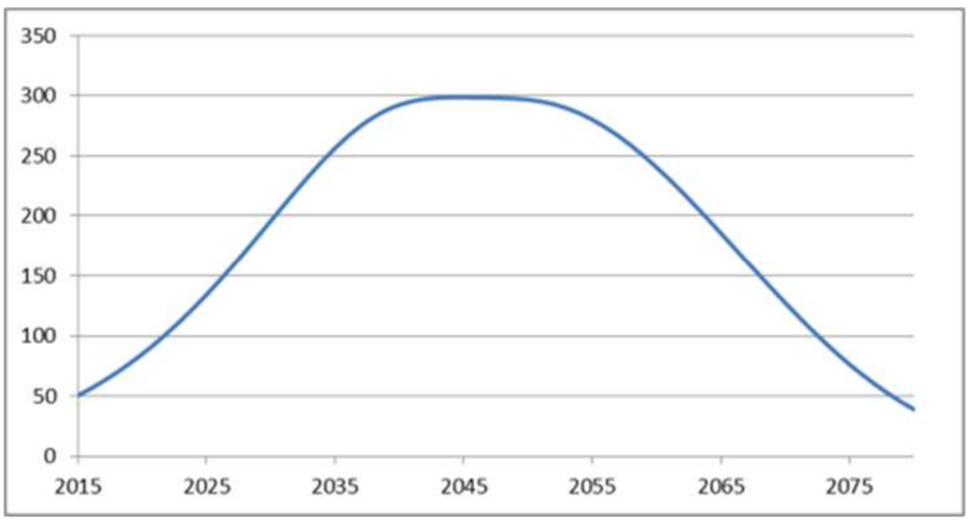


Figure 6: Miles of SCE CIC Conductor Expected to Failure Volume

This type of conductor has a mean-time-to-failure (MTTF) at 41 years for % of CIC population is older than MTTF.

b. SCE's Safety Performance

Last August during the open comments portion of a meeting of the San Onofre Nuclear Generating Station (SONGS) Community Engagement Panel meeting in Oceanside, an employee of an SCE subcontractor that is responsible for industrial safety at the SONGS decommissioning project informed the Panel that a litany of safety shortcomings had occurred at the job site. This included an incident the week before in which one of the canisters holding spent nuclear fuel that was being lowered into a dry cask storage vault could have fallen 18 feet[11]. It was also relayed how similar problems have occurred before, that onsite workers are not informed of safety issues, and SONGS does not have "proper personnel to get things done safely[12]" There is currently 3.55 million pounds of spent fuel sitting on the site, next to Interstate 5 and a population of 8.4 million within 50 miles of its location.

Two weeks later, the Nuclear Regulatory Commission (NRC), the Federal agency that regulates SONGS operations announce a "special inspection" surrounding the management of spent fuel at SONGS. A team of three inspectors spent a week at the facility and in mid-October released its preliminary findings. The NRC's preliminary findings from their investigation released last October found that this "near-miss" event resulted from "multiple procedural inadequacies." Specifically, the NRC noted that "Southern California Edison's deficiencies involving training, equipment, procedures, oversight, and corrective actions."

The NRC also found that Holtec's Safety Analysis Report omitted such accidents, resulting in the spent fuel canister being placed in a situation whose impact has never been assessed for public safety and environmental risks. NRC also identified multiple procedural inadequacies. The NRC cited that the utility had not reported this incident within the 24-hour timeframe as required by law and failed to report a similar incident earlier in the year. Finally, the NRC noted that SONGS personnel involved in important-to-safety tasks were not trained and certified or under direct supervision. As a result, SCE cannot transfer spent nuclear fuel to dry storage until they have completed all corrective actions to the satisfaction of the NRC. This includes a new camera system and alarms, contractor training, and additional oversight managers.

Per Nuclear Regulatory Commission public records,

> San Onofre informed NRC Region IV staff of the incident on Monday, August 6, 2018, when the licensee provided a courtesy notification and described it as a near-miss or near-hit event. San Onofre personnel did not report the event as required by regulations. Following prompting by NRC staff, San Onofre submitted an event report (required by 10 CFR 72.75(d)(1)) on September 14, 2018.

---

[11] Nikolewshi, Rob, "Incident with waste canister at San Onofre nuclear plant prompts additional training measures, **San Diego Union-Tribune**, August 10, 2018

[12] Ibid

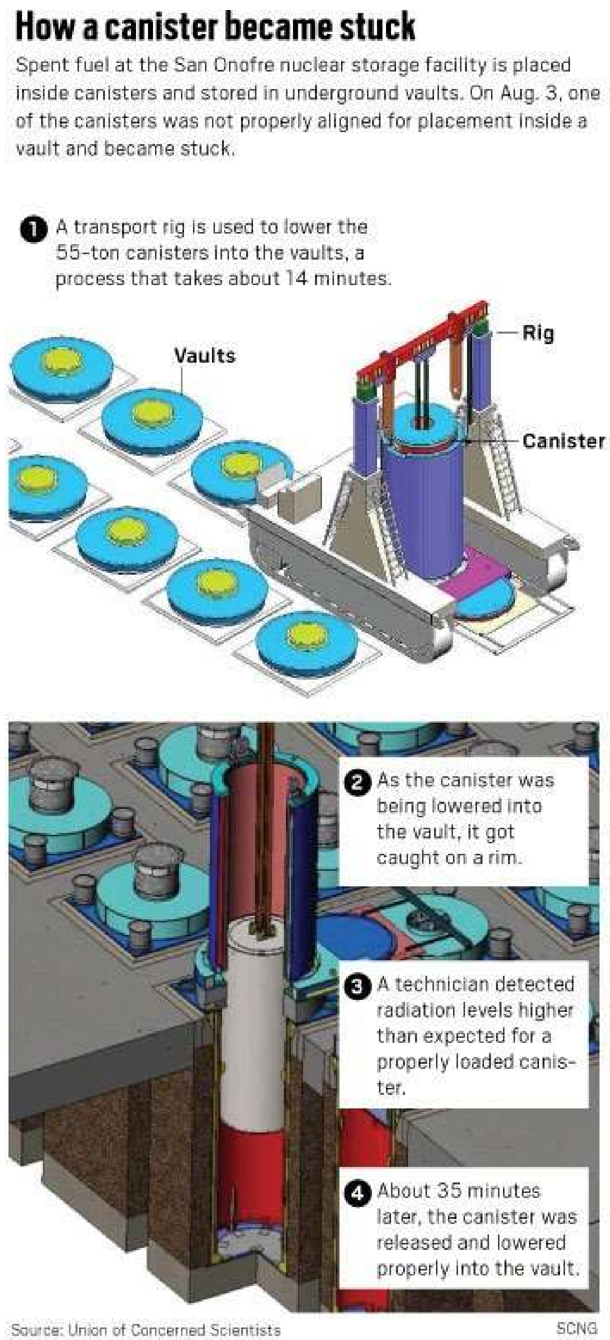


Figure 7: SONGS 2018 Nuclear Safety Violation

After the NRC investigation and report, SCE acknowledged management shortcomings. “The big lesson is, we need to be more intrusive over all our contractors and we will be more intrusive. This is nuclear and industrial safety. We lost sight of that a little bit in this process. We didn't demand that rigor out of our contractors[13]," was SCE's response.

A utility's record in safety and resilience is also reflected in its ability to comply with utility laws and regulations. For example, the issuance of fines against an IOU for incidents that have impacts on public safety, utility liabilities, and financial costs does provide insight into a utility's safety commitment and management. Table One below lists penalties assessed against electric and telecommunication utilities in California over the past ten years. This data was updated in February of this year, it does not take into consideration major wildfire incidents in 2017 and 2018 which may increase that percentage even higher.

Table One: Electric & Telecommunication Penalties Assessed by CPUC in the Last 10 years

Electric & Telecommunication Penalties Assessed by SED in Last 10 Years

February 2019

Entity	Penalties (M = Million)	Total (M = Million)
SDG&E	• $14.75 M combined for the Witch, Rice and Guejito fires.	$14.75 M
SCE	• $37 M for the Malibu Fire ($20 M to General fund) • $16.5 M for the 2011 San Bernardino incident ($10 million general fund) • $8 M for 2011 Windstorm ($5 million general fund) • $2.01 M for the 2013 Huntington Beach incident • $15 M for the Long Beach incident ($4 million general fund) • $50,000 for the 2016 Whittier incident/fatality • $8 M for the Twentynine Palms incident	$86.56 M
PG&E	• $5,569, 313 Kern Power Plant fatality ($2.3 million general fund) • $450,000 citation for 2014 San Jose incident • $50,000 citation for Metcalf 2014 incident • $300,000 citation for violating reporting requirement- Butte fire • $8,000,000 citation for Butte Fire • $400,000 citation for the 2015 Moss Landing incident	$14.8 M
Cox Comm.	• $2 M for the 2007 Guejito fire	$2.0 M
AT&T	• $4 M for the 2007 Malibu fire ($2.3 M to General fund)	$4 M
Sprint	• $4 M for the 2007 Malibu fire ($2.3 M to General fund)	$4 M
Verizon	• $4 M for the 2007 Malibu fire ($2.3 M to General fund)	$4 M
NextG (Crown Castle)	• $14.5 M for the 2007 Malibu fire (8.5 M to General fund)	$14.5 M
	TOTAL	$144.61 M

Based on recent history, the Commission should be cognizant of this utility's compliance performance and how it reflects on a utility's commitment, management, and proposed safety programs.

[13] Sforza, Teri, "Edison Makes Changes at San Onofre, Ready To Resume Loading Nuclear Waste**," Orange County Register**, March 18, 2019

SCE's parent company, Edison International, owns a gas utility on Catalina Island utility known as the Catalina Island Gas Company. This is a separately regulated utility and is not included in this RAMP or related GRC proceedings.

c. SCE's Safety Management

With SCE ownership of a significant proportion of fines assessed over the last 10 years, this occurrence was during a period where Edison was stating that it was making a concerted effort to improve its safety performance. In an October 2009 presentation at the Edison Electric Institute (EEI) Fall Occupational Safety & Health Committee Conference, SCE outlined what it described as its "Safety Culture Journey" (see figure 8 below). A specific goal was to improve the safety culture at SCE and show progress in terms of utility performance. As is shown in the figure, SCE went through a significant effort including employee involvement, a "Safety Culture Report" concluding with the implementation of 2008 safety culture initiatives.

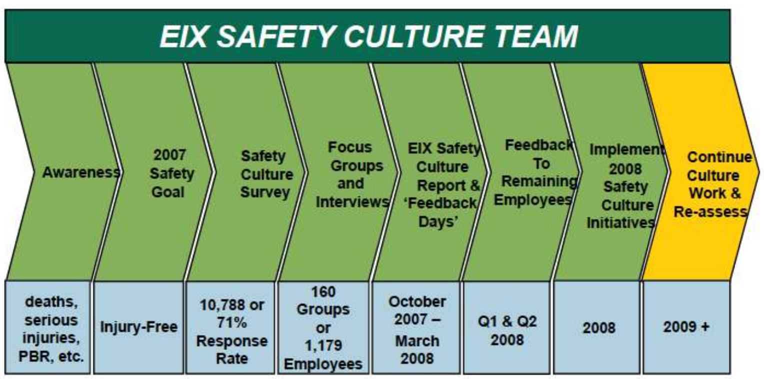


Figure 8: SCE Safety Culture Journey 2009

In the SCE RAMP Report, there are similarities with the 2009 presentation in terms of proposed activities by the utility to further promote a safety culture within the utility. Yet the 2018 RAMP report does not refer to SCE's safety initiatives before 2015. The Report does not describe what impact prior safety culture initiatives have had on safety performance. SCE notes improvements in occupational safety but does not attribute it to any specific utility safety program. It raises questions regarding what the utility is proposing to do differently to address recent safety failures.

d. Comparison of SCE's Safety Performance To Industry

In its December 2018 RAMP Workshop in San Francisco, SCE summarized its perspective on its 2018 RAMP Report. Similar to its presentation in 2009, SCE described RAMP as a "journey", its first RAMP report represents another step in an evolving risk management program. In its report, SCE asserts that it has made "dramatic" improvement in its occupational safety metrics over the past decade.

Ideally, an assertion of dramatic improvement in utility safety over the past ten years is supported with meaningful data that supports and demonstrates why performance has improved at such a rapid rate. Credible justification of such a statement would lend to the utility's credibility and expertise.

Since 2011, SCE has achieved a 64% improvement in employee safety performance and should be commended. In contrast to its 2009 presentation, in its 2018 report, SCE uses a different occupational safety parameter, the Days Away, Restricted, or Transferred (DART) rate, which is presented in the Report as SCE's key safety metric. To determine this rate each year, SCE explains that it uses a combination of historical DART rate performance and expected performance based on top quartile industry benchmarks but does not provide more specifics. SCE does reveal that it also tracks the following safety metrics -

1) implementation of Hazard Awareness and Risk Mitigation Safety Roadmap workstream,
2) performing and communicating effective cause evaluations on all fatalities, serious injuries, and potentially life-altering incidents,
3) worker fatalities,
4) serious injuries to the public, and
5) data breaches or system failures that adversely impact critical infrastructure or result in a breach of data.

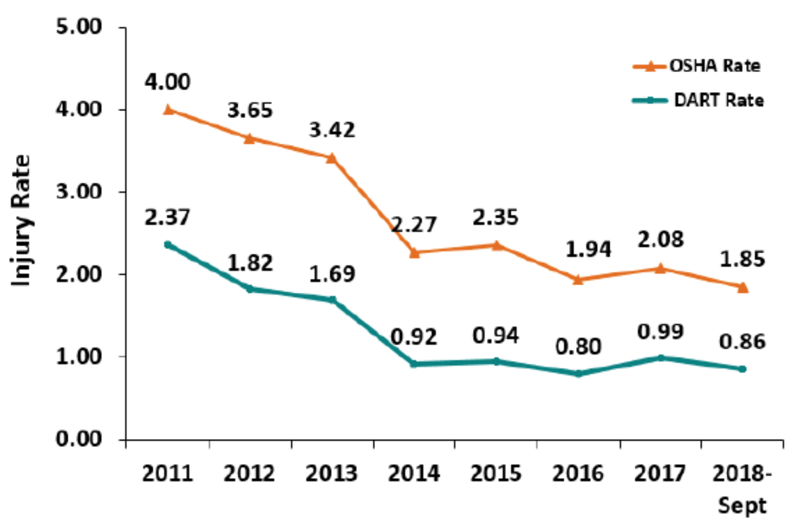


Figure 9: SCE Occupational Safety Metrics: OSHA Rate, DART Rate for period 2011-2018

While SCE tracks these five other performance metrics, the Report itself does not discuss SCE's performance with relation to these other metrics and does not provide any specific information to validate that SCE has tracked this information. With changes to State utility safety policies, IOUs need to track their safety and resilience performance to a certain standard of precision and granularity and report it to the Commission.

The US Bureau of Labor Statistics tracks and reports safety performance in heavy industry since 2003. Figure 10 shows that national safety data for occupational safety is consistent with SCE in that DART scores have been in decline. Parsing 2017 data by industry, the utility industry has a better record regarding occupational safety relative to other heavy industries (figure 11).

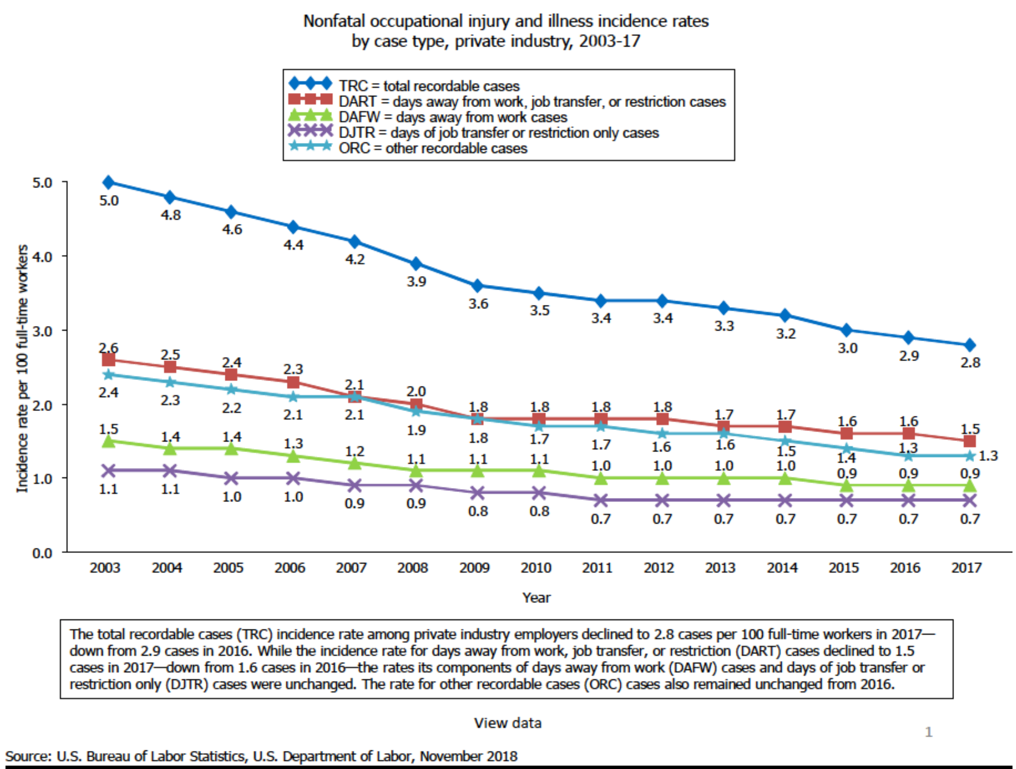


Figure 10: US Safety Performance Metrics: 2003-2017

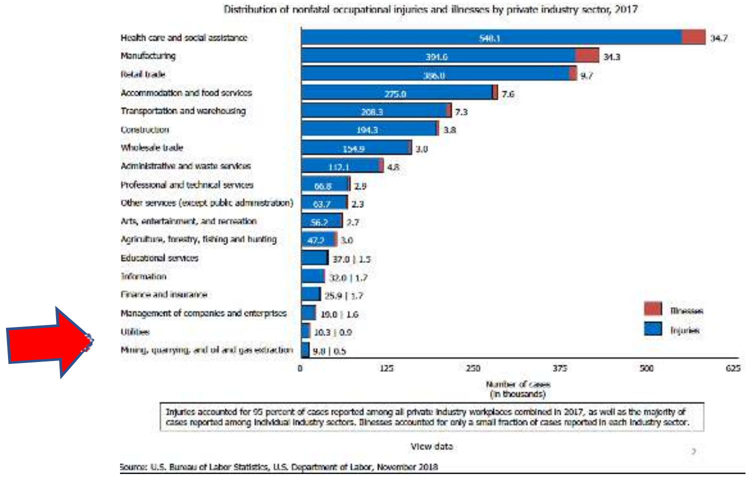


Figure 11: US 2017 Safety Performance Metrics by Industry

Occupational safety metrics are one parameter for tracking utility safety performance. In general, utilities have shown an exemplary record in occupational safety as it has been a management and employee priority for some time.

Table Two: California Utility Safety Performance Metrics for Southern California Edison

Safety Performance Metrics/SCE (Due March 31, Staff Review Sept 7)	Risks	Category	Type of Metric, leading or lagging
Transmission & Distribution Overhead Wires Down	Wildfire	Electric	Lagging
Transmission & Distribution Overhead Wires Down - Major Event Days	Wildfire	Electric	Lagging
911 Emergency Response - Electric (Response within 1 hour)	Wildfire	Electric	Lagging
Fire Ignitions	Wildfire	Electric	Lagging
Employee Serious Injuries and Fatalities (Employee-SIF)	Employee Safety	Injuries,Fatalities(O)	Lagging
Employee Days Away, Restricted and Transfer (DART) Rate	Employee Safety	Injuries,Fatalities(O)	Lagging
Contractor OSHA Recordables Rate	Contractor Safety	Injuries,Fatalities(O)	Lagging
Contractor Serious Injuries and Fatalities (Contractor -SIF)	Contractor Safety	Injuries,Fatalities(O)	Lagging
Contractor Lost Work Day Case Rate	Contractor Safety	Injuries,Fatalities(O)	Lagging
Public Serious Injuries and Fatalities (Public - SIF)	Public Safety	Injuries,Fatalities(O)	Lagging
Helicopter/Flight Incident	Public Safety	Vehicle	Lagging
injuries, fatalities (O) - occupational injuries and fatalities			

Safety Metrics in California's New Utility Safety Framework

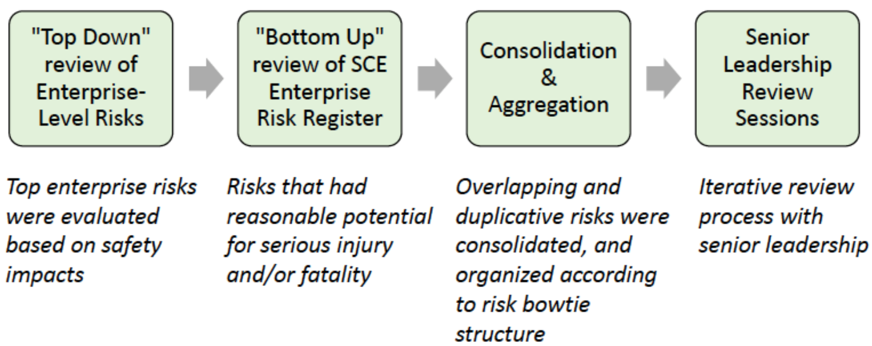
A recent Commission Decision, D.19-04-020, adopted April 25, 2019, adds to the new utility safety framework in California by enhancing safety performance with a new reporting requirement. This program will allow the Commission to track utility progress in meeting key safety goals and metrics.

The reporting on key safety performance metrics (see Table Two above) adopts 11 specific safety metrics that will apply to SCE. SCE will be required to report annually on these metrics. Most of these metrics have already been reported by utilities in separate reports. Now all safety metrics must be reported in one comprehensive report. It also requires further development of certain metrics that will help in the assessment and evaluation of safety management and culture. It has been noted that the Commission has lacked tools for systematically evaluating whether utility actions and spending are improving, and their impact on safety outcomes.

To demonstrate the value of this aspect of the new California framework, a pilot evaluation of one risk, contact with energized equipment, uses data on SCE safety performance metrics to examine SCE's proposed mitigation plan. This is the type of systematic data analytics that will result from more reporting, assessment, and evaluation of utility safety programs by the Safety and Enforcement Division.

4 ASSESSMENT OF SCE UTILITY RISKS

a. IDENTIFYING UTILITY RISKS



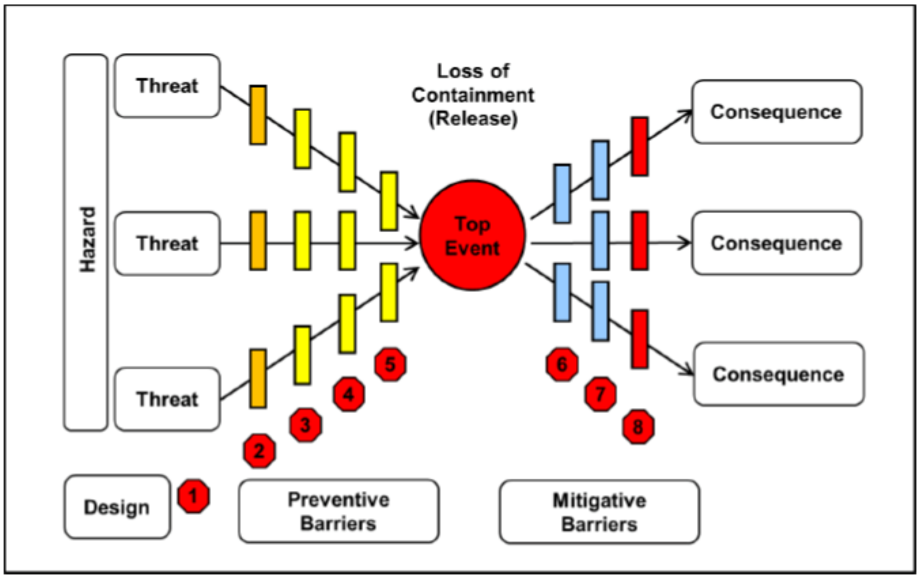
) Source: SCE RAMP Report)

Figure 12: SCE Risk Identification and Analysis Process

The SCE RAMP Report uses the above flow diagram to describe its risk identification analysis process. With a combined "Top Down" review and "Bottom Up" review of its risk register, SCE management then culls those safety risks it deems as not significant and identifies the remaining risks as its priority safety concerns.

Once identified, to better describe a risk and its associated drivers and consequences, SCE breaks it down with what is referred to as a risk bowtie analysis (see figure 13). Consistent with SMAP protocols, SCE maps the progression of a risk from its drivers to the risk event and connects it to outcomes and associated consequences. In this parsing, a baseline risk is evaluated, and each input parameter or risk driver then quantified. The frequency of occurrence, outcome likelihood and consequence impacts were included in determining the contribution of a driver. Next, mitigation effects are then evaluated and scored for how each control (required mitigation) or proposed mitigation affects exposure, frequency, likelihood or impacts.

Process Safety Metrics: Guide for Selecting Leading and Lagging Metrics



(Source: Center for Chemical Process Safety)

Figure 13: Risk Bowtie Diagram

For describing event impacts, consequences are measured in terms of four parameters: 1) fatalities, 2) serious injury, 3) reliability (customer minutes interrupted), and 4) direct financial impact to the utility. This bowtie analysis is further used to structure the subsequent probabilistic risk modeling, using these four factors to assess event impacts.

b. SCE Risk Modeling

In its RAMP Report, SCE conducts a statistical risk assessment to evaluate and compare its significant risks and mitigations. Using a Multi-Attribute Risk Score (MARS) approach, it attempts to replicate reality by statistical modeling of risk drivers that produce probabilistic outcomes via Monte Carlo simulation using off-the-shelf software. The result is a quantification of all risks, via a "risk score", a ranking of potential consequences in the form of fatalities, injuries, reliability, and utility financial impact, and an assessment of both high-impact, low frequency (HILF) risks, referred to as tail-average outcomes, and more likely or higher probability outcomes, describe as mean outcomes. Ideally, by evaluating a range of mitigated outcomes with this model, a utility can better identify appropriate mitigation plan in terms of maturity, robustness, and thoroughness.

With the recent SMAP settlement agreement, the modeling issues for the RAMP Report have been determined and SCE has incorporated relevant aspects of this agreement in its risk modeling. Any issue related to risk modeling going forward will be further addressed in future SMAP proceedings. This allows this review of the Report to focus on model outcomes and how they inform utility mitigation plans. (There is additional analysis of risk model factors in Appendix C.)

C. SCE Priority Risks

Once SCE completes its risk modeling, the risk assessment is completed with senior leadership reviewing the final results and determining the utility's top risks. In the RAMP Report, SCE identifies nine risks that have the most significant utility safety impacts. Those risks are shown below.

(SOURCE: SCE RAMP Report)

Figure 14: SCE Top Safety Risks

The results of the risk modeling are shown in the figures below. Figure 15 shows the MARS or risk scores for SCE's nine defined risks under the mean scenario. Under this scenario, SCE's modeling ranks the priority risks under standard operating procedures in the following order

- Contact with energized equipment
- Employee and contractor safety
- Wildfires
- Underground equipment failure

- Physical security
- Building safety
- Cyber attack
- Hydro asset safety

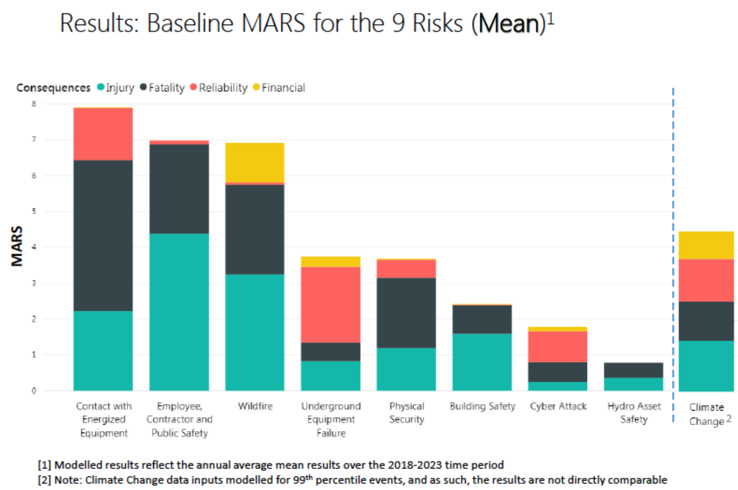


Figure 15: SCE Common (Mean) Safety Risks

For the tail-average or high impact, low probability scenario, the ranking of risks differs considerably from the mean scenario.

In this case, the ranking of risks is shown below -

- Wildfires
- Physical security
- Cyber attack
- Contact with energized equipment
- Employee and contractor safety
- Building safety
- Underground equipment failure
- Hydro asset safety

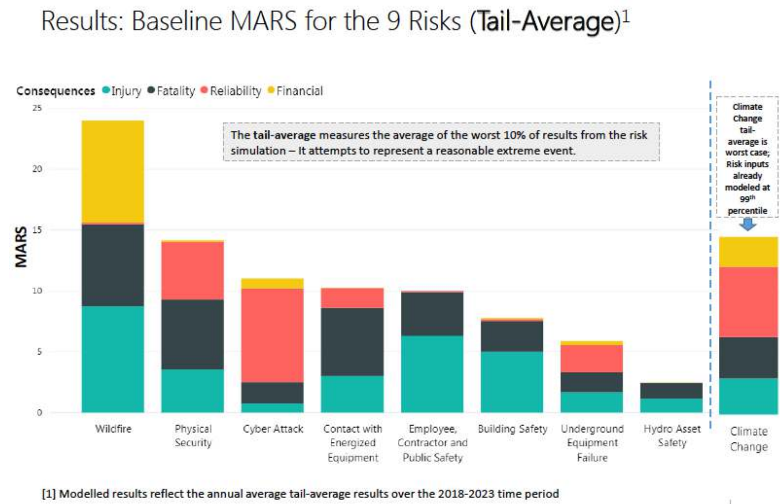


Figure 16: SCE Low Probability, High Impact (Tail-Average) Safety Risks

The two scenarios show differences in risk scores and order or prioritization of risks. While the tail-average scenario shows wildfire, physical security and cyberattack as the top three risks, the mean scenario shows contact with energized equipment as the top risk.

These model results do show that while it is valuable to have a MARS modeling approach, it is limited in fully capturing utility safety risks. For example, as discussed later in this Review, data provided in SCE's RAMP Report Working Papers show that incidents involving contact with energized equipment have dropped over the past five years and does not merit being ranked as high as it is by SCE's risk model. It is therefore advisable that the Commission consider these results when reviewing SCE's assessment of risks, but that the Commission must ultimately decide what it considers the top utility safety risks for a particular utility based on multiple sources of information involved in a GRC proceeding or other utility' safety proceeding.

5 SED Assessment of SCE Risks and Risk Ranking

a. Prioritizing Utility Risks

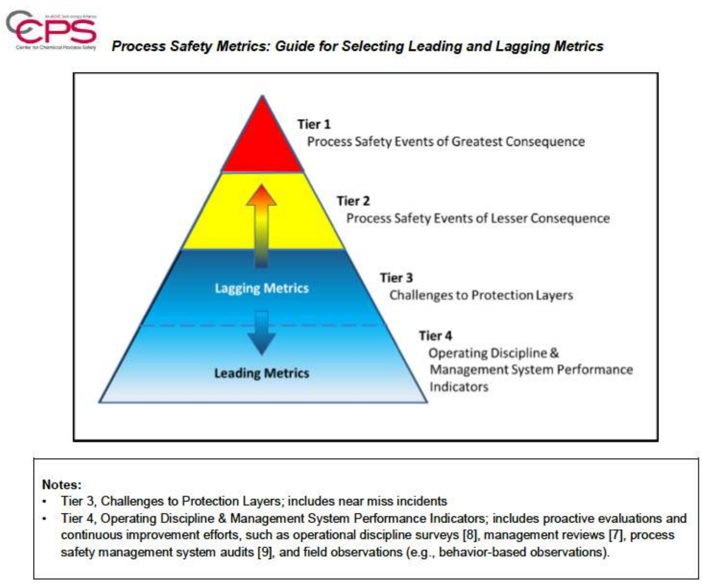


Figure 17: Process Safety Metric Pyramid

While the SMAP protocols have added a large set of new tools for utilities and the Commission to determine the best use of utility investment proposals, a final step that is not included in SMAP is the separation of risks into separate categories. In its Report, SCE identifies nine risks as most significant to utility safety. SCE risk modeling then shows various scores for each risk which seems to infer some type of order or priority. However, one of the limitations of this risk modeling is that while the risk scores are an indication of how risks relate to one another and how mitigations may impact those risks, these scores are not reliable enough to identify any particular prioritization.

Commonly in heavy industry, as shown above in Figure 17, a tiered approach is used for segregating their top risks based on potential consequences. This enables a clearer understanding of investment priorities and proposals. In 2006, the Center for Chemical Process Safety (CCPS) launched a project to develop better leading and lagging safety metrics. It resulted in the publication, Guidelines for Risk Based Process Safety, as part of a broader process safety management framework that included this hierarchy of risks and safety metrics. Safety risks are ranked on the pyramid according to their severity. High-consequence incidents are placed at the top, low-consequence incidents at the bottom. Part of the theory behind this approach is that low-consequence events can be a prelude to higher-consequence events.

For example, in a process industry, Figure 17 shows that Tier 1 events or risks are those of greatest consequence or impacts. Similarly, Tier 2 safety risks are events of lesser consequence and Tier 3 are those risks that are due to challenges to protection layers or changes in infrastructure or environmental conditions that make current mitigations insufficient to address current conditions. Tier 4 addresses operating discipline and management performance. These tiers are used to set priorities and identify performance metrics[14].

For the upcoming SCE GRC proceeding, this Review proposes that the Commission follow a similar model. For reviewing utility capital spending proposals, risks are ranked as follows -

Tier 1 risks are those risks that have catastrophic impacts or could lead to cascading failures.
Tier 2 covers operational risks that are part of the electric utility business.
Tier 3 risks for California electric utility industry is those associated with utility assets that are federally regulated. For SCE, this consists of its generation assets, hydro and nuclear. While transmission assets are also Federally regulated, due to SB 901, it is recommended that distribution and transmission asset wildfire risks be treated equally as Tier 1 risks.

The benefit of this tiered approach is that it can direct Commission resources to the most significant risks and also recognize when risks are being properly managed. With more focus on those risks with larger impacts, utility efforts can be situated to achieving sufficient reductions of the major risks while also being cognizant of standard operating risks. It also provides some order and organization to how the Commission addresses utility safety. The next sections describe SCE risks by tier and why SED believes this improves the Commission's ability to review and regulate utility safety projects.

b. Tier 1 SCE Utility Risks

Transmission and Distribution Wildfire Risks

For SCE, it is recommended that the Tier 1 utility risks be defined as 1) wildfire risks associated with SCE distribution and transmission assets and 2) flooding/mudslides. These risks have had significant impacts in recent years and warrant appropriate attention.

The SCE RAMP Report only addresses wildfire risks associated with its distribution assets. Given that it is known that transmission assets have been responsible for major wildfires and should be addressed in utility capital projects. While it is recognized that the Federal Energy Regulatory Commission (FERC) is responsible for the regulation and funding of SCE's transmission assets, SB 901 requires the CPUC to address wildfire risk for all electric assets. Therefore, for the upcoming GRC proceeding, it is recommended that SCE provide a full

[14] Center for Chemical Process Safety, "Process Safety Leading and Lagging Metrics," January 2011

accounting for activities related to transmission wildfire risks in conjunction with its efforts related to its distribution assets.

Figure 18: Tier 1 SCE Utility Safety Risks

Flooding/Mudslide Risks

In the aftermath of major wildfires in Southern California, associated flooding and mudslides impacted communities and infrastructure, including SCE assets. Due to the magnitude of these types of events, it warrants that this risk is given prominent consideration in the upcoming GRC proceeding with SCE providing an assessment of the risk of flooding and mudslides that could impact SCE assets and a description of how SCE is addressing this risk.

C. TIER 2 SCE UTILITY RISKS

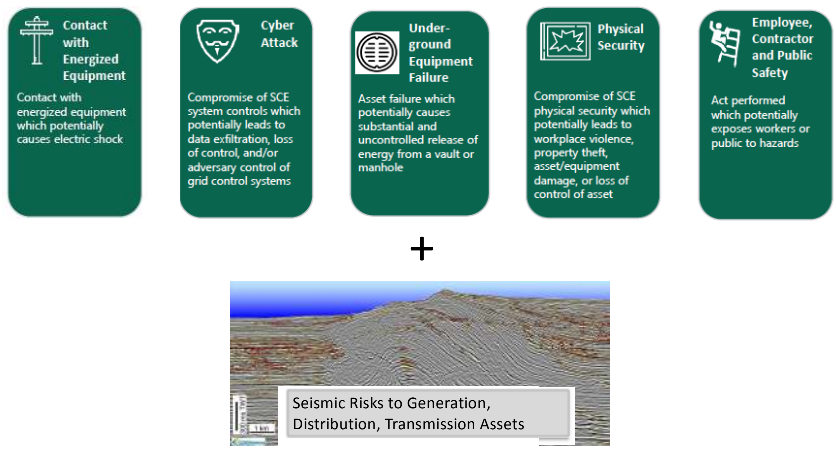


Figure 19: Tier 2 SCE Utility Safety Risks

For Tier 2 risks, it is recommended that this category consists of operational risks which are associated with owning and operating an electric utility. The risks in this category are

- Contact with energized equipment
- Cyber attack
- Physical security
- Underground equipment failure
- Employee and contractor safety
- Seismic risk

These risks are operational risks that must be addressed by a utility as part of its standard procedures. The seismic risk identified here is addressed in the SCE RAMP Report as an appendix. SCE has launched a Seismic Assessment and Mitigation Program to centralize and coordinate SCE's ongoing seismic projects for its infrastructure. While the Building Safety category identified by SCE, it includes building seismic safety which is outside the Commission's jurisdiction, but oversight of seismic safety of electric assets is within its authority. Similarly, SCE addresses seismic risk related to Hydro assets. For the upcoming GRC proceeding, SCE should provide more specific information on seismic risks associated with T&D assets.

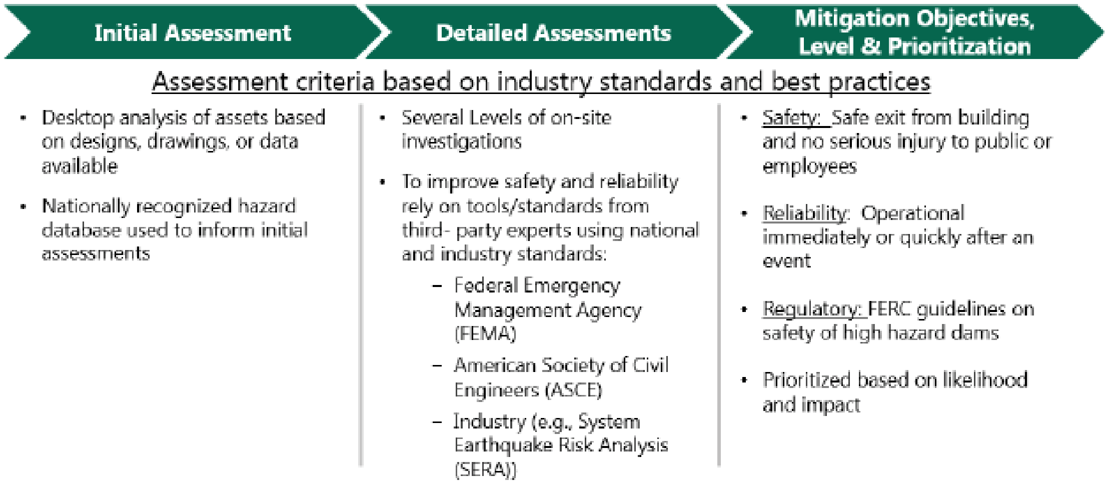


Figure 20: SCE Seismic Risk Assessment Process

d. Tier 3 - Federally Regulated Asset Safety

Figure 21: Federally regulated SCE Utility Safety Risks

Certain SCE assets are regulated by FERC and are not under the direct authority of the Commission. Yet having a full understanding of SCE safety culture and activities warrants that SCE describes how these risks are being addressed and proposed mitigations. Specifically, these risks are hydro asset safety and nuclear decommissioning, storage and transportation. While transmission assets are also regulated by FERC, this is discussed earlier as a Tier 1 risk.

6 SCE Proposed Mitigations

a. Mitigation of Catastrophic Risks

i. Wildfire Mitigation Plan

Table Three: Southern California Edison Wildfire Mitigation Planned Expenditures

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Mean Value (MARS)		Tail Average (MARS)		
		Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE	
	Wildfire (Amendment)									
C1	Overhead Conductor Program (Bare & Covered)	2018	2023	$102	x	0.09	0.0009	0.3	0.003	
C2	FR Overhead Distribution Transformer	2018	2023	$81	x	0.06	0.0007	0.18	0.0022	
M1	Wildfire Covered Conductor Program	2018	2023	$1,161	x	1.64	0.0014	5.28	0.0045	Double Count CWE
M2	Remote-controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$28	$3	0.97	0.0311	3.35	0.1075	
M3	PSPS Protocol and Support Functions	2018	2023	x	$21	1.90	0.0892	6.66	0.3119	
M4	Infrared Inspection Program	2018	2023	x	$3	0.29	0.1029	0.95	0.3321	Double Count CWE
M5	Expanded Vegetation Management	2018	2023	x	$370	0.38	0.001	1.23	0.0033	
M7	Enhanced Situational Awareness	2018	2023	$31	$26	0.84	0.0149	3.19	0.0561	
M8	Fusing Mitigation	2018	2020	$68	$23	0.23	0.0025	0.74	0.0081	
M9	Fire Resistant Poles (M1 Scope)	2018	2023	$137	x	0.60	0.0044	2.26	0.0165	
				$1,609	$447	7.02	0.0034	24.14	0.0117	

In CalFire's recent 45-day report[15] to the Governor, it notes that California's forest management efforts have not kept pace with growing wildfire risks -

> The State's collective forest management work has been inadequate to improve the health of millions of acres of forests and wildlands that require it. It is estimated that as many as 15 million acres of California forest need some form of restoration.

The collective wildfire risk that utilities bear in 2019 has never been higher and has substantially increased over the past two years. While wildfires are a natural part of our landscape, the fire season in California and the West is beginning earlier and ending later each year, with catastrophic impacts. The length of fire season is estimated to have increased by 75 days in parts of the State including within SCE service territory. This increase across the Sierras corresponds with an increase in the extent of forest fires[16,17].

The report notes the realities that it will take a committed effort over time to restore forest health and resilience, with focused and deliberate action vulnerable communities can be protected and improve forest and fuels conditions with the goal of a more moderate and healthier wildfire cycle that can coexist with Californians.

---

[15] CalFire, Community Wildfire Prevention & Mitigation Report, February 2019

[16] Ibid

[17] Westerling, A.L., Wildfire Simulations for California's Fourth Climate Change Assessment: Projecting Changes in Extreme Wildfire Events With A Warming Climate, August 2018

This Review examines the proposed mitigation plan and alternatives set forth by the utility in its March 14, 2019 RAMP amendment. This Review does not examine nor take into account SCE's Wildfire Mitigation Plan. The amendment specifically updated quantitative data in order to be consist with the SCE Grid Safety and Resiliency Program filed on December 26, 2018. However, the amendments did not materially change the proposed mitigation plan.

In its Report, the utility does not discuss recent wildfires impacts on utility assets and operations. It also does not provide any sense of what expected future impacts could be on utility assets and operations. Such information would allow for the Commission to better assess how sufficient the utility's mitigation plan is in meeting long-term resilience standards.

In the risk assessment described in the RAMP Report, the monte carlo simulations are for service territory risks solely on their distribution assets, risks averaged SCE's 50,000 square mile service territory. Wildfire risks due to transmission assets are not addressed in this RAMP Report. It should be noted that CalFire has designated approximately 100 vulnerable communities within SCE's service territory and identified priority landscapes for reducing wildfire threats as shown in Figure 22 below. It would be more informative for the Commission if SCE's mitigation plan proposal specifically addresses how its mitigations will reduce wildfire risks for vulnerable communities and priority landscapes. With the upcoming GRC considering funding through 2023, it is essential that utility and CalFire wildfire efforts support the collective goal of improved forest health and reduced wildfire risk.

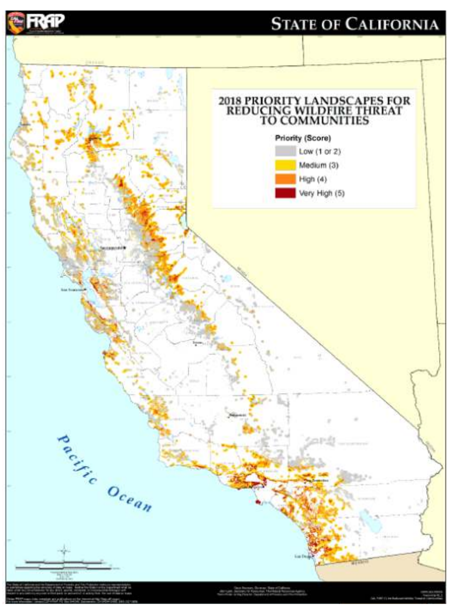


Figure 22: Priority Landscapes for Reducing Wildfire Threat

Yet SCE is providing community grants of up to $25,000 for this summer. It is presumed that these community efforts would have impacts on wildfire risks and should be accounted for in SCE's mitigation plan.

Edison International Fire-Safe Community Grants

Grant opportunity in Southern California Edison service areas

FOR MORE INFORMATION

CONTACT

Sandra Lyons
(909) 906-9472
slyons@cafiresafecouncil.org

Amber Gardner
(916) 256-3337
agardner@cafiresafecouncil.org

More information available on our website:

www.cafiresafecouncil.org

No project is too small, there is no minimum grant amount.

Acknowledgements

Funding for this grant program is provided by a grant from Edison International

March 15, 2019

California Fire Safe Council (CFSC) and Edison International, parent company of Southern California Edison (SCE), are pleased to announce a joint collaboration to provide grants to communities in Southern California Edison service areas. The objective of this project is to provide small grants for community fire prevention and preparedness projects. Funding may be used to further enhance community projects such as: capacity building, community outreach/preparedness, and permit-ready hazardous fuel reduction projects. Successful projects are easy-start, easy-finish, with a simple closing report to document project success.

Examples of projects may be in the following three priority areas:

Capacity Building
- Capacity building for new or emerging Fire Safe Councils.
- Organizational infrastructure and/or equipment.

Community Outreach/Preparedness
- Developing or acquiring fire safety educational publications.
- A community-area risk assessment to identify possible mitigation projects.
- Community workshops on Hardened Homes and/or Defensible Space.
- Help developing a CWPP after a community risk assessment is done.

Hazardous Fuel Treatment
- A chipper day or weekend for the community to chip brush and branches.
- Defensible space assistance for special needs populations.
- Permit-ready fuel treatments.
- Purchase of small equipment, such as chippers or chainsaws.

Other projects of this nature will be considered as well.

Funding Available:
No project is too small. Maximum grant amount of $25,000.

Program Eligibility:
Funded projects are required to be within SCE service areas. No individuals or for-profit entities may apply. Applicants are encouraged to collaborate with their local community-based Fire Safe Council or similar organization.

Timeline:
Open until filled. Final application deadline is **April 15, 2019 at 5 p.m.**
All work is required to be completed and reports submitted by **September 1, 2019.**

To Apply:
Login at https://cafiresafecouncil.org/zoomgrantslogin/ to create a new account and select "**2019 SCE Fire Safe Community Grants**" grant program to begin.

Figure 23: SCE Fire-Safe Community Grant Solicitation

Table Four: Vulnerable Communities by Region[18]

City	County	%
Inland Deserts		
Banning	Riverside	
Beaumont	Riverside	
Calimesa	Riverside	
Canyon Lake	Riverside	
Cathedral City	Riverside	
Corona	Riverside	
Desert Hot Springs	Riverside	
Hemet	Riverside	
Juipa Valley	Riverside	
Lake Elsinore	Riverside	
Menifee	Riverside	
Norco	Riverside	
Palm Desert	Riverside	
Palm Springs	Riverside	
Perris	Riverside	
Rancho Mirage	Riverside	
Riverside	Riverside	
San Jacinto	Riverside	
Temecula	Riverside	
Wildemar	Riverside	
Big Bear Lake	San Bernardino	
Chino Hills	San Bernardino	
Colton	San Bernardino	
Fontana	San Bernardino	
Grand Terrance	San Bernardino	
Hesperia	San Bernardino	
Highland	San Bernardino	
Loma Linda	San Bernardino	
Rancho Cucamonga	San Bernardino	
Redlands	San Bernardino	
San Bernardino	San Bernardino	
Upland	San Bernardino	
Yuicapa	San Bernardino	
Yucca Valley	San Bernardino	
Los Angeles		
Aliso Viejo	Orange	
Anaheim	Orange	
Brea	Orange	
Dana Point	Orange	
Fullerton	Orange	
Irvine	Orange	
La Habre	Orange	
Laguna Beach	Orange	
Laguna Niguel	Orange	
Laguna Woods	Orange	
Lake Forest	Orange	
Mission Viejo	Orange	
Newport Beach	Orange	
Orange	Orange	
Rancho Santa Marg	Orange	
San Clemente	Orange	
San Juan Capistrand	Orange	
Tustin	Orange	
Villa Park	Orange	
Yorba Linda	Orange	
Caraillo	Ventura	
Fillmore	Ventura	
Moorpark	Ventura	
Ojai	Ventura	
Santa Paula	Ventura	
Simi Valley	Ventura	
Thousand Oaks	Ventura	
Ventura	Ventura	
Lompoc	Santa Barbara	
Santa Barbara	Santa Barbara	

Table Five: SCE Proposed Wildfire Mitigation Plan Proposed Measures for 2019

	SB901 Activitiy Identifier	Activity/Program	Capital Cost 2019 ($M) ($Nominal)(2019 Goal)	Capital Cost 2019 ($M) ($Nominal)(2019 Expansion/Acceleration)	O&M Cost 2019 ($M) ($Nominal)(2019 Goal)	O&M Cost 2019 ($M) ($Nominal)(2019 Expansion/Acceleration)
D&C	AT-1	Alternative Technology Pilots	0.2	NA	NA	NA
	AT-2	GSRP Wildfire Mitigation Program Study	NA	1.4	0.6	NA
	AT-3	Alternative Technology Evaluations	NA	NA	0	NA
	AT-4	Alternative Technology Implementation	NA	NA		NA
I&M	IN-1	Distribution Enhanced Overhead Inspections and Remediation in HFRA	102.8	NA	144.9	NA
	IN-2	Transmission Enhanced Overhead Inspections and Remediation in HFRA	9.9	NA	25	NA
	IN-3	Ouality Oversight/Quality Control of EOI	NA	NA		NA
	IN-4	Infrared Inspection of energized overhead distribution facilities and equipment	NA	NA	0.5	NA
	IN-5	Infrared inspection, corona scanning and high definition imagery of energized overhead transmission facilities and equipment	NA	NA	5.7	NA
	NA	AGP - Drvie by of overhead distribution facilities and equipment	NA	NA		NA
D&C	NA	Automatic Reclosers Replacement Program	2.4	NA	NA	NA
	NA	Capacitor Bank Replacement Program	18.1	NA	NA	NA
I&M	NA	Detailed inspection of Transmission facilities and equipment	NA	NA	5.7	NA
	NA	Deteriorated Pole Program	251.2	NA	NA	NA
	NA	Insulator Washing	NA	NA	1.2	NA
	NA	IPI - intrusive pole inspections to identify rot and decay	NA	NA	6.1	NA
	NA	ODI - Detailed inspections of Distribution overhead faciltieis and equipment	NA	NA	8.6	NA
D&C	NA	Overhead Conductor Program	143.9	NA	NA	NA
	NA	PCB Transformers Replacement Program	1.5	NA	NA	NA
OP	NA	Performance of joint patrols with fire agencies	NA	NA		NA
I&M	NA	Pole Brushing	NA	NA		NA
	NA	Pole Loading Program	NA	NA	26.4	NA
OP	NA	PSPS/De-energization Protocol Support Costs	NA	NA	4.3	NA
I&M	NA	Road and Right-of-Way Maintenance	NA	NA	3.9	NA
	NA	Substation Inspection and Maintenance	NA	NA	2.2	NA
	NA	Supplemental inspections of HFRA	NA	NA	69.1 Distribution, 11.3 Transmission	NA
	NA	Transmission Line Rating Remediation	157.9	NA	8.2	NA
	OP-1	Annual SOB 322 Review	NA	NA		NA
OP	OP-2	Wildfire Infrastructure Protection Team Additional Staffing	NA	NA	0.5	NA
	PSPS-1	De-Energization Notifications	NA	NA	1.3	NA
SCA	SA-1	Additional Weather Stations	5.4	6	0.6	0.6
	SA-2	Fire Potential Index Phase II	NA	NA	0.6	NA
	SA-3	Additional HD Cameras	2.3	2.8	2.6	4.3
	SA-4	High-performing Computer Weather Modeling System	3.8	NA	0.1	NA
	SA-5	Develop Asset Reliability and Risk Analytics Capability	0.5	NA	NA	NA
D&C	SH-1	Covered Conductor	47.4	133.1	1.0	2.7
	SH-2	Evaluation of Undergrounding in HFRA	0	3.1	0	0.1
	SH-3	Composite Poles and Crossarms	5.1	15.6	0.1	0.3
	SH-4	Branch Line Protection Strategy	46.1	52.3	0.9	1.1
	SH-5	Remote Controlled Automatic Reclosers Installations	4.9	NA	0.1	NA
	SH-6	Remote Controlled Automatic Reclosers Setting Updates	NA	NA	0.3	NA
	SH-7	Circuit Breaker Fast Curve	9.1	NA	0.2	NA
I&M	VM-1	Hazard Tree Mitigation Program (HTMP)	NA	NA	25.5	56.9
	VM-2	Expanded Pole Brushing	NA	NA	0.9	9.6
	VM-3	Expanded Clearance distances at time of maintenance	NA	NA	28.0	NA
	VM-4	DRI quarterly inspections and removals	NA	NA	41.5	NA
	VM-5	LIDAR Inspections of Tranmission	NA	NA	3.7	NA
		TOTALS	812.5	214.3	351.2	75.6

For the Wildfire Mitigation Plan prescribed by SB 901, the CPUC asked the utilities to submit a proposed budget for their plan consisting of all mitigation tasks. In addition, the utilities had to identify whether the mitigation measure consisted of one of the following categories:

1. Design and construction
2. Inspection and Maintenance
3. Operational Practices
4. Situational/Conditional Awareness
5. Response and Recovery

For SCE, their portfolio of mitigation measures leans heavily on inspection and maintenance but with a sizable investment in design and construction tasks which includes automatic reclosers

[18] Does not include Los Angeles County

replacement and overhead conductor program. Interestingly, the largest budget is for the Deteriorated Pole Program.

Table Six: Comparison of Proposed WMP Budgets by Task Type versus SCE RAMP Proposed Wildfire Budget

		Wildfire Mitigation Plan (2019)			RAMP Wildfire Mitigations (2018-2023)		
WMP Color Legend		no. of tasks	Capital ($M)	O&M ($M)	no. of tasks	Capital ($M)	O&M ($M)
Design & Construction (D&C)		15	$278.7	$3.2	5	$1,509.0	$3.0
Inspection and Maintenance (I&M)		22	$521.8	$334.1	3	$68.0	$396.0
Operational Practices (OP)		2	$0.0	$6.1	1	$0.0	$21.0
Situational/Conditional Awareness (SCA)		5	$12.0	$3.9	1	$31.0	$26.0
Response and Recovery (R&R)			$0.0	$0.0	0	$0.0	$0.0
		44	$812.5	$347.3	10	$1,608.0	$446.0

In California's new utility safety framework that specifically addresses wildfire risk, past utility practices must be transformed to better utilize concurrent efforts by other parties, private and public. This is no better demonstrated than with SCE's proposed vegetative management efforts. While this report is vague in details on how or where SCE will address the landscape within its service territory, the upcoming GRC filing will give the utility an opportunity to further describe its proposed mitigations over the next four years.

Table Seven: Comparison of California IOUs Wildfire Mitigation Plans By Type of Mitigation

Comparison of WMPs		SDG&E		PG&E		SCE	
Type of Mitigation		**no. of tasks**	**% 0f Total Budget**	**no. of tasks**	**% of Total Budget**	**no. of tasks**	**% of Total Budget**
Design & Construction (D&C)		13	23	9	21	15	34
Inspection and Maintenance (I&M)		22	39	11	26	22	50
Operational Practices (OP)		7	12	12	28	2	5
Situational/Conditional Awareness (SCA)		7	12	8	19	5	11
Response and Recovery (R&R)		8	14	3	7	0	0
Total # of Mitigation Measures		**57**		**43**		**44**	

One factor that the Commission should consider in the upcoming GRC proceedings is the recent US Forest Service research in California. It offers new insight into how a technique known as "variable-density thinning," combined with an understanding of historical local fire patterns reduces tree mortality while enhancing the restoration of forest health.

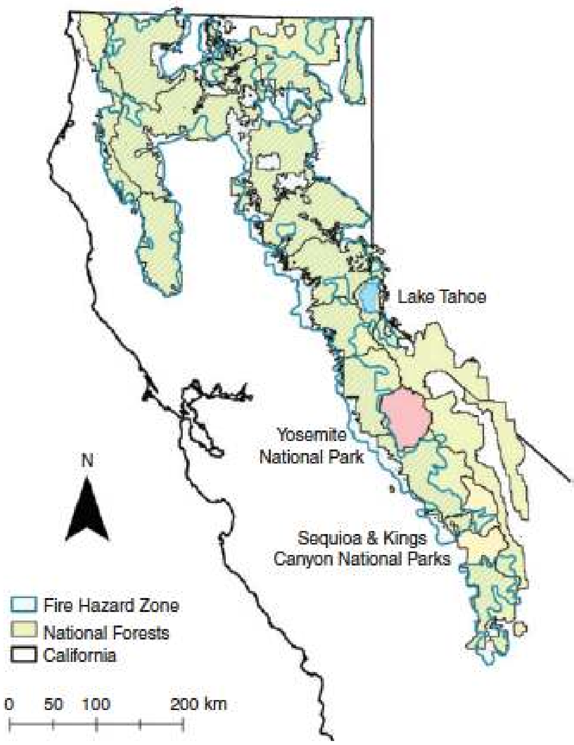


Figure 24: Map of Study Area for USFS Research on California Vegetation Management

This consideration is particularly important since this research includes USFS lands just east of Sonora, CA in the Stanislaus National Forest in Tuolumne County. In a section of the central Sierra Nevada mountain range is an area where all trees have been mapped and documented since 1929, making in the most studies forest in the US. This "variable density thinning" study, was initiated on 240 acres in 2009. Another study comparing different thinning and prescribed fire treatments for alleviating mortality of large pines was installed on 135 acres in 2009[19]. Overall, Figure 24 shows that 16 specific areas[20] within the State have been studied, including areas with SCE service territory. The scope of this research included comparing thinning to a variable spatial structure based on the historic stand structure and thinning with or without prescribed fire. Obviously, since the findings from this now decade-long effort by the USFS has direct implications for California's natural resources, vulnerable communities, and IOUs, it is appropriate for the Commission to require electric utilities to incorporate the best science, technology and practices.

[19] Collins, Brandon M, et al, "A Quantitative Comparison of Forest Fires in Central and Northern California Under Early (1911-1924) and contemporary (2002-2015) Fire Suppression", **International Journal of Wildland Fire**, 2019
[20] Mendocino, Si Rivers, Shasta-Trinity, Klamath, Modoc, Lassen, Plumas, Tahoe, Lake Tahoe Basin Management Unit, El Dorado, Humboldt-Toiyabe, Stanislaus, Inyo, Sierra and Sequoia, portions of Yosemite, Sequoia and Kings Canyon National Parks.

In California's new framework, the Commission should require utility vegetation management programs that are consistent with these findings and demonstrate how they are in alignment with current fire science knowledge and best forest management practices. In SCE's GRC filing, it would be informative for the Commission if it included how such programs inform SCE's efforts in wildfire safety.

Similarly, San Diego Gas and Electric's award-winning wildfire safety program currently has five meteorologists on staff, a supercomputing program, and the densest privately-owned weather network in the country. Collecting almost 200,000 data points a day from 177 weather stations and reporting at unprecedented 10-minute intervals has fueled an analytics program and cutting-edge real-time indices that characterize the environmental threat of wildfires and inform utility personnel, first responders and vulnerable communities. SDG&E leverages these resources and indices to support pre-event and real-time decision-making to mitigate wildfire risk during critical weather incidents. It would be informative if SCE describes in its upcoming GRC filing how it intends to develop its wildfire safety program during the GRC period of 2018-2023 and beyond that reflects industry best practices and emerging standards. More comprehensive recommendations on wildfire safety are included in the last chapter of this report along with additional recommendations in Appendix C.

ii. Flooding/Mudslides

After the 2017 wildfires in Southern California, subsequent mudslides resulted in 15-foot high debris flows that resulted had a significant impact in terms fatalities, injuries, property and infrastructure damage. Included in the damage was electric distribution and transmission assets. The SCE RAMP Report does not address this risk. Given the increased risk of flooding and mudslides in light of recent wildfire seasons that could impact communities and utility infrastructure, SCE needs to assess the potential risks of flooding and mudslides on their assets that are within the landslide risk zones designated by the California Geological Survey on their website.

With the significant impacts of flooding and mudslides on Southern California communities, SCE should submit additional information on how they are addressing this risk in its 2019 GRC filing. In that filing, SCE should submit a report on the impact that flooding and mudslides have had on their infrastructure in the past five years. In addition, SCE should submit a supplemental risk assessment looking solely at the risk of flooding and mudslides in the designated landslide zones and potential impacts to SCE infrastructure.

Figure 25: Map of flooding and mudslides in Montecito, CA

b. Mitigation of Operational Risks

i. Contact by Energized Equipment Mitigation Plan

Table Eight: Proposed Mitigation for Contact by Energized Equipment

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE
	Contact W Energized Equipment (Amendment)						
C1	Overhead Conductor Program (DCP)	2018	2023	$715	x	3.22	0.0045
C1a	Overhead Conductor Program (DCP) Utilizing Targeted Covered Conductor	2021	2023	$34	x	0.10	0.0029
C2	Public Outreach	2018	2023	x	$33	0.42	0.013
M4	Infrared Inspection	2018	2023	x	$3	1.04	0.3627
M5	Wildfire Covered Conductor Program	2018	2023	$1,161	x	0.54	0.0005
	TOTAL			**$1,910**	$36	5.32	0.0027

Table Eight above shows SCE's proposed mitigation plan for a Tier 2 risk, contact by energized equipment. At first glance, it appears that SCE is proposing a capital budget of almost $2 billion. Specifically, $ 1.91 billion for the five proposed mitigations. However, the last two listed mitigations, infrared inspection and wildfire covered conductor program, are also included in the wildfire mitigation proposed capital projects and therefore the actual capital budget for the mitigations addressing this risk is $749 million.

Figure 27 below provides the annual performance for SCE in terms of contact with energized equipment. Using data provided in SCE's RAMP working papers, the highest number of injuries and fatalities in the past five years was in 2014. Since that time the number of injuries has been cut in half as have fatalities. While not specifically discussed in the SCE RAMP Report, this metric supports the occupational safety metrics that in some areas, SCE's safety efforts have been successful and should not be ignored. Therefore, continued capital spending at current levels may be justified but any proposed increase to reduce safety risks should be accompanied by a detailed risk assessment that shows how and why this risk is increasing with their service territory. (See Appendix C for further analysis related to Contact with Energized Equipment (CEE) compliance and control programs and SCE's CEE risk assessment.)

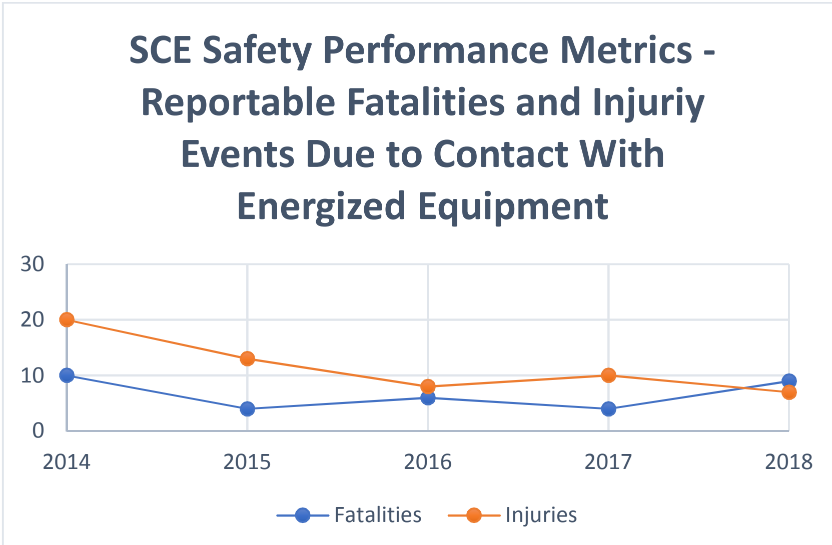


Figure 27: Contact with Energized Equipment - Recent SCE History

Safety Performance Metrics – Contact with Energized Equipment

To demonstrate how risk analytics can provide valuable insight into proposed mitigation plans, SED examined the public safety risk of contact with energized equipment. Using the CPUC Reportable Injuries and Fatalities Reports from 2014-2018 as provided by SCE in its RAMP work papers, insights were gained into risks, drivers and whether a mitigation was metered based on recent safety performance evidence.

Taking an evidence-based approach, all information was tabulated by year as shown below.

Table Nine: CPUC Reportable Injuries and Fatalities by Risk Driver, 2014 - 2018

	2014		2015		2016		2017		2018		TOTALS	
cause/year	No. of Injuries	No. of Fatalities	No. of Injuries	No. of Fatalities	No. of Injuries	No. of Fatalities	No. of Injuries	No. of Fatalities	No. of Injuries	No. of Fatalities	No. of Injuries	No. of Fatalities
maintenance - tree trimmer	0	3	1	0	4	0	0	0	1	1	6	4
maintenance - other	5	2	1	0	3	0	3	0	0	0	12	2
aircraft accident	2	1	1	0	0	2	2	2	0	6	5	11
downed line	4	3	0	1	0	1	2	1	0	0	6	6
ag accident	1	0	1	0	1	0	0	0	0	0	3	0
digging accident	3	0	4	0	0	2	1	0	4	0	12	2
mylar balloon	0	0	0	0	0	0	0	0	1	0	1	0
Physical Security - vandalism	6	1	1	2	0	0	2	0	2	0	11	3
Physical Security - metal theft	1	0	0	1	0	1	0	0	0	0	1	2
Physical Security - Suicide/Attempted	0	2	1	1	0	1	0	1	0	0	1	5
Miscellaneous	2	0	1	0	0	1	0	0	0	1	3	2

This table shows that over the past five years, there have been a total of 61 injuries and 37 fatalities. From this analysis, there were 11 identified drivers. For sake of classification, these drivers are defined below

1. Maintenance – tree trimmer: There is a general impression that tree trimmers have a higher risk than other maintenance and construction contractors.

2. Maintenance – other: Maintenance and construction contractors who are in proximity of powerlines. Includes, roofers, builders, and firefighters.

3. Aircraft accident: small powered aircraft including airplane, helicopter, and hang glider'

4. Downed line: direct contact with an energized downed powerline resulting in injury or fatality

5. Ag accident: contact with energized equipment during agricultural activity

6. Digging Accident: contractor excavating into street surface and contacting energized underground line

7. Mylar Balloon: mylar balloon contact with energized equipment directly resulting in injury or fatality

8. Physical Security- vandalism: Vandalism of utility electric assets resulting in contact with energized equipment and injury or fatality

9. Physical Security – metal theft: Metal theft activity resulting in contact with energized equipment and injury or fatality

10. Physical Security – Suicide/Attempted: Act of suicide or attempted suicide resulting in contact with energized equipment and injury of fatality

11. Miscellaneous: incident that does not fit other 10 categories

The data shows that safety performance for contact with energized equipment has improved over the past five years. Also note that for every year except 2016 and 2018, injuries out number fatalities and for those two years the number was equal for those two metrics. Also note that contrary to popular belief, tree trimmers are not the major driver of this risk. The risk seems to be spread evenly across these 11 drivers fairly evenly. The exception is those years where there are small increases in digging accidents. Also, physical security events are drivers but even these events are typically no more than 2 injuries annually.

In terms of injuries, risk analysis above shows that cumulatively over last five years digging accidents and maintenance workers other than tree trimmers were the two biggest drivers. Physical security incidents in the form of vandalism was a close third. Aircraft accidents have been the leading cause of fatalities in that same time period.

2014 had a peak of 24 injuries and 12 fatalities. In recent years there have been no more than 10 injuries and eight fatalities. For its proposed mitigation plan for this risk, SCE proposes five mitigation measures. They are –

Table Ten: Proposed Mitigations and Percentage of Proposed CapEx Budget

Proposed Mitigation	% of Total Proposed CapEx Budget
Overhead Conductor Program(D&C)	37
Overhead Conductor Program Utilizing Targeted Covered Conductor (D&C)	2
Public Outreach	0 (O&Mex)
Infrared Inspection	0 (O&Mex)
Wildfire Covered Conductor Program (D&C)	61

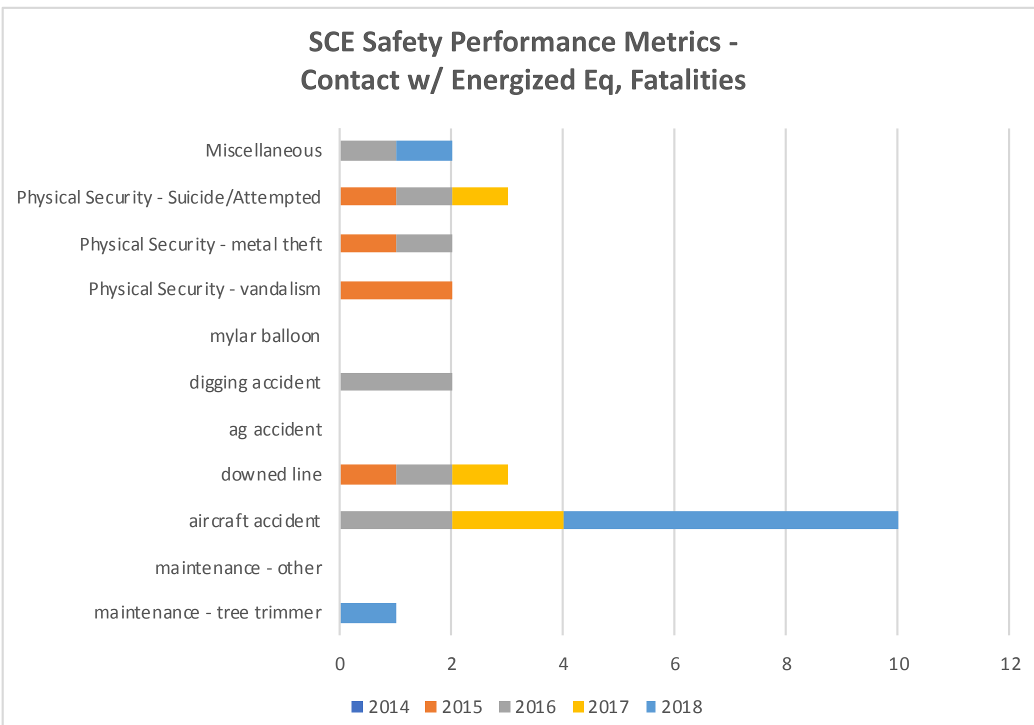


Figure 28: Fatalities due to contact with energized equipment, 2014-2018

Similar to the wildfire mitigation plan in this RAMP Report, the mitigation plan for this risk is entirely built on design and construction projects solely focused on the installation of covered conductors. But it is not apparent how this will impact aircraft accidents. For a total budget of almost $2 billion, would the proposed $33 million of public outreach have an equal if not greater likelihood of reducing this risk? SCE's GRC filing needs to better explain how these three mitigations address the 11 drivers and their associated impacts.

In the context of SCE's 2015 GRC and 2018 GRC, the high priority and high cost Pole Loading & Deterioration Pole Replacement Programs, that were put in place to minimize safety risks including wildfire risks, were not included in the Wildfire RAMP chapter. SCE also did not include pole drivers for Wildfire triggering events at all in its RAMP. As discussed further in the Appendix C, SCE's Wildfire & Contact with Energized Equipment Risk Assessments, risk reduction analysis including Risk Spend Efficiency (RSE) calculations would be most appropriate for decision-makers to be able to assess programs based on SCE's internal standards based on safety risks and costs even for programs that SCE deems to be compliance programs. Additionally, it behooves SCE to include which triggering events these high cost pole replacement programs are mitigating and to do RSE calculations based on relevant triggering events based on actual historical event data. And similar to circuit (or line segment) risk spend efficiency analysis discussed further in Appendix C, perhaps pole related programs could be analyzed pole by pole with RSE calculations per pole.

Additionally, as further discussed in Appendix C, 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. More detailed RSE calculations by circuit or line segment could be valuable to determine where fault detection and/or system hardening measures provide the highest risk reduction benefits. Risk spend efficiency (RSE) calculations could be calculated by circuit or line segment since circuit prioritization has already been conducted by SCE for the WCCP proposed mitigation measure. RSE calculations by circuit or line segment could be conducted to provide decision makers a measure of how much risk would be reduced based on cost for each circuit or line segment. This could be done for the proposed WCCP mitigation measure and for other potential system hardening and other mitigation measures that could be deployed and/or implemented on that circuit or line segment (e.g. undergrounding, automatic reclosers, other electric power protection engineering mitigation measures, etc.).

Hence, SED believes that the Index Score calculated for the Wildfire Covered Conductor Program to prioritize circuits for implementation of deployments could be utilized in RSE calculations combined with average cost of covered conductor replacement per circuit or conductor mile. In the future, estimated project cost per circuit or line segment, rather than average program cost, would improve these risk spend efficiency calculations even more. More detailed analysis and recommendations related to contact with energized equipment, including tree trimming, arc flash, and grounding methodologies are included in Appendix C.

ii. UNDERGROUND EQUIPMENT MITIGATION PLAN

Table Eleven: SCE Underground Equipment Measures

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE
	Underground Equipment Failure								
C1	Cable Replacememt programs (WCR)	2108	2023	$601	x	0.44	0.0007	0.531	0.0009
C2	Cable Replacement Programs (CIC)	2108	2023	$368	x	2.22	0.006	2.851	0.0078
C3	UG Oil Switch Replacement Program	2108	2023	$110	x	0.16	0.0014	0.204	0.0019
M1	Cover Pressure Relief and Restraint (CPRR) Program	2019	2023	$68	x	0.86	0.0126	1.863	0.0274
	TOTAL			**$1,147**	x	3.67	0.0032	5.449	0.0048

SoCal Edison says mismanagement led to Long Beach outages

Another vault explosion and subsequent power outage left an estimated 30,000 people without power on Thursday, July 30, 2015.
Courtesy City of Long Beach Twitter account

Sharon McNary | November 17, 2015

Figure 29: Long Beach Outage Mitigation 2015

SCE owns 50,000 miles of underground primary distribution circuits that consists of voltages that are typically 4, 12 or 16 kilovolts (kV), constituting 1/3 of SCE's distribution system.

Regarding utility safety, the SCE RAMP Report notes five incidents since 2015 including Long Beach where multiple failures resulted in outages and major disruptions to that community. As previously discussed in this Review, while not discussed in the RAMP Report, SCE does have an aging underground infrastructure that will need to be addressed in future GRC proceedings. As identified by SCE, the primary risk driver is equipment failure.

As shown in Table Eleven, SCE proposed mitigations consist of cable replacement programs, an oil switch replacement program, and a manhole cover pressure relief and restraint program for over $1 billion. Since these proposed mitigations do not show specific details on locations and how this program would be implemented, it is difficult to assess whether it addresses the most vulnerable sections of SCE's underground distribution system. Particular for mitigation plans in excess of $1 billion, more detailed information is warranted. Also lacking is any discussion or proposal for system monitoring that would enable the utility to identify equipment that is most likely to fail and to address problem areas before they escalate into a situation similar to Long Beach in 2015. It would be constructive if SCE addresses these issues in its GRC filing in September.

iii. CYBERATTACK

Table Twelve: SCE Proposed Cybersecurity Mitigation

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE
	Cyberattack								
C1a	Perimeter Defense	2018	2023	$81	$35	1.51	0.013	9.13	0.079
C2a	Interior Defense	2018	2023	$48	$24	0.91	0.013	5.83	0.082
C3a	Data Protection	2018	2023	$31	$17	0.02	0	0.03	0.001
C4a	SCADA Cybersecurity	2018	2023	$20	$20	0.46	0.012	3.04	0.077
C5a	Grid Modernization Cybersecurity	2018	2023	$169	$34	1.41	0.007	9.28	0.046
	TOTAL			**$348**	$129	4.31	0.009	27.32	0.057

As discussed in the SCE RAMP Report, the Department of Homeland Security has reported that since 2009, organizations have experienced an average annual increase of 124% for ICS/SCADA[21] cybersecurity incidents. These attempts have not only increased in quantity, but also in sophistication, with advanced tactics that are specifically designed to exploit ICS/SCADA systems. Records show that for the period 2014-2016, there were 61 such incidents in the energy industry, with SCE estimated that 12% resulted in actual intrusion into control systems.

For the risk of cyberattack, SCE has proposed a cybersecurity mitigation plan that consists of five mitigations for a total proposed budget of $348 million in capital investments, $129 million in operating expenses from 2018 to 2023.

Of the five proposed mitigations, the highest capital investment is $169 million in the grid modernization cybersecurity category. Another $81 million in capital expense is proposed for the perimeter defense category. Both of these categories show the highest reduction in risk scoring.

The alternative mitigation plans examined in the SCE RAMP Report consisted of variations of the same categories listed above in Table Eleven with one exception. The exception is a proposed mitigation in the second alternative to accelerate hardware refresh for SCE employees. Rather than continuing the current four-year cycle for company hardware refresh, SCE would move to a one- to two-year cycle, prioritized by business area.

[21] ICS – Industrial Control System, SCADA – Supervisory Control and Data Aquisition

As noted in the SCE Report, due to security needs the details on mitigations must be limited in the RAMP process. As noted by SCE a secure process needs to be developed by the Commission so that specifics on tactics, techniques and procedures can be shared with appropriate parties. It is recommended that as an outcome of this RAMP proceeding, the Commission identify and incorporated such a process for future RAMP and GRC proceedings.

Within the context of California's utility safety framework, the Commission should also identify cybersecurity performance metrics as a means of tracking utility implementation of their mitigation plans. SCE's Report identified the US Department of Energy Electric Sector Cybersecurity Capability and Maturity Model (C2M2) and BitSight security ratings as tools it uses for measuring performance. In the upcoming GRC filing, SCE should provide information from these metrics for the past five years. If found to be valuable, these metrics should be reported on an annual basis.

iv. Physical Security

Table Thirteen: Physical Security Proposed Mitigation Plan Budget

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE
	Physical Security								
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$145	$1	2.10	0.114	8.25	0.057
C2	Protection of Generation Capabilities	2018	2023	$23	$1	1.66	0.71	6.53	0.28
C3b	Non-electric facilities/Protection of major business functions - enhanced	2018	2023	$74	$1	2.14	0.029	8.39	0.112
C4	Asset Protection	2018	2023	$10	$123	1.88	0.014	7.39	0.056
M1	Insider Threat Program Enhancement & Information Analysis - Bas	2019	2023	x	$1	1.17	0.795	4.75	3.227
M2	Smart Key Program Phase 1	2019	2022	$9	$0	1.65	0.178	6.55	0.707
	TOTAL			**$260**	$127	10.60	0.027	41.86	0.108

For the risk of physical security, providing for the physical safety of SCE's workforce, customers, facilities, assets and equipment is a critical part of its responsibility as a utility. For this risk, SCE is proposed a 2018-2023 budget of $260 million in capital investment, $127 million in operational expenses. The biggest proposed mitigation is for "Grid Infrastructure Protection", a continuation of a current mitigation. Two new mitigations are proposed, one to address insider threats and another for a smart key program. The smart key program is being adopted across the electric utility industry as a means to better track and control access to utility properties. In fact, two additional mitigations related to smart keys was included in an alternative mitigation plan. It is not clear why SCE did not include current compliance measures related to NERC CIP-014 and NERC V6 Low BES Sites. SCE also chose not to use an enhanced gird infrastructure protection mitigation.

In its RAMP Report, SCE notes in that its existing management systems do not entirely support how SCE modeled the physical security risk. SCE stated that it will consider modifying or augmenting the tracking and reporting capabilities of its current management systems. For the next GRC filing, SCE should provide a plan for accomplishing this modification in order to support future RAMP filings. This should be accompanied by a report on Physical Security performance metrics currently in use by SCE including performance data for the past five years. Additionally, a plan should be submitted that identifies location of physical security mitigations, budget and schedule, and justification.

V. Employee, Contractor and Public Safety

Table Fourteen: Employee and Contractor Safety Proposed Mitigation Plan Budget

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE
	Employee, Contractor, and Public Safety								
C1	Safety Controls	2018	2023	x	$14	0.43	0.03	0.33	0.024
C2	Contractor Safety Program	2018	2023	x	$1	0.42	0.384	0.33	0.3
M1	Safety Culture Transformation - Core Program	2018	2021	$13	$34	2.06	0.044	1.61	0.035
M2	Industrial Ergonomics	2018	2023	x	$0	0.07	0.769	0.05	0.6
M3	Office Ergonomics - Core Program	2018	2023	$14	$3	0.21	0.012	0.16	0.009
	TOTAL			**$27**	$52	3.18	0.04	2.48	0.031

This risk addresses occupational safety risks relevant to SCE employees and contractors and has no direct relationship with public safety. The Report does not specify whether this includes employees and contractors at the San Onofre Nuclear Generating Station (SONGS) but it is assumed that they are included in SCE's proposed mitigation plan.

CPUC does have regulatory oversight over IOU worker safety. While Cal/OSHA (Dept. of Industrial Relations) does have expansive jurisdiction over workplace safety (see, e.g., Cal. Lab. Code section 6309), this does not supersede the Commission's authority to enforce Public Utilities Code section 451, requiring that utilities "promote the safety, health, comfort and convenience of its patrons, employees and the public."

The CPUC routinely investigates occupational safety incidents, including IOU workplace injuries, that meet the Commission's reporting requirements. (See Pub. Util. Code section 315.) Pursuant to CPUC Decision 06-04-055, Appx. B, electric utilities must report incidents that result in:

- Fatality or personal injury rising to the level of in-patient hospitalization;
- Are the subject of significant public attention or media coverage; or,
- Damage to property of the utility or others estimated to exceed $50,000 and are attributable or allegedly attributable to utility owned facilities.

This Decision notes that:

Both the Commission and the California courts have repeatedly reaffirmed the Commission's exclusive jurisdiction over public utility facilities and operations. '[S]uch matters as the location of lines, their electrical and structural adequacy, their safety, and their meeting of the needs of the public within this state are clearly, by law, subject to the jurisdiction of this Commission.' (55 CPUC2d at 95, citing *Duncan v. PG&E* (1965) 61 PUR3d 388, 394.) Even in the absence of specific utility incident reporting requirements for vegetation-related incidents, the

Commission retains plenary authority to investigate any utility accident that poses a risk to public safety and system reliability.

Given the recent safety events at San Onofre, SCE must put forth a concerted effort to demonstrate that it is sufficiently addressing employee and contractor safety.

For this risk, SCE has a proposed budget of $27 million in capital investment, $52 million in operational expense for the years 2018 to 2023. A significant piece of this mitigation plan is a safety culture transformation program. Given that SB 901 specifies an independent safety culture evaluation for electric utilities, it may be appropriate for this mitigation measure to be deferred until the results of this independent evaluation is available. Other mitigations include ergonomics and a contractor safety program. Given the recent findings of the Nuclear Regulatory Commission on the lack of adequate project and contractor management, in its upcoming GRC filing SCE should include a specific contractor safety plan that includes all activities related to SONGS.

vi. Seismic Risk to Utility Assets

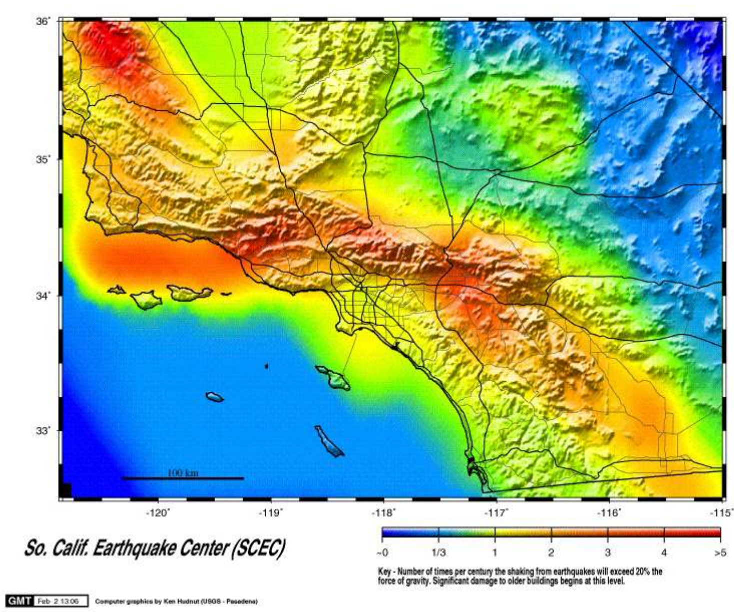


Figure 30: Caltech Seismic Risk Map for Southern California

According to the California Institution of Technology (Caltech), southern California should experience a magnitude 7.0 or greater earthquake about seven times each century. About half of these will be on the San Andreas "system" (the San Andreas, San Jacinto, Imperial, and Elsinore Faults) and half will be on other faults. The equivalent probability in the next 30 years is 85%. For this reason, SCE assets, generation, transmission and distribution, should be assessed for seismic safety and those assets found to be most vulnerable should be hardened to withstand a major event.

Some of this risk is captured under what SCE defines as "Building Safety." However, Edison's seismic risk is more significant in terms of its infrastructure and equipment with significant potential impacts than those related to a building's structural seismic risk, particularly if built to California's seismic and building codes.

For this reason, in its upcoming filing SCE should submit a proposed seismic assessment and accompanying proposed mitigation plan for infrastructure in high risk areas as designated on the Southern California Earthquake Center risk map.

C. Federally Regulated Asset Safety

Table Fifteen: SCE Proposed Hydro Asset Safety Expenditures

i. Hydro Asset Safety

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE
	Hydro Asset Safety								
C1	Seismic Retr	2018	2023	$7	x	0.02	0.0021	0.0496	0.0067
C2	Dam Surface	2018	2023	$1	x	0.00	0.0004	0.0007	0.0013
C3	Spillway Ren	2018	2022	$12	x	0.42	0.0353	1.3884	0.1157
C4	Low Level Ou	2018	2023	$13	x	0.02	0.0011	0.0492	0.0037
C5	Seepage Mit	2019	2022	$11	x	0.04	0.0034	0.1173	0.0112
C6	Instrumentat	2018	2021	$6	x	0.60	0.0937	1.8679	0.29.9
	TOTAL			**$50**	x	1.09	0.0217	3.4752	0.0692

SCE's hydro assets are regulated by the Federal Energy Regulatory Commission (FERC) and all assets are currently regulated under active FERC licenses. In addition, all capital expenditures are funded via FERC rate setting proceedings and are outside the scope of the Commission's Safety Policy and PUC regulations. Given that SCE has 22 FERC-licensed hydro projects with 16 projects needing relicensing in the next five years, it does raise concerns of what SCE expects in terms of future hydro operations, funding requirements and mitigation investments. SCE speculates in this Report that three projects may not be economically viable after relicensing and SCE will need capital investment funding for demolition of those projects. Given such uncertainties in terms of future hydro assets and operations, it is difficult for the Commission to come to any conclusion on the proposed mitigation plan. Unless the capital investments are solely for the six hydro projects that are not facing FERC relicensing, then it is may be soon to determine whether that proposed mitigation is a worthy investment.

Table Sixteen: SCE Hydro Assets

Dam Number	Dam Name	National ID No.	Latitude	Longitude	Owner Name	Owner Type	Dam Height	Crest Length	Reservoir Capacity	Dam Type	Certified Status	Downstream Hazard	Conditions Assessment	Reservoir Restriction	County	Year Built
104.018	CA00437	37.15	-119.3		SCE	IOU	2169	180	135283	GRAV	Certified	Extremely High	Satifactory	No	Fresno	1927
104.025	Mammoth Pool	CA00443	37.32	-119.32	SCE	IOU	820	406	123000	ERTH	Certified	Extremely High	Satifactory	No	Fresno	1960
104.010	Huntington Lake 1	CA00434	37.23	-119.24	SCE	IOU	1310	170	88834	GRAV	Certified	Extremely High	Satifactory	No	Fresno	1917
104.022	Big Creek No. 7	CA0440	37.21	-119.45	SCE	IOU	893	233	35000	GRAV	Certified	High	Satifactory	No	Fresno	1951
104.037	Gem Lake	CA00453	37.75	-119.14	SCE	IOU	688	75	17228	MULA	Certified	High	Fair	Yes	Mono	1917
104.030	Hillside	CA00446	37.17	-118.57	SCE	IOU	1555	81	12883	ROCK	Certified	High	Satifactory	No	Inyo	1910
104.039	Saddlebag	CA00455	37.97	-119.27	SCE	IOU	590	33	9765	ROCK	Certified	High	Satifactory	No	Mono	1921
104.032	Sabrina	CA00448	37.21	-118.61	SCE	IOU	900	70	8376	ROCK	Certified	High	Satifactory	No	Inyo	1908
104.034	Rush Creek Meadows	CA00450	37.75	-119.18	SCE	IOU	463	50	5277	CORA	Certified	High	Fair	Yes	Mono	1925
104.035	Lundy Lake	CA00451	38.03	-119.33	SCE	IOU	690	45	4113	ERRK	Certified	High	Satifactory	No	Mono	1911
104.042	Balsam Meadow	CA01283	37.16	-119.25	SCE	IOU	1325	127	2040	ROCK	Certified	High	Satifactory	No	Fresno	1986
104.027	Thompson	CA00445	33.36	-118.44	SCE	IOU	445	114	1010	ERTH	Certified	Significant	Satifactory		Los Angeles	1925
104.006	Big Creek No. 6	CA00432	37.21	-119.33	SCE	IOU	485	140	993	CORA	Certified	Low	Satifactory	No	Fresno	1923
104.038	Agnew Lake	CA00454	37.76	-119.13	SCE	IOU	278	20	810	MULA	Certified	High	Poor	Yes	Mono	1916
104.041	Rhinedollar	CA00457	37.93	-119.23	SCE	IOU	430	17	490	ROCK	Certified	High	Satifactory	No	Mono	1927
104.011	Lady Franklin Lake	CA00435	36.42	-118.56	SCE	IOU	400	21	467	GRAV	Certified	Low	Satifactory	No	Tulare	1905
104.024	Portal Powerhouse Forebay	CA00442	37.32	-119.07	SCE	IOU	792	65	325	ERTH	Certified	Low	Satifactory	No	Fresno	1955
104.02	Upper Monarch Lake	CA00439	36.45	-118.56	SCE	IOU	263	22	314	GRAV	Certified	High	Satifactory	No	Tulare	1905
104.031	Longley	CA00447	37.28	-118.66	SCE	IOU	120	27	178	ROCK	Certified	Low	Satifactory	No	Inyo	1910
104.019	Crystal Lake	CA00438	36.44	-118.56	SCE	IOU	94	17	162	GRAV	Certified	Low	Satifactory	No	Tulare	1903
104.002	Diversion No. 1	CA00429	35.53	-118.68	SCE	IOU	204	38	150	GRAV	Certified	High	Satifactory		Kern	1906
104.000	Bear Creek Diversion	CA00428	37.34	-118.98	SCE	IOU	241	55	103	CORA	Certified	Low	Satifactory	No	Fresno	1927
104.004	Big Creek No. 4	CA00430	37.2	-199.24	SCE	IOU	220	75	100	CORA	Certified	Low	Satifactory	No	Fresno	1913
104.033	Bishop Creek Intake No. 2	CA00449	37.25	-118.58	SCE	IOU	443	34	78	ERTH	Certified	High	Satifactory	No	Inyo	1908
104.026	Wrigley Reservoir (Catalina?)	CA00444	33.35	-118.35	SCE	IOU	190	42	62	ERTH	Certified	Significant	Satifactory	No	Los Angeles	1930
104.012	Mono Creek Diversion	CA00436	37.36	-119.00	SCE	IOU	112	50	45	CORA	Certified	Low	Satifactory	No	Fresno	1927
104.005	Big Creek No. 5	CA00437	37.2	-119.31	SCE	IOU	153	58	42	CORA	Certified	High	Satifactory	No	Fresno	1921

In this Report SCE proposes $50 million in capital expenditures for hydro assets through 2023. Given recent safety issues in the California hydro industry, it is recommended that the last mitigation, C6, instrumentation/communication enhancements be considered for expansion to better enable accurate risk assessments and performance metrics. This will better enable SCE and the Commission to track hydro assets with potential collateral benefits of improved wildfire, physical security, and emergency response risk management.

ii. Nuclear Decommissioning, Storage and Transportation Safety

The San Onofre Nuclear Generating Station is currently undergoing decommissioning with onsite storage of its legacy spent fuel. This activity is regulated under a Nuclear Regulatory Commission which has sole authority regarding nuclear safety and management. The Commission does oversee funding authority for this activity and it is under the Commission's Safety Policy and SB 901 utility safety framework that the Commission has the responsibility to ensure that SCE meets all safety and resilience performance expectations for this ongoing utility activity.

Currently, SCE is restricted from loading any spent fuel into its storage facilities due to serious violations in 2018. As described in the NRC's Inspection Report, it found cause to charge SCE with two violations of Federal law with a $116,000 fine. To date, NRC has not stated when it will allow for loading to resume.

Though not discussed in this Report, SCE has worked with the NRC to take corrective actions. In its upcoming filing, SCE should provide documentation of recent safety mitigation measures, its contractor's Root Cause Evaluation of the 2018 incidents, the SCE Apparent Cause Evaluation, and proposed future measures including contractor training.

d. Building Safety

Table Seventeen: SCE Proposed Building Safety Expenditures

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Mean Value (MARS)		Tail Average (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE
	Building Safety								
C1	Seismic Building Safety Program	2018	2023	$42	$6	0.73	0.015	2.56	0.053
C2	Facility Emergency Management Program	2018	2023	x	$1	0.19	0.226	0.65	0.794
M1	Fire Life Safety Portfolio Assessment	2018	2023	$5	$1	0.00	0.0001	0.003	0.0005
M2	Electrical Inspections	2018	2023	$5	$10	0.87	0.06	2.57	0.177
	TOTAL			**$52**	$17	1.79	0.026	5.78	0.083

In aggregating multiple lower-consequence risks in Building Safety, SCE addresses risks associated with seismic risk in utility buildings, electric fires due to faulty wiring and potential damage due to foreign object such as wind-blown debris hitting the side of a building. In fact, the proposed plan dedicates over 80% of proposed budget to seismic risk. As discussed earlier, this risk should be replaced with a new proposed risk, seismic risk to generation, distribution and transmission assets.

e. Climate Resilience

Table Eighteen: SCE Proposed Climate Resilience Mitigation Expenditures

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
	Climate Change	Start Year	End Year	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.24	0.1	7.46	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.02	0.22	0.99	0.42
M1	Climage Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.81	0.33	2.65	1.08
M2a	Situational Awareness, Monitoring & Analytics	2018	2023	$26.8	$28.0	2.25	0.04	6.08	0.11
				$26.8	$56.4	6.32	0.08	18.18	0.22

In April 2015, then Governor Brown signed Executive Order B-30-15 calling for adaptation implementation plans for each sector of the economy as the State was already facing the impacts of climate change from increased heat waves, droughts and wildfires. The executive order was part of a larger state-level effort on adaptation to climate change called Safeguarding California[1], begun in 2009. Concurrently, the three large California IOUs were working with the US Department of Energy (DOE) through DOE's Partnership for Energy Sector Climate Resilience (Partnership)[2]. This Partnership consists of the Federal government and 18 electric utilities from around the country seeking to enhance US energy security by improving the resilience of energy infrastructure to extreme weather and climate change impacts. A key aspect of this Partnership is the development of vulnerability assessments to determine where grid infrastructure might be vulnerable to climate change impacts, and climate resilience plans to address these potential vulnerabilities over the long term.

Per its Memorandum of Understanding agreement with the Partnership, SCE prepared their report *Climate Impact Analysis and Resilience Planning* in November 2016. This document was aided by the development of an Adaptation Planning Tool that allows SCE to analyze the impacts that long-term climate change would have through its service territory down to the local level. However, that information is not included in the resilience report attached to the RAMP report. Their climate report did include a summary of mitigation strategies outlined in the course of internal subject matter expert workshops. Those strategies ranged from conducting additional research such as site-specific engineering reviews, and purchase of additional equipment to reduce increased system stress, to adding additional reservoir locations and capacity, and finally relocating facilities located in the 100-year flood plain areas. However, the plan provides only a few examples of adaptation measures and does not delve into how the measures listed would be compared against other options.

It is also not clear how these and other strategies outlined in the vulnerability assessment and resilience plans contributed to the development of the mitigation plan in the 2018 RAMP report. Many of the resilience options are long-term strategies that are outside of the RAMP reporting period of 2018-2023.

DOE issued specific guidance regarding the information that should be included in the vulnerability assessments. They called for the identification of the magnitude and probability of climate impacts to their key assets. In January 2016, the Policy and Planning Division of the CPUC issued a paper entitled *Climate Adaptation in the Electric Sector: Vulnerability Assessments and Resilience Plans*[3] that recommended that the IOUs conduct assessments consistent with DOE guidance as well as add several additional areas of analysis such as regional vulnerabilities and impacts to specific vulnerable and disadvantaged communities. The attached workpaper from SCE does not follow either the DOE guidance or the CPUC guidance.

The SCE RAMP Report acknowledges the challenge of addressing a long term (i.e. 30 to 50 year) challenge such as climate change with the shorter term (5 year) perspective of the GRC process. However, the RAMP Report does not address the intermediate actions that need to be addressed in the 2018 to 2023 timeframe that would lead to additional actions and options in the future. Further, the proposed climate resilience mitigations in the RAMP tend to be duplicative of mitigation measures proposed under other risks.

In May 2018, the Commission issued an Order Instituting Rulemaking (OIR) (R.18-04-019) to consider strategies to integrate climate change adaptation planning in relevant Commission proceedings and other activities. The Rulemaking was divided into two phases, with the first phase covering the electric and natural gas utilities only. However, the Commission noted that water and telecommunications utilities may be covered under the Phase 2 proceeding. The Scoping Memo was issued on October 10, 2018 and stated:

"The main purpose of this OIR is to provide guidance to utilities on how to incorporate climate adaptation into their planning and operations…Phase 1 of this Rulemaking will broadly consider how best to integrate climate change adaptation into the larger investor-owned electric and gas utilities' planning and operations to ensure safety and reliability of utility service. This phase will focus on addressing five key topics, described below:

1. Definition of climate adaptation for utilities;
2. Appropriate data sources, models, and tools for climate adaptation decision-making;
3. Guidelines for utility climate adaptation assessment and planning;
4. Identification and prioritization of actions to address the climate change related needs of vulnerable and disadvantaged communities; and
5. Framework for climate-related decision-making and accountability."

This proceeding will serve as a venue to support the IOU efforts to address the long-term perspective of adapting to climate change. Climate resilience has its own unique characteristics that warrant this separate OIR and should be evaluated separate from Tier 1 through 3 risks. Climate resilience efforts need to look more long-term than RAMP risk assessments and therefore strategies to address climate resilience will have longer lifecycles and does not fit within the RAMP process which focuses on short-terms risks and mitigations. Presumably, this separate review of climate resilience with be one of the outcomes of the current OIR.

Based on the direction provided by the assigned Commissioner's office (Commissioner Randolph) in the Scoping Memo, as well as staff proposals and stakeholder feedback, there is a considerable amount of pressure on the IOUs to increase their efforts on adaption to climate change. Therefore, it is our recommendation that the IOUs not wait for the final decision from the Commission, but rather begin to address the risk posed to the utility operations and their customers immediately. We would recommend the following actions be taken as soon as possible:

1. Conduct thorough vulnerability assessments per the direction of the DOE guidance and the CPUC guidance to fully understand the impacts that climate change will have on the grid and the customers.
2. Prepare resilience plans that address those vulnerabilities providing several options and an analysis of the costs and long-term benefits of those actions.
3. Provide 3-5 year investment plans based on the resilience plans to begin investing in long term adaptation to the anticipated impacts of climate change.

[1] http://resources.ca.gov/climate/safeguarding/

[2] https://www.energy.gov/policy/initiatives/partnership-energy-sector-climate-resilience

[3] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD%20-%20Climate%20Adaptation%20Plans.pdf

7 CONCLUSION AND RECOMMENDATIONS

a. CONCLUSION

The SCE RAMP Report met Commission requirements as of November 2018. With new laws and policies to address California's wildfire risk, this staff review of the submitted material (Review) examines how SCE 1) demonstrates safety and resilience leadership, 2) identifies and ranks its risks, and 3) plans for improvements to address their most significant utility safety risks.

In previous RAMP proceedings, staff reviews were necessarily limited to what had been developed up to that point in terms of probabilistic risk modeling. In its RAMP Report, 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 is in step with the progress made in the SMAP proceeding and reflected in the resulting settlement agreement and Commission Decision. This milestone establishes a risk modeling standard for RAMP proceedings and allows for staff reviews to fulfill their original intent, to inform and advise the Commission on General Rate Case (GRC) proceedings. This Review is the first to take the utility information and begin to establish how to use it in a risk-informed decision-making framework. Therefore, this review begins with an acknowledgment of recent State regulatory reforms that specifically target utility safety management. SB 901 and Executive Order N-05-19 set the State's priorities for wildfire safety in 2019 and are integrated into this review. The Review then reviews SCE's recent safety history, how the utility identified its most significant utility safety risks associated with their electric assets. The Review then ranks these risks and adds additional utility safety risks that were omitted by the utility. Finally, individual proposed mitigation plans are critiqued and recommendations made for the associated upcoming GRC filing.

In its' Report, SCE provides a safety performance metric as an illustration that it has made improvements in occupational safety performance over recent years. A review of SCE's safety efforts over the past ten years and its fines by the Commission over this same period indicate not all aspects of safety have been adequately addressed.

Based on the State's utility safety policies and the information provided in SCE's Report, the Commission should consider the major utility safety risks in SCE's service territory to be wildfire and flooding/mudslides. Other operational risks are important to review as part of the upcoming General Rate Case (GRC) but emphasis must be put on reducing catastrophic risk through the GRC period that spans through 2023. This Review also establishes a framework so that all major risks are addressed and included in both the RAMP and GRC and other safety proceedings.

When the RAMP proceeding process was first established, it sought to include the impacts of climate change without having a clear sense of how to accomplish this goal. The recent RAMP proceedings have demonstrated that this subject is worthy of its own separate, comprehensive review which is not possible within the current RAMP review cycle. The Commission has acknowledged this with the initiation of an OIR on climate adaptation. In a 2018 letter to the Federal Energy Regulatory Commission, the Commission asserted that

> In assessing whether a project is in the public interest, FERC can consider the most accurate estimates of . . . best practices, relevant climate goals for the region, and specific climate impacts . . .[22]

A separate climate resilience review would fulfill a current need for exactly what the Commission specifies in its letter to FERC. With the State's recent publication of its 4th Climate Change Assessment, California utilities should follow best-in-industry practices such as using this Climate Assessment to forecast future climate change impacts and what will constitute a climate resilient utility in future decades. This long-term perspective is currently lacking and would greatly inform all stakeholders in future RAMP and GRC proceedings.

b. General Recommendations

Specific recommendations related to SCE's mitigation plans are included in those review chapters. There are also general recommendations regarding expectations the Commission and stakeholders should have for the upcoming for the SCE GRC filing considering recent reforms and activities. Recommendations related to additional technical analyses that should be conducted for Wildfire and Contact with Energized Equipment risks are also included in Appendix C.

As we move forward in this new era of utility safety, the Commission will need to adapt its processes, proceedings, decisions, and regulations to meet the challenges of this era. Therefore, this Review concludes with two recommendations for SCE's upcoming GRC filing to meet the letter and spirit of California's new utility safety framework

1. Shared Stewardship Program

In 2018 the U.S. Department of Agriculture (USDA) Forest Service (USFS) initiated a new strategy for addressing catastrophic wildfires and the impacts of drought and poor forest health. Described as an outcome-based investment strategy[23], the USFS "Shared Stewardship"

[22] Rechtschaffen, Clifford, Commissioner Blog: CPUC Tells FERC Climate Change Must be Considered in Infrastructure Projects, July 26, 2018

[23] US Forest Service, Toward Shared Stewardship across Landscapes: An Outcome-based Investment Strategy, FS-118, August 2018

strategy defines the USFS's plans to work more closely with states to identify landscape-scale priorities for targeted treatment in areas with the most benefits.

Building upon its new authorities created by the 2018 Omnibus Bill, the USFS specifically notes that the challenges before all stakeholders require a new approach. A key component of the new strategy is to prioritize investment decisions on forest treatments in direct coordination with states using the most advanced science tools. In the end, the goal is to increase the scope and scale of critical forest treatments that protect communities and create resilient forests and utilities.

There are many similarities between the USFS Shared Stewardship Program and the Commission's RAMP efforts. What is needed is better coordination with stakeholders and agencies, including USFS, on their wildfire prevention as they relate to utility assets, operations, and mitigation activities.

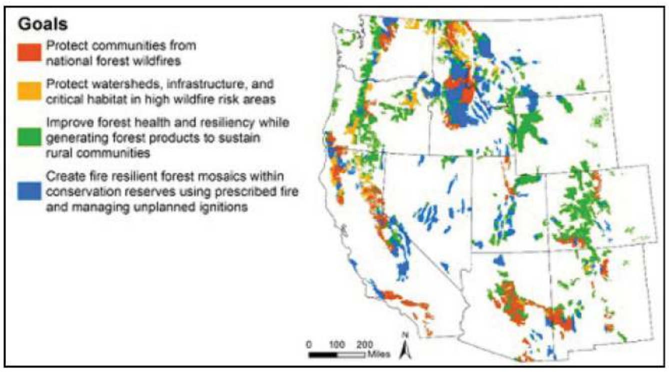


Figure 9. Conceptual map of "investment themes" derived from scenario planning showing broad potential goals. The goals are not mutually exclusive; often, several goals can be met on the same landscape.

Figure 32: USFS conceptual map of "investment themes" derived from scenario planning showing broad potential goals.

In the upcoming GRC filing, SCE should submit a Shared Strategy Plan (SSP) that includes the identification of current activities by all key wildfire agencies within the high fire threat areas of their service territory. In the Plan, SCE should assess whether these agency projects have impacts on utility assets, operations, or mitigations. These should include CalFire mitigation projects[24], described in their recent 45 Report[25], CalFire Fire Prevention grants, utility wildfire community grants, FEMA-funded, and locally funded projects. SCE will report to the Commission whether there are any duplicative projects or opportunities for improving performance and outcomes through partnerships that enable better design, coordination, and execution of mitigation projects.

2. Vulnerable Communities Program

[24] See CAL FIRE Priority Fuel Reduction Project List

[25] CAL FIRE, Community Wildfire Prevention & Mitigation Report, February 2019

In the Community Wildfire Prevention & Mitigation Report prepared by Cal Fire in cooperation with multiple State agencies including the Commission, it noted that certain populations in California are particularly vulnerable to wildfire risks. These communities face higher public safety threats than other areas of the State and as this report acknowledges that there is a need for urgent action, which is the purpose of Executive Order N-05-19. With this new State wildfire policy, the emphasis is on protecting vulnerable populations, using a strategic approach where necessary actions are

> focused on California's most vulnerable communities as a prescriptive and deliberative endeavor to realize the greatest returns on reducing risk to life and property[26].

In the upcoming GRC filing, SCE should submit a Vulnerable Communities Program (VCP) plan (Plan) that is consistent with State wildfire policies and describes an ongoing utility program that includes

- Assessment of High Fire Threat Areas in Service Territory
- Assessment of Strategic LTE Network, covered conductor, and Undergrounding Opportunities
- Regional Fire Potential Indices Program
- Community Resource Centers in Vulnerable Communities
- Report on 2018 De-energization Program
- De-energization Protocols for 2019
- Flooding/Mudflow Impact Assessments
- Restoration and Recovery Plans
- Community Grants, Outreach and Public Engagement Plans

Most of the above items are currently required under SB 901 and EO-N-05-19. This Vulnerable Communities Program provides a framework for how the required proposed budget and risk assessment should be considered in the upcoming GRC proceeding.

In conclusion, State laws, policies, and regulations related to utility safety have significantly shifted in 2019 and this Review reflects those changes to policy goals, programs, and funding. The Review includes a more inclusive examination of utility safety management and recent history. The utility safety risks that SCE identified as most significant to their utility safety was ranked and then individual mitigation plans presented in the RAMP report was assessed. Finally, recommendations are made for what content SCE should include in its upcoming GRC filing that supports the State's utility safety goals, objectives and policies.

[26] Ibid

APPENDIX A SCE PROPOSED RAMP MITIGATION BUDGETS

ID	Name	Implementation Period		Cost Estimates ($M)		Expected Value (MARS)	
		Start Year	End Year	Capital	O&M	MRR	RSE
	Contact W Energized Equipment (Amendment)						
C1	Overhead Conductor Program (DCP)	2018	2023	$715	x	3.22	0.0045
C1a	Overhead Conductor Program (DCP) Utilizing Targeted Covered Conductor	2021	2023	$34	x	0.10	0.0029
C2	Public Outreach	2018	2023	x	$33	0.42	0.013
M4	Infrared Inspection	2018	2023	x	$3	1.04	0.3627
M5	Wildfire Covered Conductor Program	2018	2023	$1,161	x	0.54	0.0005
	TOTAL			**$1,910**	$36	5.32	0.0027
	Wildfire (Amendment)						
C1	Overhead Conductor Program (Bare & Covered)	2018	2023	$102	x	0.09	0.0009
C2	FR Overhead Distribution Transformer	2018	2023	$81	x	0.06	0.0007
M1	Wildfire Covered Conductor Program	2018	2023	$1,161	x	1.64	0.0014
M2	Remote-controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$28	$3	0.97	0.0311
M3	PSPS Protocol and Support Functions	2018	2023	x	$21	1.90	0.0892
M4	Infrared Inspection Program	2018	2023	x	$3	0.29	0.1029
M5	Expanded Vegetation Management	2018	2023	x	$370	0.38	0.001
M7	Enhanced Situational Awareness	2018	2023	$31	$26	0.84	0.0149
M8	Fusing Mitigation	2018	2020	$68	$23	0.23	0.0025
M9	Fire Resistant Poles (M1 Scope)	2018	2023	$137	x	0.60	0.0044
				$1,609	$447	7.02	0.0034
	Underground Equipment Failure						
C1	Cable Replacememt programs (WCR)	2108	2023	$601	x	0.44	0.0007
C2	Cable Replacement Programs (CIC)	2108	2023	$368	x	2.22	0.006
C3	UG Oil Switch Replacement Program	2108	2023	$110	x	0.16	0.0014
M1	Cover Pressure Relief and Restraint (CPRR) Program	2019	2023	$68	x	0.86	0.0126
	TOTAL			**$1,147**	x	3.67	0.0032
	Cyberattack						
C1a	Perimeter Defense	2018	2023	$81	$35	1.51	0.013
C2a	Interior Defense	2018	2023	$48	$24	0.91	0.013
C3a	Data Protection	2018	2023	$31	$17	0.02	0
C4a	SCADA Cybersecurity	2018	2023	$20	$20	0.46	0.012
C5a	Grid Modernization Cybersecurity	2018	2023	$169	$34	1.41	0.007
	TOTAL			**$348**	$129	4.31	0.009
	Physical Security						
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$145	$1	2.10	0.114
C2	Protection of Generation Capabilities	2018	2023	$23	$1	1.66	0.71
C3b	Non-electric facilities/Protection of major business functions - enhanced	2018	2023	$74	$1	2.14	0.029
C4	Asset Protection	2018	2023	$10	$123	1.88	0.014
M1a	Insider Threat Program Enhancement & Information Analysis - Bas	2019	2023	x	$1	1.17	0.795
M2	Smart Key Program Phase 1	2019	2022	$9	$0	1.65	0.178
	TOTAL			**$260**	$127	10.60	0.027
	Building Safety						
C1	Seismic Building Safety Program	2018	2023	$42	$6	0.73	0.015
C2	Facility Emergency Management Program	2018	2023	x	$1	0.19	0.226
M1	Fire Life Safety Portfolio Assessment	2018	2023	$5	$1	0.00	0.0001
M2	Electrical Inspections	2018	2023	$5	$10	0.87	0.06
	TOTAL			**$52**	$17	1.79	0.026
	Hydro Asset Safety						
C1	Seismic Retrofit	2018	2023	$7	x	0.02	0.0021
C2	Dam Surface Protection	2018	2023	$1	x	0.00	0.0004
C3	Spillway Remediation and Improvement	2018	2022	$12	x	0.42	0.0353
C4	Low Level Outlet Improvements	2018	2023	$13	x	0.02	0.0011
C5	Seepage Mitigation	2019	2022	$11	x	0.04	0.0034
C6	Instrumentation/Communication Enhancements	2018	2021	$6	x	0.60	0.0937
	TOTAL			**$50**	x	1.09	0.0217
	Employee, Contractor, and Public Safety						
C1	Safety Controls	2018	2023	x	$14	0.43	0.03
C2	Contractor Safety Program	2018	2023	x	$1	0.42	0.384
M1a	Safety Culture Transformation - Core Program	2018	2021	$13	$34	2.06	0.044
M2	Industrial Ergonomics	2018	2023	x	$0	0.07	0.769
M3a	Office Ergonomics - Core Program	2018	2023	$14	$3	0.21	0.012
	TOTAL			**$27**	$52	3.18	0.04
	TOTAL RAMP			**$5,404**	$808		

APPENDIX B CPUC SAFETY POLICY STATEMENT

California Public Utilities Commission

Safety Policy Statement of the California Public Utilities Commission

Purpose of this Policy

This is the Safety Policy adopted by the Commissioners of the California Public Utilities Commission (CPUC). It defines the role of the Commissioners, binds together the agency in constantly strengthening our safety efforts, and provides a unifying vision and guidance for the organization's multiple and disparate functions.

As described below, as a first step in applying this policy, we also will direct our staff to provide to the CPUC a more detailed Safety Plan within 180 days, laying out specific elements and staff actions on how the entire organization - including the five Commissioners and their staff, our legal and judicial staff, our policy and program staff, as well as our administrative staff - will respond to this policy in all their work.

CPUC Overarching Safety Mission

The safety mission and goal of the CPUC is to assure to the State of California that all of us will work every day to assure that the regulated utilities we depend on for critical services are as safe and resilient as they can possibly be.[1] The CPUC not only will assure compliance with safety laws and regulations, but also challenge itself and the utilities to excellence.

Ultimately we are striving to achieve a goal of zero accidents and injuries across all the utilities and businesses we regulate, and within our own workplace.[2]

We have a broad obligation in this mission, and we must assure that safety will always be an important component in all that we do and everywhere we have authority and responsibility. Our efforts must improve protection for the public, for utility workers and CPUC employees in their work, for the environment, and for utility infrastructure and systems.

To realize this Vision, the CPUC commits to these guiding principles:

- Continually assess and reduce the safety risk posed by the companies we regulate
- Hold companies (and their extended contractors) accountable for safety of their facilities and practices
- Be accountable for the oversight of safety in the industries we regulate
- Provide clear guidance on expectations for safety management and outcomes
- Provide transparent and effective procedures for enforcement of those expectations
- Promote reliable access to utility services that support health and safety
- Promote a culture of safety vigilance by CPUC staff, and in the industries we regulate
- Learn from experience and continuously improve safety oversight and outcomes

---

[1] The CPUC's overall mission is to protect consumers and ensure the provision of safe, reliable utility service and infrastructure at reasonable rates, with a commitment to environmental enhancement and a healthy economy.

[2] The concept of zero accidents and injuries is based on the Vision Zero Initiative established in Sweden in the 1990s. It began as an approach to roadway safety, and can be summarized as a single sentence: "No loss of life is acceptable." Since 1997, England and the Netherlands have adopted this policy goal, and in 2014, the cities of New York, Boston, and San Francisco also adopted it as their road safety policy expectation. Similarly, the USDOT Pipeline and Hazardous Material Safety Administration states, "our vision is that no harm results from hazardous materials transportation."

1

July 10, 2014

Leadership on this mission begins at the highest levels of our organization. In this respect, Commissioners commit to do the following:

- Certify through signature on Scoping Memos that our proceedings cover key safety and resiliency questions that will be answered during the course of the proceeding.
- Certify through signature on Proposed Decisions that the findings, conclusions, and actions laid out in proceedings can meet the CPUC's overarching goals and expectations.
- Assure that each vote on proceedings, resolutions, ratemaking, or other decisions of the CPUC addresses the CPUC's overarching goals and expectations regarding safety and resiliency.
- Regularly monitor in public meetings progress made by CPUC staff and regulated utilities and businesses in performing key safety activities and their outcomes, as defined in a comprehensive safety management plan.
- Continue to ensure that the CPUC creates confidential programs that protect from reprisals whistleblowers in government and in regulated utilities who raise safety issues, and provide for timely follow up to verify the accuracy of their information.

Staff Directives

CPUC staff has key responsibilities to carry out the above policy. These include assuring effective compliance with safety requirements, proactively managing safety risks, and promoting excellent safety cultures within regulated utilities and businesses. As a first step, the Executive Director and Division Directors together will:

- Within 180 days, design an ongoing safety management system, and prepare a work plan with priorities and clear and measurable goals and objectives to demonstrate CPUC staff effectiveness toward our core goal.
- Develop a monitoring, reporting, and records tracking system that demonstrates the effectiveness of utility and regulated businesses' progress on actions taken to achieve a zero accidents goal.
- Develop a monitoring system within our own workplace to track staff activities on achieving a zero accidents goal.
- Provide CPUC staff with adequate tools and training to carry out their jobs of assuring that utilities meet our safety goals.
- Coordinate with other state and federal agencies to: address gaps in public safety authority within the CPUC's oversight; identify and detect risks; and, gain more effective compliance through improved coordination for enforcement of regulated utilities.
- Regularly demonstrate progress on these tasks in the CPUC's public meetings.

The utilities that adhere to our rules and regulations must ultimately implement this vision, and we expect that these entities will create a culture within their organizations that puts safety first in their actions. To this end, the CPUC will schedule annual en banc hearings where the Chief Executive Officer of each of the major utilities we regulate will present to the CPUC the current status of their respective safety programs.

This policy statement is a living document, subject to change over time. The CPUC will utilize it on an ongoing basis to offer guidance, direction, and focus on our safety oversight responsibilities.

Appendix C – SCE's Wildfire & Contact with Energized Equipment Risk Assessments, Analysis by Wendy Al-Mukdad, P.E. (CA E18855)

1 Analysis of SCE's Wildfire Risk Assessment

1.1 Pole Driver & Related Mitigation Programs

In the context of SCE's 2015 GRC and 2018 GRC, the high priority and high cost Pole Loading & Deterioration Pole Replacement Programs, that were put in place to minimize safety risks including wildfire risks, were not included in the Wildfire RAMP chapter. SCE also did not include pole drivers for Wildfire triggering events at all in its RAMP.

In response to SED's inquiry at the SCE RAMP Public Workshop[27] (12/14/2018) why pole drivers were not included in their wildfire risk assessment, SCE states: "The driver data evaluated in the Wildfire risk was based on D.14-02-015 reportable ignition events associated with distribution infrastructure within SCE's HFRA between 2015 and 2017. During this three-year period, and within SCE's HFRA, there were zero such ignition events attributed to pole failure. For this reason, the driver category D2 "Equipment/Facility Failure" did not include a sub-category for poles. At a higher level, there were three reported pole failure ignition events in the entire SCE system during the years 2015-2017. All three of these ignition events were associated with distribution infrastructure, but none of the three were located within SCE's HFRA."[28]

Additionally, SCE states: "Through the pole-related programs listed in the Contact with Energized Equipment chapter, SCE does take action to replace poles that present an increased probability of failure. SCE agrees that these programs also help control wildfire risk. The lack of identification of these activities in the Wildfire chapter narrative was an oversight on SCE's part. This oversight was related to the fact that historically, zero pole failure events occurred in the wildfire driver data (see response to SED-SCE-Verbal-001 Question 2). Because zero pole failure events were found in the driver data, SCE inadvertently omitted any discussion of pole-related compliance activities within the Wildfire chapter narrative."[29]

Since there were no pole failure ignition events on SCE's distribution infrastructure in these three years (2015-2017), SCE should do risk analysis on pole failure ignition events to inform the Commission how much continued investment in large scale pole replacement programs are projected to reduce pole failure ignition events, particularly to prevent catastrophic wildfires. This risk analysis should differentiate between benefits that SCE projects it has already obtained by past pole replacements, heavily focused in their defined HFTA, and benefits that SCE projects it would obtain by further deployment of these pole replacement programs.

Additionally, as shown and discussed further in Section 2.0, Analysis of Contact with Energized Equipment (CEE) Risk Assessment, section, SCE states that "[p]ole failures that lead to wire-down events typically occur when there is deterioration at the top of pole. Pole deterioration

---

[27] Video recording available at: https://centurylinkconferencing.webex.com/mw3300/mywebex/nbrshared.do
[28] SED-SCE-Verbal-001 Question 2 Data Request Response, 1/3/2019.
[29] SED-SCE-Verbal-001 Question 6 Data Request Response, 1/3/2019.

can take place at any location on a pole. Unless the deterioration is visible, SCE's intrusive pole inspection program and pole loading assessments cannot effectively test for, or detect, deterioration at the top of the pole." This fact makes it very difficult to understand how Pole Loading & Deterioration Replacement Programs will effectively mitigate pole failure ignition events. From this claim, it seems to reason that some type of pole top inspection would be more beneficial, if feasible, and proves to have a high risk spend efficiency. SCE should address this concern promptly in relevant proceedings.

SCE's Data Request Responses and statements further point to the lack of root cause analysis data to show the need for these programs from a risk reduction analysis. This was identified as a deficiency in the SED SCE Risk & Safety Aspects of 2018 GRC Report, Appendix A – Pole Loading Risk Assessment Methodologies Deficiencies, dated 1/31/2017. SCE also states "Please note that even if SCE had listed these activities in the narrative, SCE still would not have modeled these pole-related compliance activities in the RAMP analysis."[30] As discussed further in the Section 2.0, risk reduction analysis including Risk Spend Efficiency (RSE) calculations would be most appropriate for decision-makers to be able to assess programs based on SCE's internal standards based on safety risks and costs even for programs that SCE deems to be compliance programs. As SED opines in Section 2.0, SED disagrees with SCE's assumption that these programs are compliance programs. Even if they were compliance programs, risk reduction analysis and data could be very informative for decision-makers to determine the benefits and effectiveness of compliance programs.

Finally, it behooves SCE to include which triggering events these high cost pole replacement programs are mitigating and to do RSE calculations based on relevant triggering events based on actual historical event data. And similar to circuit (or line segment) risk spend efficiency analysis discussed more below, perhaps pole related programs could be analyzed pole by pole with RSE calculations per pole.

1.2 Circuit by Circuit Risk Analysis for WCCP using Index Score for RSEs

As discussed in Section 2.0, 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. More detailed risk spend efficiency (RSE) calculations by circuit or line segment could be valuable to determine where fault detection and/or system hardening measures provide the highest risk reduction benefits. Risk spend efficiency (RSE) calculations could be calculated by circuit or line segment since circuit prioritization has already been conducted by SCE for the WCCP proposed mitigation measure. RSE calculations by circuit or line segment could be conducted to provide decision makers a measure of how much risk would be reduced based on cost for each circuit or line segment. This could be done for the proposed WCCP mitigation measure and for other potential system hardening and other mitigation measure that could be deployed and/or implemented on that

[30] *Ibid*

circuit or line segment (e.g. undergrounding, automatic reclosers, other electric power protection engineering mitigation measures, etc.).

The idea of risk spend efficiency calculations by circuit or line segment is similar to the work by W. Kent Muhlbauer, internationally recognized authority on pipeline risk management. In his 2015 © Pipeline Risk Assessment: The Definitive Approach and Its Role in Risk Management, Muhlbauer describes an approach to comprehensive pipeline risk assessment based on utilities having unprecedented amounts of data available that was unavailable in past decades. As Muhlbauer states: "The best practice in risk assessment is to assess major risk variables by evaluating and combining many lesser variables, generally available from the operator's records or public domain databases. This is sometimes called a reductionist approach, reducing the problem to its subparts for examination. This allows assessments to benefit from direct use measurements or evaluations of multiple smaller variables, rather than a single, high-level variable, thereby reducing subjectivity. If the subparts—the details—are not available, then higher level inputs must suffice." (page I-3) Additionally, more information can be found at http://pipelinerisk.net/

Hence, SED believes that the Index Score calculated for the Wildfire Covered Conductor Program to prioritize circuits for implementation of deployments could be utilized in RSE calculations combined with average cost of covered conductor replacement per circuit or conductor mile. In the future, estimated project cost per circuit or line segment, rather than average program cost, would improve these risk spend efficiency calculations even more.

In SCE Data Request Response for TURN-SCE-005, dated 1/17/19, in SCE A.18-09-002, Grid Safety & Resiliency Program (GS&RP), SCE provides an "Excel file contain[ing] the working formulas, supporting information and calculations used in SCE's circuit-level prioritization for covered conductor deployment… this spreadsheet includes the detailed calculation of the "Index Score" for each circuit within SCE's HFRA." See Figure 1 for a snapshot of the first 23 ranked overhead circuits for fire threat characteristics shown with their Index Score.

Figure 1: Partial Snapshot of Top 9 Ranked Overhead Circuits for Fire Threat Characteristics

				Fire Threat (Frequency) Characteristics								
Rank	OH Circuit Name	Total Circuit Length (OH Primary) (Ckt Mi.)	Total HFRA Length - OH Primary (Ckt Mi.)	Length (Ckt Mi.) Within Tier 3 - OH Primary	Length (Ckt Mi.) Within Tier 2 - OH Primary	High Wind in HFRA Length (Ckt Miles) - OH Primary	Historical Wiredown Count (May 2014 - 2017)	Small Conductor (Ckt Miles)	Mitigated HFRA Fault / Total Ckt Length	HFRA Vegetation Fault Count	Index Score	Potentially Mitigated HFRA Faults (2015-2017)
1	THACHER	83.55	83.56	83.53	0.03	67.77	2	36.58	0.12	8	39.51	10
2	METTLER	130.09	130.09	129.45	0.64	111.59	2	45.80	0.12	0	36.93	16
3	CUDDEBACK	89.07	89.42	87.77	1.65	60.59	2	29.46	0.09	5	34.09	8
4	JORDAN	164.04	164.04	0.00	164.04	63.33	2	151.23	0.04	3	32.47	6
5	HUGHES LAKE	102.19	89.59	67.84	21.51	80.37	2	56.25	0.06	2	28.76	6
6	CHAWA	98.99	98.99	97.56	1.43	87.01	1	44.91	0.02	0	27.91	2
7	GALAHAD	57.33	57.36	57.05	0.31	57.36	5	32.92	0.09	3	27.50	5
8	TITAN	118.74	103.15	46.45	27.17	102.83	3	81.72	0.03	1	26.86	4
9	TENNECO	100.36	100.36	47.08	51.09	57.74	1	55.00	0.11	3	26.53	11

In Figure 1, the partial snapshot of SCE's Fire Threat (Frequency) Characteristics spreadsheet above, SCE has already gathered data on all the circuits in their High Fire Threat Area in order to calculate Index Scores and Rank the circuits including:

- Overhead (OH) Circuit Name
- Total Circuit Length (OH Primary) (Ckt. Mi.)
- Total HFRA Length – OH Primary (Ckt. Mi.)
- Length (Ckt. Mi.) Within Tier 3 – OH Primary
- Length (Ckt. Mi.) Within Tier 2 – OH Primary
- High Wind in HFRA Length (Ckt Miles) OH Primary
- Historical Wiredown Count (May 2014 -2017)
- Small Conductor (Ckt Miles)
- Mitigated HFRA Faults / Total Ckt Length
- HFRA Vegetation Fault Count
- Potentially Mitigated HFRA Faults (2015-2017)

SCE also has additional data for these circuits that is not shown in the snapshot including Voltage, Region, and District.

SCE also explained the following in SCE's same TURN Data Request Response:

The data in th[e] column [labeled] ("Potentially Mitigated HFRA Fault / Total Ckt Length (OH Pri – Ckt Mi.)" was based on 2015-2017 historical outage data extracted from SCE's Outage Database and Reliability Metrics (ODRM) system, filtered for outage cause codes identified as being potentially mitigated through deployment of covered conductor. Because ODRM does not explicitly identify "fault location", geospatial analysis was used to identify the closest known SCE structure to the location information provided in ODRM. If this closest known structure was within SCE's HFRA, then the associated fault was assumed to also be in SCE's HFRA. The total count of these faults was then divided by the total circuit length to normalize the data. For example, on the Thacher 16 kV circuit, a total of 10 faults in 2015-2017 were identified to be within SCE's HFRA and potentially have been mitigated by application of covered conductor for the 83.5-mile circuit. This resulted in a calculated value of 10/83.5 = 0.12 mitigated faults per circuit mile for Thacher 16 kV.

The data in the column [labeled] "HFRA Vegetation Fault Count" is based on 2015-2017 historical outage data extracted from SCE's Outage Database and Reliability Metrics (ODRM) system, filtered for outage cause codes associated with vegetation-related Contact From Object (CFO) events. Because ODRM does not explicitly identify "fault location," geospatial analysis was used to identify the closest known SCE structure to the location information provided in ODRM. If this closest known structure was within SCE's HFRA, then the associated fault was assumed to also be in SCE's HFRA. For example, on the Thacher 16 kV circuit, a total of 8 vegetation-related CFO faults in 2015-2017 were identified to be within SCE's HFRA.

The data in th[e] column [labeled] "High Wind in HFRA Length (OH Pri – Ckt Mi.)" was based on a GIS database of SCE distribution segments found to be both within SCE's HFRA as well as in areas where pole loading is calculated using a 12 lb, 18 lb or 24 lb wind (i.e., heavy-loading areas). The information is provided in circuit miles. For example, on the Thacher 16 kV circuit, while 83.56 miles is within SCE's HFRA, 67.8 of those miles are in areas where pole loading is calculated using 12 lb or greater wind (i.e., heavy-loading areas).

SED recommends that SCE could utilize average cost for the WCCP per circuit (or conductor) mile combined with the Index Scores to provide decision-makers with more refined information to determine which circuits in high fire threat areas would get the largest wildfire risk reduction by replacing with covered conductors. In the actual spreadsheet, there are 1,336 overhead circuits ranked by Index Score. And what is very striking is the wide range of Index Score values. The Thacher OH Circuit is ranked # 1 with the highest Index Score of 39.51. There are another 3 OH circuits ranked from #2 to # 4 (Mettler, Cuddeback, & Jordan) with Index Scores higher than 30. Then there are 17 OH circuits that are ranked from #5 (Hughes Lake) to # 21 (Pioneertown) with Index Scores ranging from the highest of 28.76 to 20.36. Additional observations are listed below:

- Rank #22 (Anton) has an Index Score of 19.79 with Rank # 94 (Poultry) with an Index Score of 10.01.
- Rank # 95 (Merlin) has an Index Score of 9.84 with Rank # 771 (RMV 1243) having an Index Score of 1.00.
- Rank # 772 (Hospital) has an Index Score of .99 with Rank # 1184 (Ruttman) having an Index Score of 0.10.
- Rank # 1185 (Ariel) has an Index Score of .09 with Rank # 1310 (Eucalyptus) having an Index Score of 0.01.
- Rank # 1320 (Adell) through Rank # 1336 (Saxophone) actually show Index Scores of 0.00.

Noting the above observations, it appears that by orders of magnitude, assuming similar cost of covered conductor replacement for these circuits, that the top 94 circuits rank the highest, out of 1,336 circuits. The next order of magnitude group of circuits is quite large with 677 circuits that may need further differentiation for circuit by circuit risk spend efficiency calculations. Even better yet, line segment by line segment circuit risk spend efficiency calculations may differentiate which portions of these circuits have the greatest risk spend efficiencies.

In addition to the Index Score, the column, Potentially Mitigated HFRA Faults, appears to be important to include in risk spend efficiency per circuit calculations for covered conductor. There could be other factors to be included, too. Additionally, it appears that the Index Scores by circuit could be used for other potential mitigation measures to compare which mitigation measures would have the highest risk spend efficiency per circuit. And to improve risk spend efficiency per circuit calculations, more refined cost estimates for these circuits per circuit would improve risk spend efficiency calculations greatly.

1.3 Tree Trimmer Safety Risk Analysis with Increased Vegetation Management

In the Contact with Energized Equipment (CEE) risk assessment analysis, SED considered scenarios where increased vegetation management to reduce wildfire risks could significantly increase the number and hours that tree trimmers may be at risk for CEE. Essentially, for informational purposes, SED added scenarios in the CEE section based on SCE's February 6, 2019 Wildfire Mitigation Plan to significantly increase vegetation management due to wildfire hazards. These informational calculations were prepared to inform decision-makers that a significant increase in vegetation management could significantly increase the probability of Outcome 3, Intact Energized Wire Contact, especially if tree-trimmers are inexperienced and lack sufficient high-voltage safety training. Although SED has issues with the historical data used, SED recommends that SCE address this issue with risk analysis based on more recent and better projected data. See the CEE section for this analysis and recommendations.

1.4 Wildfire Relevant Consequences

All of SCE's Risk Assessment Modeling in its RAMP addressed the same four consequences: Serious Injury, Fatality, Reliability, and Financial. With the threat of catastrophic wildfires to California being very real especially due to the recent 2017 and 2018 wildfire tragedies, it would behoove SCE to consider whether additional wildfire relevant consequences, outside of financial consequences, would improve its risk analysis. The issue is that the current four consequences do not adequately represent the potential widespread impact of catastrophic wildfires. Suggested considerations of known and available CalFIRE data could include:

- **Acres Burned**;
- **Structures Destroyed**; and
- **Structures Damaged**.

For example, the tragic PG&E natural gas pipeline explosion in San Bruno in September 2010 had consequences including fatalities, serious injuries, reliability and financial. Comparatively, the Camp Fire, the more recent electric related tragedy in PG&E's territory, similarly had consequences to all four of these areas but also had more extensive geographic and widespread consequences that were far beyond a neighborhood and city. The recommendation to consider adding the other CalFIRE consequences into the risk analysis, beyond into the financial impact, for catastrophic wildfires could better represent the impact. It would be similar to the current method of using fatalities and serious injuries as consequences even though there may likely be financial consequences when there are fatalities and serious injuries.

Additional consideration should be given to other consequences that have impacted millions of Californians in the recent wildfire seasons. One such consequence is **Air Quality Impact (AQI)**. Millions of residents, workers and visitors in the San Francisco Bay Area experienced weeks of AQI of Very Unhealthy (AQI = 201 to 300) and Hazardous (AQI greater than 300) air quality on the U.S. Environmental Protection Agency (EPA) Air Quality Index due to the Camp Fire tragedy, the deadliest and most destructive wildfire in California history, in November 2018.

Perhaps incremental AQI after a wildfire occurs over the complete area and estimated number of people impacted by the wildfire smoke, would be something that could be created into another Consequence. This is not as straight forward as obtaining known acres burned and other data from CalFIRE but the AQI impact over each day/hour/15-minute increment for the time period that wildfire smoke is impacting California residents and workers would be helpful to truly assess consequences of a catastrophic wildfire.

Although additional wildfire relevant consequences may not be appropriate for other safety risks' analysis and would make calculating multi-attribute risk scoring (MARS) for wildfire risks more challenging for comparison purposes, it still should be seriously considered by SCE to more accurately represent the impact and calculating unmitigated and mitigated risk scores and risk spend efficiencies.

2 Analysis of Contact with Energized Equipment Risk Assessment

2.1 SCE Annualized Data for Wire-Down & Third-Party Contact Events

SED has concerns about utilizing significantly different ranges of historical years for the data sources for Risk Spend Efficiency (RSE) calculations leading to proposed mitigations. To give context, in Chapter 5, SCE's safety risk analysis is for members of the public associated with overhead conductors. In its risk assessment, SCE identified the following **two triggering events** in its bowtie risk analysis for the risk of Contact with Energized Equipment (CEE):

> **Wire-Down**: This results in conductor falling to the ground or becoming disconnected from the system in a manner that would allow the public to come in contact with it. Based on SCE's 2015-2017 Wire-Down database, this triggering event has an average frequency of 1,154 events per year.
>
> **Contact with intact overhead conductor:** This event occurs when an individual, or third party, makes contact with SCE's overhead conductor while the conductor is operating and situated as designed. Based on SCE's 2008-2016 internal records, this triggering event has an average frequency of five events per year.

SCE identified **three risk model outcomes** that represent the basic conditions existing when overhead conductor fails in service and falls to the ground, or when the public makes contact with intact overhead conductor. These outcomes, and their associated likelihood of occurrence, are in Table 1.

Table 1: Three Risk Model Outcomes

2018 CEE Outcome Likelihood			
Outcome	Name	# of Triggering Events (2018)	%
CEE O1	Energized Wire-Down	362.80	31.30%
CEE O2	De-Energized Wire-Down	791.67	68.30%
CEE O3	Intact Energized Wire Contact	4.64	0.40%
		1159.11	100.00%

Most of SCE's CEE risk analysis, along with its proposed Controls and Mitigations, examines **wire-down** triggering events drivers although SCE states that contact with **intact** energized equipment is the primary safety impact based on SCE's risk analysis. At the same time, SCE shows similarities between the drivers for **Wire-Down** events compared to the drivers for **Wildfire** events (Chapter 10) and discusses the interrelation between the proposed Controls and Mitigations for both. Hence, some of this analysis may apply to the Wildfire chapter.

SCE explained that its initial risk analysis of overhead conductor failure was in its 2018 GRC. (A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51) SCE used this risk analysis to evaluate a wide range of mitigation alternatives as well as to shape the scope definition for the mitigations selected. SCE analyzed the equipment installed on the distribution system to identify the types of conductor most commonly involved in overhead conductor failures, or a wire down event. This effort included additional engineering review of wire down events and as a result, SCE made changes to its engineering and design standards to include the standard installation of a minimum of 1/0 AWG for overhead distribution tap lines and 336 ACSR AWG for overhead distribution mainlines for all new installations. SCE implemented changes to improve its tracking of these failures in a Wire Down (WD) database. SCE used this information, combined with outage information from its Outage Database and Reliability Metrics (ODRM) system, to identify and quantify drivers, outcomes, and consequences of wire down events.

In SCE's 2018 RAMP risk modeling, SCE identified **five primary drivers (D1 to D5)** that lead to a wire-down triggering event and was able to subdivide the two main wire-down drivers (D1 – Equipment Caused, and D2 - Equipment/Facility Contact) to better understand the causes of the risks. SCE identified one primary driver, **D6 - Third Party Contact**, that leads to contact with intact energized equipment. These six main drivers, shown in Table 2, make up the primary drivers for Contact with Energized Equipment triggering events in their risk model.

Table 2: SCE 2019 RAMP Six Primary CEE Drivers

2018 Projected CEE Driver Frequency	
Name	Frequency
D1 - Equipment Caused	206
D2 - Equipment / Facility Contact	773
D3 - SCE Work / Operation	7
D4 - Unknown	168
D5 - Downstream Equipment	0
D6 - Third Party Contact	5

SCE annualized data for wire-down events (drivers D1 through D5) is based on SCE's Wire-Down database covering years 2015-2017. However, **SCE annualized data for Third Party Contact events** (driver D6) are based on SCE internal records regarding injuries or fatalities involving overhead equipment collected from 2008-2016.

SCE should explain why data for 2008-2016 Third Party Contact events are appropriate for Contact with Energized Equipment (CEE) RSE calculations. Additionally, SCE should redo the CEE RSE calculations to incorporate 2018 data for both Wire-Down and Third-Party Contact events and utilize the same years of data for CEE triggering events for comparison purposes. Since 2015 is the oldest full year that SCE has Wire-Down triggering event data, then SCE could use 2015-2018 annual average CEE triggering event data, including Third-Party Contact and Wire-Down events. One concern is that based on CPUC Reportable Fatalities & Injuries data for 2014-2018, Third Party Contact events appear to be trending in a positive direction meaning that there are fewer contact events. By using more recent data over the same historical period, RSE calculations will better inform decision-makers on comparing proposed CEE mitigation measures since the calculations.

2.2 Pole Driver

Within Equipment Cause Drivers, shown in Table 3, and in the context of SCE's Pole Loading & Deterioration Programs, it is important to note that the **pole driver** represents only a tiny fraction (i.e. 1%) of all Contact with Energized Equipment (CEE) triggering events. This is especially true since SCE did not include pole driver for Wildfire triggering events at all in its RAMP. Additionally, SCE states that "[p]ole failures that lead to wire-down events typically occur when there is deterioration at the top of pole. Pole deterioration can take place at any location on a pole. Unless the deterioration is visible, SCE's intrusive pole inspection program and pole loading assessments cannot effectively test for, or detect, deterioration at the top of the pole." This further points to the lack of root cause data related to pole failures to show the need for these programs from a risk reduction analysis. This was identified as a deficiency in the SED SCE Risk & Safety Aspects of 2018 GRC Report, Appendix A - Pole Loading Risk Assessment Methodologies Deficiencies, dated 1/31/2017.

Returning to the specific drivers in order to provide context, the **Equipment Cause driver** represents instances where SCE's equipment fails in service or fails to operate as designed, resulting in a wire-down event. Sub-categories of drivers, shown in Table 3, identify the specific type of equipment that fails although the RAMP risk model treats all sub-drivers as a single input.

Table 3: Equipment Cause Driver Sub-categories

CEE D1 Equipment Cause Frequencies				
Driver	Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D1a	Connector / Splice / Wire	130	63%	11%
D1b	Other	65	32%	6%
D1c	Pole	11	5%	1%
D1	**Equipment Cause**	**206**	**100%**	**18%**

As SCE explains, **Connectors and Splices** are two different types of devices used as a connection for overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector, and spans of conductor are connected to other spans of conductor with a splice. Both types of devices are subject to degradation due to exposure to the elements and can be damaged due to high fault current, particularly with elevated short circuit currents. In the presence of faults, these equipment types can overheat and melt, causing the overhead conductor to fall to the ground.

The **Other driver** includes all equipment drivers other than poles and connectors / splices / wires. Examples include failure of transformers, insulators, lightning arrestors, and cross arms. These types of equipment can deteriorate from age, use, and exposure to the elements.

The **Pole driver** is shown to have an annual frequency of 11 wire-down triggering events based on the historical 2015-2017 data which equates to 5% of all Equipment Cause drivers and only 1% of all CEE triggering events. For clarity, SCE states pole failure due to vehicle collision is not included in this sub-driver but is included in Sub-Driver D2e – Vehicle.

2.3 Metallic Balloons (including foil or foil-lined)

To provide context, the **Equipment/Facility Contact driver** in SCE's risk model represents instances where a foreign object has made contact with SCE's overhead conductor, resulting in the conductor failing. This driver category includes sub-categories, shown in Table 4, which identify the specific external factor that caused the equipment to fail although the RAMP risk model treats these all sub-drivers as a single input.

Table 4: Equipment/Facility Contact Drivers

CEE D2 Equipment / Facility Contact Frequencies				
Driver	Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D2a	Animal	53	7%	5%
D2b	Metallic Balloons	111	14%	10%
D2c	Other	39	5%	3%
D2d	Vegetation	171	22%	15%
D2e	Vehicle	206	27%	18%
D2f	Weather	193	25%	17%
CEE D2	**Equipment / Facility Contact**	**773**	**100%**	**68%**

As SCE states, **foil, foil-lined or metallic balloons** can potentially damage overhead electrical equipment because of their conductivity. Current California law (See Cal. Penal Code § 653.1. (Foil Balloon Law)) has recognized this and requires that all helium-filled metallic balloons be weighted to prevent escape and potential contact with overhead electrical facilities. When a metallic balloon contacts overhead lines, it can create a short circuit. The short circuit can trigger circuit damage, overheating, fire, or an explosion.

SED opines that a No-Cost solution to Metallic/Mylar Balloons, one of the Equipment/Facility Contact Drivers that makes up 10 % of all wire-down drivers, would be for SCE, along with other California electric IOUs, to advocate or continue advocating for legislation to be passed to make all conductive metallic/mylar balloons illegal in the state of California. A new regulation (or legislation) banning metallic balloons in California could eliminate or significantly reduce this driver.

2.4 Wire-Down Triggering Event Frequencies

To get a better perspective, SED combined the **Wire-Down Triggering Event Frequencies** into Table 5, with some annotations based on information from SCE's RAMP risk modeling results. These wire-down triggering event frequencies are addressed further in discussion of SCE's proposed Control measure, Overhead Conductor Program.

Table 5: Wire-Down Triggering Event Frequencies

Wire-Down Triggering Event Frequencies		
Name	**Annual**	**%**
Connector / Splice / Wire	130	11%
Other Equipment Cause	65	6%
Pole (normally top degradation)	11	1%
Animal (e.g. squirrel, bird etc.)	53	5%
Metallic Balloons	111	10%
Other (e.g. Gunshot damage, Drones, etc.)	39	3%
Vegetation	171	15%
Vehicle Accidents (usually into pole)	206	18%
Weather	193	17%
Unknown	168	15%
TOTAL Annual Triggering Events:	1147	100%

2.5 Compliance and Controls

SCE included an inventory of **Compliance and Controls** (SCE RAMP Table III-1) that are in place today to address Contact with Energized Equipment risks, shown as Table 6. SCE included four controls as compliance activities and did NOT model them in their RAMP risk analysis. Three Controls activities were modeled including risk spend efficiency (RSE) calculations. SCE claims that Compliance activities are required by law or regulation.

Table 6: Compliance and Controls

Table III[illegible]1 – Inventory of Compliance and Controls[23,24]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Distribution Deteriorated Pole Remediation Program and Pole Loading Program (PLP) Replacements	Not Modeled	Not Modeled	Not Modeled	$ 273.9	$ 30.9
CM2	Vegetation Management	Not Modeled	Not Modeled	Not Modeled	$ [illegible]	$ 84.3
CM3	Overhead Detailed Inspection, Apparatus Inspections, and Preventive Maintenance	Not Modeled	Not Modeled	Not Modeled	$ [illegible]	$ 36.0
CM4	Intrusive Pole Inspections and Pole Loading Assessments	Not Modeled	Not Modeled	Not Modeled	$ [illegible]	$ 6.0
C1	Overhead Conductor Program (OCP)	D1a[illegible]b, D2a[illegible]d,f	[illegible]	[illegible]	$ 138.7	$ [illegible]
C1a	Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor	D1a[illegible]b, D2a[illegible]d,f	O1	SI, SF	$ [illegible]	$ [illegible]
C2	Public Outreach	[illegible]	O1, O3	SI, SF	$ [illegible]	$ 5.1

2.5.1 Compliance 1 (CM1) - Distribution Deteriorated Pole Remediation Program & Pole Loading Program Replacements

The first Compliance program, CM1, is entitled **Distribution Deteriorated Pole Remediation Program and Pole Loading Program (PLP) Replacements**. SCE's Distribution Deteriorated Pole Remediation Program captures the costs to replace or stub distribution poles which have failed an intrusive pole inspection. The Distribution Pole Loading Program (PLP) captures costs to assess all poles within SCE's service territory and replace those which fail the applied wind-loading measurement. The costs for both programs are recovered through SCE's Pole Loading and Deteriorated Pole Balancing Account (PLDPBA). SCE states that these two programs proactively identify poles that represent an increased probability of pole failure. Through these programs, SCE takes action to replace such poles with new assets that meet pole design standards and criteria.

In SED-SCE-Verbal-001 Question 1 Data Request Response on 1/3/2019, SCE states: "In its 2015 GRC, A.13-11-003, SCE proposed the Pole Loading Program. As discussed in that proceeding in Exhibit SCE-03, Volume 6, Part 2, the Pole Loading Program was designed to address concerns about SCE's poles not meeting certain compliance requirements for design criteria established in General Order 95. SCE proposed to conduct a complete assessment of non-engineered poles in its inventory over a seven-year period and identify and remediate non-compliant poles over a twelve-year period. In D.15-11-021, the Commission adopted SCE's proposal to conduct this program. The Commission adopted the seven-year timeframe for assessment. See D.15-11-021, p. 123 ("We adopt SCE's proposed assessment schedule"). The Commission also modified certain aspects of the proposed funding. The Commission authorized a balancing account to track various pole-related expenditures. Based on the Commission adopting a program designed to bring SCE poles into compliance with Commission standards and adopting a balancing account that limits SCE's ability to redirect adopted pole funding, SCE determined that the Pole Loading program should be classified as a Compliance measure for RAMP purposes."

First, SED disagrees with SCE's opinion this program is a compliance program. Specifically, and at a minimum, SED believes there are portions of the Pole Loading Program (PLP) Replacements that are not compliance based. SED is aware of the PLP program and it is a mix of compliance and controls due to the fact that SCE has its own internal standards that have differing requirements than the Commissions General Orders. For example, SCE has areas that it considers high fire areas (HFAs) that are not included in CPUC designated High Fire areas. Additionally, SCE has higher wind loading standards and potentially other higher standards than GO 95 minimal requirements. These should be considered Controls and not Compliance. SCE needs to split this program into Deteriorated Pole Remediation Program and Pole Loading Program Replacements and at a minimum, model the controls portion to calculate Risk Spend Efficiencies for these programs to inform decision-makers as to the relative benefit of these programs in reducing safety risks. This is especially necessary as these are high cost programs that were requested for authorization by SCE to reduce safety risks. Risk reduction analysis including RSEs would be most appropriate for decision-makers to be able to assess programs based on SCE's internal standards based on safety risks and costs.

Additionally, based on SCE's RAMP, SED disagrees that this program would materially reduce the frequency of pole-related drivers of wire-down events since SCE claims they are usually related to pole-top deterioration. Hence, it behooves SCE to include which triggering events these high cost programs are mitigating and to do Risk Spend Efficiency calculations based on relevant triggering events based on actual historical event data.

2.5.2 CM3 - Overhead Detailed Inspection, Apparatus Inspections, and Preventative Maintenance/ Distribution Inspection and Maintenance Program (DIMP)

CM3, **Overhead Detailed Inspection, Apparatus Inspections, and Preventative Maintenance**, are activities included under **SCE's Distribution Inspection and Maintenance Program (DIMP)**. Per SCE, 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 and maintains system reliability; and (3) delivers overall greater safety value for each dollar spent by allowing SCE to focus its limited resources on higher priority risks. These activities address all distribution overhead assets in the SCE system.

DIMP enables SCE 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 enables SCE to prioritize resources effectively and efficiently to remediate conditions that potentially pose higher risks. SCE states 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 considering the factors discussed previously. Highest priority items requiring immediate action are assigned Priority 1. Priority 2 items do not require immediate action but require corrective action within a specified time period. Priority 1 and Priority 2 items may be fully repaired or temporarily repaired and reclassified as a lower priority item. Priority 3 items are lower priority items that involve little or no safety or reliability risk. SCE responds to Priority 3 conditions by taking action at or before the next detailed inspection, which may include re-inspection, reassessment, or repair. These maintenance priorities are also utilized by Troublemen when responding to trouble calls and emergency situations. A summary of the DIMP maintenance priority levels was provided in Table 7 from SCE's RAMP (Table III-2).

Table 7: Summary of DIMP maintenance priority levels

Table III-2 – 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 95/128 issue identified	Action at or before next detailed inspection
none	No	No GO 95/128 issue identified	Monitor condition during course of inspection cycles

SCE states these activities proactively identify conditions of existing assets that require mitigation to prevent failure. This compliance control performs such mitigations and reduces the frequency of equipment-related drivers of wire-down events. SED believes that the DIMP program could be expanded to incorporate further risk analysis especially if higher levels of resources were allocated for field inspections.

2.5.3 CM4 - Intrusive Pole Inspections and Pole Loading Assessments

SCE states that Intrusive Pole Inspections and Pole Loading Assessments involve inspecting or assessing existing distribution poles to execute the activities described in the Distribution Deteriorated Pole Remediation Program and PLP described above. SED reiterates here that SED disagrees with SCE's claim that as an enabling activity for compliance control CM1 above, this control helps reduce the frequency of pole-related drivers of wire-down events due to the fact that SCE also claims that most pole-related drivers of wire-down events are due to pole-top deterioration which is difficult to assess by intrusive pole inspections or pole loading assessments.

2.5.4 Control 1 (C1) - Overhead Conductor Program (OCP)

For Control 1 (C1), **Overhead Conductor Program**, of note is that SCE states consistent with existing OCP scoping practice, C1 is modeled as including the use of bare overhead conductor and representing 100% of the OCP expenditures for years 2018 through 2020. Because SCE also anticipates future use of covered conductor in non-High Fire Risk Areas (HFRA), C1 is modeled as representing only 90% of the OCP expenditures for years 2021 through 2023. The remaining 10% of the OCP expenditures for years 2021 through 2023 is included in C1a “Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor” as described below. Since, at this time, SCE does not know the exact percentages of bare versus covered conductor for future OCP projects in non-HFRA and the 90% and 10% values for years 2021-2023 are assumed percentages for modeling purposes, SED believes this is another important opportunity to use detailed circuit/line segment risk spend efficiency calculations to provide decision makers with quantitative data on how to prioritize the implementation of this program. (See discussion later in this appendix.)

As for Drivers impacted by the OCP program, the OCP impacts the triggering event frequency associated with Drivers D1 (Equipment Cause), and D2 (Equipment /Facility Contact). The OCP will reduce the frequency of wire-down events associated with D1 by reducing the frequency of faults. This is because the OCP replaces small, spliced, or damaged conductor with larger, more resilient conductor. The OCP will reduce the frequency of wire-down events associated with Driver D2 not by reducing the frequency of faults, but by reducing the number of faults that lead to wire-down events. Faults listed in D2 are external events that will continue to occur regardless of the OCP. However, the upgrades performed in OCP will create a more resilient system that will be less susceptible to damage as a result of such faults.

On WP page 5.4, D1, the mitigation effectiveness of Equipment Cause driver, is assumed to be 10.9% in 2018 growing significantly each year to 55.9% in 2023. SCE states the model increases based on the year-to-year deployment rates. Additionally, D2, Equipment / Facility Contact, is assumed to be 3.0% in 2018 and grows to 15.5% in 2023 for the same reasoning. The other drivers are not impacted by this control.

Based on SCE’s Workpapers page 5.12, the Driver Analysis for the OHP is based on 1,965 overhead circuit miles reconductored in 2018-2023. The initial driver frequency used in the analysis does not include the 168 Unknown drivers in SCE’s Wire-Down Triggering Event Frequencies totaling 1,147 annual average events which were previously 15% of this total. Hence, SCE’s analysis is based on about 85% of the known wire-down triggering event types. Table 8 shows the known wire-down triggering event annual frequencies.

Table 8: Wire-Down Triggering Event Annual Frequencies

Wire-Down Triggering Event Frequencies		
Name	**Annual**	**%**
Connector / Splice / Wire	130	13%
Other Equipment Cause	65	7%
Pole (normally top degradation)	11	1%
Animal (e.g. squirrel, bird etc.)	53	5%
Metallic Balloons	111	11%
Other (e.g. Gunshot damage, Drones, etc.)	39	4%
Vegetation	171	17%
Vehicle Accidents (usually into pole)	206	21%
Weather	193	20%
TOTAL Annual Triggering Events:	979	100%

SCE uses a 5.5% deployment based on taking the ratio of expected OH circuit miles to be reconductored (1,965) over the total OH circuit miles in SCE's distribution system (36,040). SCE states it expects to reconductor a total of 1,965 circuit miles by 2023.

SCE uses its Distribution Engineering's Subject Matter Expertise (SME) to inform input on overall effectiveness for this mitigation for each sub driver. SCE has 5 broad drivers for these assumptions and the first three are transparent as follows:

1. Arcing and melting are the two failure modes for overhead conductor.
2. Reconductoring is assumed to be 50% effective against arc failures and 90% effective against melt failures.
3. Branch Line Fusing (BLF) is assumed to be 0% effective against arc failures and 90% effective against melt failures.

The other two assumptions are non-transparent as SCE said is made different assumptions for the mix of failure modes for each individual driver and as needed, further adjustments were made to account for the deployment of both reconductoring and BLF mitigations in order to avoid double counting of benefits.

Based on these assumptions, the OCP has the highest mitigation effectiveness on Equipment Cause drivers. Specifically, 90% effectiveness for Connector/Splice/Wire and 80% effectiveness for Other Equipment Causes. (0% for Pole related drivers.) Additionally, the next greatest mitigation effectiveness was for Animal contact (55%), Other Contact like gunshot damage and drones (46%), Mylar Balloon (32%), Weather (28%) and Vegetation (24%). Vehicle (e.g. hitting pole/equipment) driver has 0% effectiveness.

The next significant assumption in SCE's Control C1 (OCP) Driver Analysis is the assumption that the expected risk reduction of 5.5% deployment would reduce the baseline wire-down risk by

20%. SCE states that the 20% risk reduction was based on analysis considering frequency reduction only. It is unclear to SED why and how this assumption was made and hence, should be expanded on.

SCE continues in their OCP Driver Analysis that a 20% frequency reduction is approximately equivalent to an annual average driver frequency reduction of 235 (from 979 total wire-down triggering events). Hence, SCE worked backwards in to calculate the targeting benefit to come up with a reduced total of 745 wire-down triggering events.

Table 9 shows SCE's average annual wire-down triggering event frequencies and the percentages of the original projected 2018 total (i.e. average of 2015-2017) and how SCE made the back calculation spread over the events to get a total of 20% less.

Table 9: SCE Average Wire-Down Triggering Event Frequencies

Wire-Down Triggering Event Frequencies						
Name	Annual	%	20% Less	New %	New/Old	
Connector / Splice / Wire	130	13%	50	7%	38%	#1
Other Equipment Cause	65	7%	30	4%	46%	#2
Pole (normally top degradation)	11	1%	11	1%	100%	
Animal (e.g. squirrel, bird etc.)	53	5%	33	4%	62%	#3
Metallic Balloons	111	11%	87	12%	78%	#5
Other (e.g. Gunshot damage, Drones, etc.)	39	4%	27	4%	69%	#4
Vegetation	171	17%	144	19%	84%	#7
Vehicle Accidents (usually into pole)	206	21%	206	28%	100%	
Weather	193	20%	157	21%	81%	#6
TOTAL Annual Triggering Events:	979	100%	745			

Table 9 also shows a column 'New %' to show the new percentage of the new projected total after the mitigation. Additionally, another column 'New/Old' to compare the percentage of each wire-down triggering event to show the mitigation effectiveness for each specific event type. For example, for Connector/Splice/Wire events, 'New/Old' percentage is calculated as 50 divided by 130 to equal 38%. The lower the percentage actually means the greater the effectiveness which is somewhat counter intuitive. (In future analysis, perhaps subtracting this percentage from 100% would be a better way to show the intent.) The last unnamed column ranks the events from highest (#1) mitigation impact to lowest (#7) without numbering the highlighted ones that are not mitigated to rank the mitigation effectiveness based on annual events per mitigation type.

Another way to evaluate this analysis is to recombine into Equipment Cause versus Equipment/Facility Contact drivers since the Monte Carlo probabilistic modeling did not use sub-driver specific data. Table 10 shows this recombined below.

Table 10: Alternative Analysis of Wire-Down Triggering Event Frequencies

Wire-Down Triggering Event Frequencies					
Name	Annual	%	20% Less	New %	New/Old
Equipment Cause	206	21%	91	12%	44%
Equipment / Facility Contact	773	79%	654	88%	85%
	979	100%	745	100%	

Table 10 shows that the greatest mitigation effectiveness is for Equipment Cause drivers. This is also shown in the SCE RAMP Workpapers, as the overall Mitigation Percent for Equipment Cause is 55.9% while the Equipment/Facility Contact driver percent is only 15.5%.

2.6 CEE Combined Risk Analysis

SCE defines CEE risks as those safety risks for members of the public coming into contact with energized overhead conductor, whether the conductor is a wire-down, or remains intact. SCE does not include in CEE risk analysis scope the following: third party contractors; attempted vandalism or theft of SCE equipment or property; substation or transmission equipment; or excavation that contact underground distribution or transmission lines. Although some of the drivers may be different, there may be additional risk analysis that may be further conducted if contact with or near distribution high voltage energized equipment risks were evaluated together for distribution lines. Additional risk analysis for substation risks and for transmission equipment should also be done and consideration to whether combined risk analysis for all contact with energized equipment risks should be considered.

2.7 Arc Flash (Non-direct contact with energized equipment) Risks

Additionally, it would be useful to understand whether contact with energized equipment risks include arc flash risks, which do not require direct contact with energized equipment and have been well studied in the past decade in the electric power industry. This was not explicitly addressed in the CEE chapter including for third party contacts with intact energized equipment.

2.8 Risk Analysis of Design, Construction & Operation including Grounding Methodologies

As SCE states, its distribution system is constructed with protection equipment that stops the flow of electricity when a foreign object contacts the line and causes a fault. SCE also states that if the fault is temporary and hasn't resulted in damage, electricity flow can typically be restored relatively quickly (in seconds or minutes) through an automatic operation referred to as a circuit "reclose". SCE states that if the fault is permanent or has resulted in damage to infrastructure, then the electricity flow will remain interrupted which is referred to as a circuit "lockout" requiring field personnel to be deployed to locate and repair the problem.

As for assessing risk reduction of contact with energized equipment events, an analysis of SCE's design, construction and operation of its overhead electric power system, including grounding methodologies, may be useful. Specifically, areas of system-wide risk analysis could evaluate wye versus delta three phase systems (especially as it related to grounding methodologies) and whether multi-grounded system grounding conductors are utilized. The reason for this type of analysis is that these design/construction/operational factors may impact the ability for protection equipment to detect faults. This is important to mitigate the risk of energized wire-down events. Based on approximately 3.5 years of data and conservative estimations for unknown events, SCE energized wire-down events had a likelihood of 31% outcomes compared to de-energized wire-down event outcomes of 68%. It would be helpful for SCE to provide comparative statistics to other U.S. electric distribution systems to know if SCE's estimated percentage of energized wire-down events is similar to other utilities.

2.9 Circuit/Line Section/Line Segment Risk Analysis

The electrical definitions of circuit, line section and line segment are necessary to include here in order to explain SED's circuit/line segment risk analysis recommendation more fully. From The New IEEE Standard Dictionary of Electrical and Electronics Terms, Fifth Edition (IEEE Std 100-1992), the electrical definitions below are helpful to understand SED's recommendation:

> **Circuit (NESC)**: A conductor or system of conductors through which an electric current is intended to flow. (C2-1984)
>
> **Line Section:** A portion of an overhead line or a cable bounded by two terminations, a termination and a tap point, or two tap points. (859-1987)
>
> **Line Segment:** A portion of a line section that has a particular type of construction or is exposed to a particular type of failure, and therefore which may be regarded as a single entity for the purpose of reporting and analyzing failure and exposure data. Note: A line segment is a subcomponent of a line section. (859-1987)

It is noteworthy in the definition of Line Segment that it is not only defined as a line section with a particular type of construction but also can be defined as a portion of a line section that "**is exposed to a particular type of failure**". The fact that this definition is at least 30 years old in the electric power industry, emphasizes that electric utilities have been analyzing failures of segments of electric line segments for decades.

With the advancement of technology to collect and analyze electric power data, SED believes that data should be available to be analyzed on a line segment basis for risk analysis purposes. And based on the Line Section definition, perhaps more accurate reference to line sections with discrete termination points rather than circuits may be beneficial for risk analysis purposes. Hence, SED recommends more refined risk analysis circuit by circuit or better yet, line section by line section and even line segment by line segment, would be feasible and worthwhile.

More detailed risk spend efficiency calculations by circuit or line segment could be very valuable to determine where fault detection and/or system hardening or other measures provide the highest risk reduction benefits. Risk spend efficiencies (RSEs) could be calculated by circuit (or more ideally by line section or line segment) since circuit prioritization has been conducted by SCE to prioritize system hardening and other mitigation measure deployment and implementation (e.g. undergrounding, etc.).

2.9.1 Wildfire Covered Conductor Program (WCCP) Prioritization of Circuits Index Score for RSEs

SED believes that the Index Score used for the Wildfire Covered Conductor Program to prioritize circuits for implementation of deployments could be utilized in RSE calculations combined with average cost of covered conductor replacement per circuit or conductor mile. This is explained further in the Wildfire section above.

2.10 Third Party, especially Tree Trimmers, Safety Risk Analysis

SCE states that although only 0.4% of CEE outcomes (public only) are likely to result in intact energized wire contact, it is still the primary safety impact based on SCE's risk analysis. From SCE's RAMP Workpapers, SED calculated that inputs for Serious Injury and Fatality is 183 and 160, respectively, times higher for Intact Energized Wire Contact (Outcome 3) than Energized Wire Down (Outcome 1). But as SED discussed previously, these data sources are over significantly different historical periods and so this may not be an effective way to assess risk spend efficiencies for relevant mitigation measures. Based on the SCE data available, SED used RAMP workpaper data for Outcomes 1 and 3 and did not include Outcome 2 since SCE assumed it did not have fatality or serious injury outcomes in Table 11 below.

Table 11: CEE Consequence Details for Outcomes 1 and 3

CEE Consequence Details for Outcomes 1 and 3 (not 2 since SCE did not do for SI or Fatality)			
		Serious Injury (SI)	**Fatality**
Model Inputs	Data/sources used to inform model inputs	Incidents involving SCE OH conductor that resulted in serious injuries, from 2008-2016	Incidents involving SCE OH conductor that resulted in fatality, from 2008-2016
For Outcome O1*	Input 1	0.000	0.000
	Input 2	0.000	0.000
	Input 3	0.00919	0.00738
Model Outputs for Outcome O1	NU Mean	1.1	0.9
	NU Tail Avg	1.2	1
For Outcome O3*	Input 1	0.000	0.000
	Input 2	0.000	0.000
	Input 3	1.68677	1.17647
Model Outputs for Outcome O3	NU Mean	2.8	2.0
	NU Tail Avg	5.9	4.1
*Triangular Distribution: SCE chose a triangular distribution since this is not a long "tail" consequence.			

As shown in the below calculations, SED compared Input 3 for Serious Injury (SI) for Outcome 3 compared to Outcome 1 to calculate that it is 183 times higher for Outcome 3. Similarly, SED compared Input 3 for Fatality for Outcome 3 compared to Outcome 1 to calculate that it is 159 times higher for Outcome 3.

SI Input 3 Ratio = O3 SI Input 3 / O1 SI Input 3 = 1.68677 / .00919 = 183.5
Fatality Input 3 Ratio = O3 Fatality Input 3 / O1 Fatality Input 3 = 1.17647 / .00738 = 159.4

This means that if there is an event where there is contact with an intact energized wire, then there is 183 times higher probability that there will be a serious injury and 159 times probability that there will be a fatality as compared to if there is an event where there is an energized wire-down. This intuitively makes sense because in Outcome 1, Energized Wire-Down, there is not necessarily a human being nearby the event whereas with Outcome 3, Intact Energized Wire Contact, there is necessarily a human being making contact with the overhead energized wire.

SED notes that the Outcome Likelihood is based on that for all three outcomes, these two outcomes (O1 and O3) are only 31.7% of all the outcomes. Specifically, Outcome 1, Energized Wire-Down, is assumed to have 31.3% of an outcome likelihood in compared to all 3 outcomes (including Outcome 2, De-Energized Wire-Down). And Outcome 3, is assumed to have a 0.4% outcome likelihood when compared to all 3 outcomes.

Hence, SED calculated the percentage of Outcome 1 and Outcome 3, shown in Table 12, compared to the total of only those two outcomes. 98.7% of those outcomes would be likely to be O1 and 1.3% of those outcomes would be likely to be O3. (see below)

Table 12: Outcome Likelihood

Outcome Likelihood			
	All 3 Outcomes	**Only Outcome 1 & 3**	**O1 vs O3**
O1	31.30%	31.30%	98.74%
O2	68.30%	n/a	
O3	0.40%	0.40%	1.26%
	100.00%	31.70%	

SED used simple calculations (Input O3/Input O1) to check the basis of the model outcomes and came to similar enough outputs as shown in Table 13 below.

Table 13: SED Outcome Calculations

	SI Inputs 3 (Mean)	**Fatality Inputs 3 (Mean)**
O1	0.00907	0.00729
O3	0.02128	0.01485
O3/O1	234.6%	203.7%
Model Outputs O3 / Model Outputs O1	254.5%	222.2%

Additionally, for informational purposes, SED added a scenario to increase the likelihood of Outcome 3 based on ongoing policy discussions to significantly increase vegetation management throughout the state of California due to wildfire hazards. These informational calculations were prepared to inform decision-makers that a significant increase in vegetation management could significantly increase the probability of Outcome 3, especially if tree-trimmers are inexperienced and lack sufficient high-voltage safety training.

Assuming Input 3 for Outcome 3 was increased by 1 for both SI and Fatality, then the ratio for O3/O1 would increase to 373.6% for SI and 376.9% for Fatality. If Input 3 for Outcome 3 were increased by 2 for both, then the ratio for O3/O1 would increase to 512.7% and 550.1% for SI and Fatality, respectively. If Input 3 for Outcome 3 were increased by 3 for both, then the ratio would increase to 651.7% and 723.2%, respectively.

Since SCE also states that high risk workers include tree trimmers and agricultural workers for this outcome and in light of the recent expedited effort to increase vegetation management mitigation work to decrease the likelihood of wildfire events, SCE may be wise to put an increased amount of risk reduction effort into preventing fatalities and injuries from contact with intact energized equipment and arc flash risks for tree trimmers. But SED notes again that this latter analysis on Outcomes 1 and 3 is based on significantly different historical ranges of years. SCE should present new risk analysis using more recent and similar years for its Wire-Down and Third-Party Contact events (i.e. 2015-2018), then SCE should consider whether this type of analysis focused on outcomes that do have fatality and serious injury outcomes would be beneficial.

– **END OF APPENDIX C** –

APPENDIX D – EMPLOYEE, CONTRACTOR SAFETY CRITIQUE AUTHOR: JEREMY BATTIS

Chapter 7 - Employee and Contractor Safety ***(pp.239/243 – 279 pdf)***
All page references denote numbering in the pdf version

SUMMARY
SCE's chapter on Employee and Contractor Safety touches on field-worker injuries along with describing careful vetting practices in place for hiring of contractors. The chapter also describes ongoing implementation of a sweeping utility-wide safety culture reboot that would confront and change old habits and attitudes so as to remake Edison as a safety-first organization. Even so, the primary thrust of Chapter 7 is to address issues of minor injury that occur in the office such as slip and fall or repetitive stress injury.

SED Generated Table 7-1: ***Summary of Risk, Reduction, Cost, and Spending Efficiency***

	B	C
1		
2	MARS-EV Existing Baseline annual	6.98
3	MARS-EV Proposed Plan Risk Score Reduction (annual)	0.53
4	MARS-EV Proposed Plan Risk Score Reduction (all years)	3.18
5		
6	MARS-TA Existing Baseline annual	10.01
7	MARS-TA Proposed Plan Risk Score Reduction (annual)	0.41
8	MARS-TA-Proposed Plan-Risk Score Reduction (all years)	2.48
9		
10	*RSE Units of Risk Reduced Per Million Dollars:*	
11	MARS-EV Proposed Plan Total RSE (Units/$ Millions)	0.04
12	MARS-TA Proposed Plan Total RSE (Units/$ Millions)	0.03
13		
14	*2017 Baseline Controls and Mitigations:*	
15	Recorded control expense costs	69.16
16	Recorded control capital costs	-
17		
18	*2018-2023 Cost in Millions of Dollars:*	
19	Mitigation plan O&M (annual average)	4.60
20	Mitigation plan capital costs (annual average)	8.63
21	Mitigation plan costs for control measures (annual avg)	2.53
22	Mitigation plan total six-year cost	79.4

Note that 2017 baseline control expenses include $68.7 million in expenses to comply with Federal regulations (CM controls). Excluding these costs, 2017 baseline control costs totaled less than $0.5 million, compared to about $2.5 million budgeted annually beginning 2018. SED points this out as Edison's proposed 2018-2023 program costs do not account for Federal regulations compliance (CM controls) costs; Edison's planned 2018-2023 CM costs are not disclosed in the RAMP chapter.

Edison proposes an approximately $79.3 million total cost, six-year mitigation plan, expected to reduce the Risk by 0.53 annual MARS units with an estimated RSE of 0.031. Note that SCE's total cost figure based on the annual $13.2 million cost figure provided in Table I-2, below, does not align perfectly with the cost estimate it provides in Figure V-1, also below (the former has a total cost of $79.2 million, with the latter pegged at $79.4 million).

With Edison's annual baseline Employee and Contractor Safety risk estimated at 6.98 MARS units, SCE's resulting mitigated Risk would be 6.45 annual MARS units (*a risk reduction of less than eight percent*). At an annual cost of more than $13 million, and with a baseline annual serious injury count of 15 per year and a baseline annual fatalities count of just one per year, SCE's Chapter 7 risk plan does not move the needle on the risk reduction meter by much.

Essentially, it seems, for a $13 million annual cost, Edison avoids perhaps one serious injury per year.

A more lenient appraisal of SCE's risk program might discount controls already in place, which SCE credits with already having reduced incidence of injury and death to the low rates that now exist. Edison projects control measures total cost for the six-year period 2018-2023 at $15.2 million (shown in Figure V-1). Thus removing control measure costs from the equation would reduce SCE's expense burden by less than twenty percent. In other words, at best, SCE could foreseeably avoid one serious injury per year at a mitigation-measure-only (i.e., exclusive of control measure expenses) cost of $11 million per year. (Then again, for reasons outlined in the chapter's Drivers section below, this conclusion may not hold as SCE's past controls spending and its proposed future spending are something of an oranges-to-apples comparison.)
Table below pulled from p. 246

Table I-2 – Summary Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Safety Controls	X	X	X
C2	Contractor Safety Program	X	X	X
M1a	Safety Culture Transformation – Core Program	X		X
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards		X	
M2	Industrial Ergonomics	X	X	X
M3a	Office Ergonomics – Core Program	X	X	X
M3b	Office Ergonomics – Additional Software		X	
M4a	Driver Safety Training – Full Training Population		X	
M4b	Driver Safety Training – Limited Training Population			X
Mean (MARS)	*Cost Forecast ($ Million)*	$13.2	$15.1	$13.5
	Baseline Risk	6.98	6.98	6.98
	Risk Reduction (MRR)	0.53	0.59	0.54
	Residual Risk	6.45	6.39	6.44
	Risk Spend Efficiency (RSE)	0.040	0.039	0.040
Tail Average (MARS)	*Cost Forecast ($ Million)*	$13.2	$15.1	$13.5
	Baseline Risk	10.01	10.01	10.01
	Risk Reduction (MRR)	0.41	0.47	0.43
	Residual Risk	9.60	9.54	9.58
	Risk Spend Efficiency (RSE)	0.031	0.031	0.032

Figures represent 2018 - 2023 annual averages.

For Chapter 7, Edison does not provide adequate risk summary narrative or tables, with clarity suffering as a result.

To remedy this situation, SED assembled Table 7-2, below, an injury and fatality (and other outcome) summary that shows in one place SCE data provided piecemeal in the RAMP chapter submittal. Table 7-2 indicates that Chapter 7 total risk would account for about 15 serious injuries per year; one fatality per year; approximately 360 million Customer Minutes Interrupted; and approximately $24 million in financial consequences.

To promote ease of review and greater transparency, Edison should provide such an outcome table for all future RAMP and GRC risk chapters. Also, because it would be valuable as a comparison metric, going forward SCE should cite each risk's rank in terms of cost and RSE within both narrative and a table.

Note that in Chapter 7 SCE does not attempt to provide data that would differentiate injuries as superficial, minor, or severe. Rather, SCE explains that it is working to attain this level of granularity, and that Chapter 7 includes only injuries typified as serious (p. 277). Thus Table 7-2 presents only those injuries that SCE has categorized as serious.

SED Generated Table 7-2: *Summary of Outcome Impacts*

	A	B	C	D	E	F	G	H	I	J
1										
2			Injuries		Fatalities		Reliability	(CMI -Ms	Financial	($1,000s)
3			*Mean*	*Tail Avg*	*Mean*	*Tail Avg*	*Mean*	*Tail Avg*	*Mean*	*Tail Avg*
4		O1 non-report	-	-	-	-	7.6	8.4	24	26
5		O2 field	9.51	17.87	0.50	0.94	231	435	-	-
6		O3 electrial	5.25	10.39	0.50	1.13	121	275	-	-
7		O4 office	0.36	1.41	-	-	-	-	-	-
8		O5 vehicle	0.25	2.04	-	-	-	-	0.3	2.8
9										
10		**sum**	**15.37**	**31.71**	**1**	**2.07**	**359.6**	**718.4**	**24.3**	**28.8**

Table 7-2 illustrates modeled baseline annual adverse outcomes attributable to Chapter 7 risks.

STRENGTHS

Edison demonstrates good subject matter expertise and a fundamental grasp of the organization's vulnerabilities and weak areas to be addressed. SED appreciates SCE's acknowledging that it has room for improvement in its safety practices.

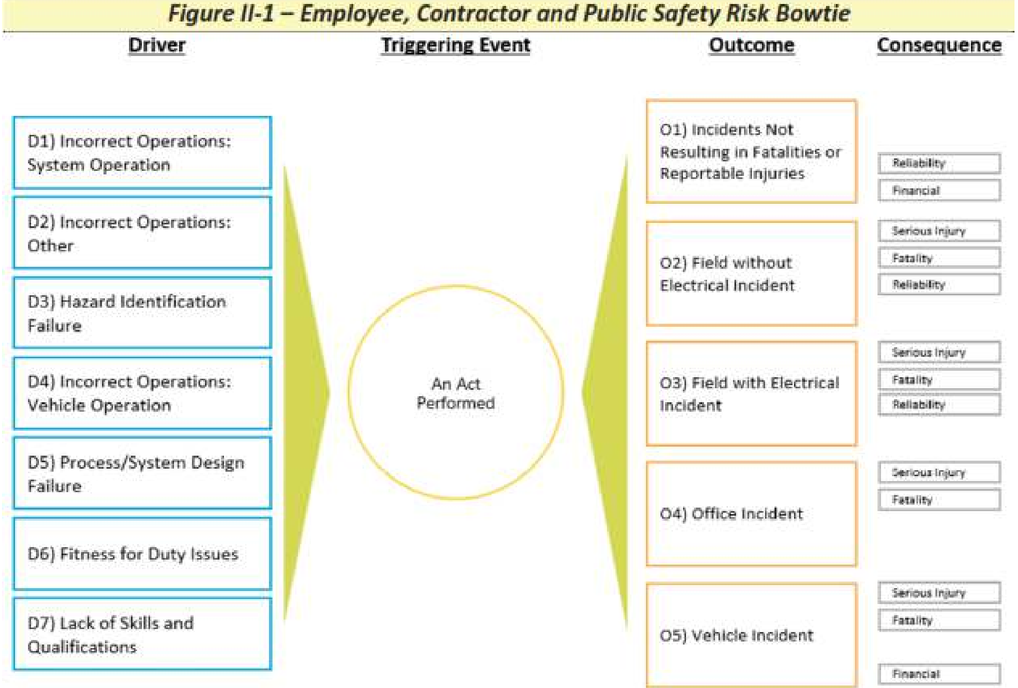
AREAS FOR IMPROVEMENT

Concerns with Bowtie Analysis
Edison's Bowtie should be reworked. The triggering event at its center is vague and undefined. The drivers do not clearly characterizehow they combine with a Triggering Event to result in various outcomes. SCE should explain and justify why financial and reliability outcomes should be considered within a RAMP safety assessment. Edison also does not provide an explanation as to why its RAMP Report, submitted to the Commission near the end of 2018, includes 2018 as the first year of its six-year risk mitigation program

Concerns with Plan Alternatives
As discussed below, Edison fails to provide three bona fide plan alternatives, but rather offers alternatives that are variations on a preferred alternative. This not meet basic expectations and requirements for a RAMP risk assessment. SCE is expected, within all future risk chapter submittals, to describe two viable Risk mitigation plan alternatives in addition to a preferred alternative.

Risk Bowtie, Risk Drivers, and Triggering Events
Employee and Contractor Safety Chapter 7 Risk Bowtie Schematic (Table below pulled from p. 249)

Figure II-1 – Employee, Contractor and Public Safety Risk Bowtie



Edison's Chapter 7 risk bowtie, shown above, on first pass seems unnatural and not intuitive. To start with, the worker safety risk Triggering Event "An Act Performed" is passive and undefined, and too vague to be of much value. SCE does not make a clear and persuasive case for how its identified risk drivers, when brought to bear by a Triggering Event catalyst, would result in an identified outcome.

A risk bowtie as a simplified schematic is probably an imperfect tool by nature, but SED is sharing here for SCE's consideration the approach PG&E used for its bowtie diagrams. PG&E incorporates exposure and frequency, resulting in somewhat more well defined drivers.

Examples of PG&E Risk Bowtie Schematic Methodology

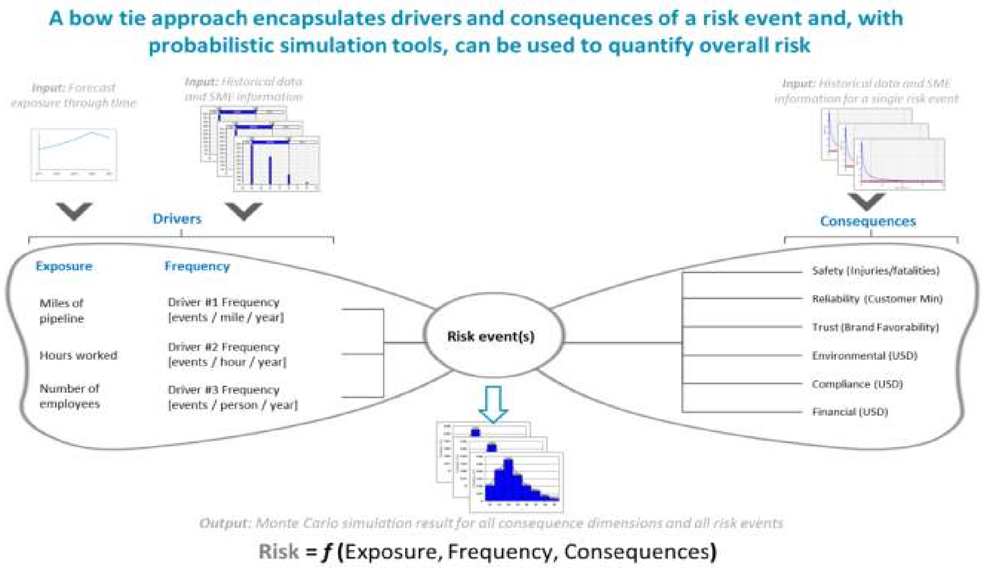
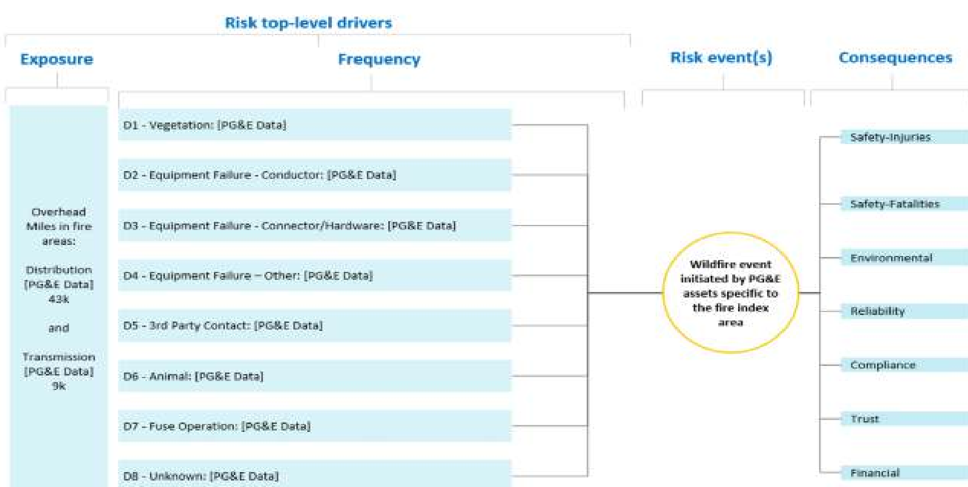


FIGURE 2A-4
WILDFIRE RISK BOW TIE

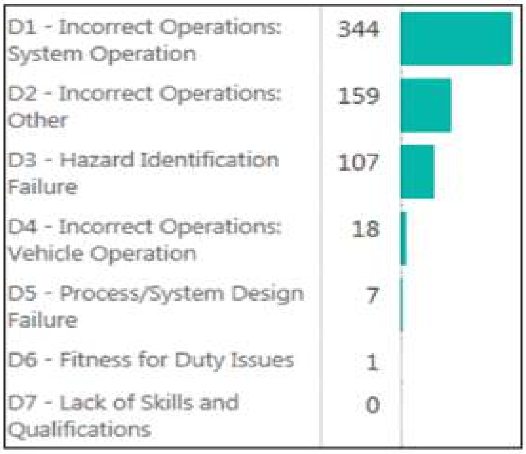


Drivers

SCE derives the Frequency for a Chapter 7 Triggering Event by summing the estimated annual frequencies of its seven drivers D1 –D7.

Table below pulled from p. 249

Figure II-2 – 2018 Projected Driver Frequency



SED notes Edison's Driver frequency growth table, shown below. SCE explains that its risk Driver Frequency growth is flat, at least in part due to existing controls that SCE believes have been effective at reducing incidents and resulting injuries and other outcomes.

Table below pulled from p. 252

Figure II-3 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	Total
Employee, Contractor and Public Safety							
Baseline	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**3,824.49**
Driver							
D1 - Incorrect Operations: System Operation	344.17	344.17	344.17	344.17	344.17	344.17	**2,065.03**
D2 - Incorrect Operations: Other	159.32	159.32	159.32	159.32	159.32	159.32	**955.95**
D3 - Hazard Identification Failure	106.56	106.56	106.56	106.56	106.56	106.56	**639.38**
D4 - Incorrect Operations: Vehicle Operation	18.49	18.49	18.49	18.49	18.49	18.49	**110.93**
D5 - Process/System Design Failure	7.38	7.38	7.38	7.38	7.38	7.38	**44.29**
D6 - Fitness for Duty Issues	0.99	0.99	0.99	0.99	0.99	0.99	**5.95**
D7 - Lack of Skills and Qualifications	0.49	0.49	0.49	0.49	0.49	0.49	**2.96**
Total	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**3,824.49**

Risk-specific information

Description of the Risk:
Edison defines the Risk for this chapter simply as "Acts performed by an SCE employee and/or contractor ("SCE worker") that lead to an adverse outcome for SCE workers or the public." (p. 245)

Edison lists the adverse potential acts as: (p 241)

- 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;
- Following incorrect processes or system designs;
- Not being fit for duty; and
- Lacking necessary skills or qualifications.

Existing Baseline Controls
SCE's Chapter 7 Control measures program consists of two "voluntary" controls[31], and two obligatory controls required by regulatory statute that the utility does not analyze or count as an expense for the purposes of its RAMP report.
For its two controls addressed in Chapter 7, SCE proposes to spend in total $15.2 million on controls for the six period 2018-2023 (Figure V-1). Curiously, within its Controls section, SCE speaks to only spending levels for past efforts in 2017.

Table pulled from p. 258

Table III-1 – Inventory of Compliance & Controls[10]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Costs ($M)	
					Capital	O&M
CM1	Safety Compliance – Standards, Programs & Policies	Not Modeled	Not Modeled	Not Modeled	$0	$11.20
CM2	Safety Compliance – Technical Training	Not Modeled	Not Modeled	Not Modeled	$0	$57.50
C1	Safety Controls	All	-	-	$0	$0.30
C2	Contractor Safety Program	All	-	-	$0	$0.16

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance

Items CM1 and CM2 address statutorily-mandated State and Federal workplace safety requirements.

[31] It is necessary to footnote this item owing to the fact that SCE's C2 control is in fact a required set of controls as explained on the following page.

C1 – Safety Controls (p. 259)
This item covers SCE elective worker-safety programs that exceed State and Federal requirements. These programs include the Safety Recognition Program, Injury Assistance Program, and Functional Movement Screening (stretching exercises).

RESULT: Results not modeled for this control addressing minor injuries: No injuries, No fatalities; No reliability costs and Minor financial costs. Drivers D2 and D3 impacted.

C2 – Contractor Safety Program (p. 259)
This control addresses SCE efforts to improve the safety of its contractors according to terms of a 2017 Settlement Agreement in D.17-06-028. SCE notes that the program affects all drivers but no outcomes or consequences. The five-component program appears to add rigor to the SCE's processes for vetting and qualifying contractors expected to perform higher-risk activities. Interestingly, although Edison acknowledges that it is obligated to perform this control, the utility chose not to include it within its CM category, which denotes mandatory and regulatory-required controls.

RESULT: No injuries, No fatalities; No reliability costs and Minor financial costs. SCE reports that all Drivers would be impacted.

MITIGATION PLAN OVERVIEW

Edison identifies seven mitigation measures, which within various combinations with existing control measures, constitute three potential mitigation plan scenarios — a preferred plan and two alternatives. Discounting those mitigations that so similar as to be near duplicates, SCE puts forward four potential mitigation measures.

Table pulled from p. 262

Table IV-1 – Inventory of Mitigations[15]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan			RAMP Implementation	
					Proposed	Alt. #1	Alt. #2	Start	End
M1a	Safety Culture Transformation – Core Program	All	-	-	x		x	2018	2021
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards	All	-	-		x		2018	2023
M2	Industrial Ergonomics	D2, D3, D5, D7	-	-	x	x	x	2018	2023
M3a	Office Ergonomics – Core Program	D3, D5, D7	-	-	x	x	x	2018	2023
M3b	Office Ergonomics – Additional Software	D3, D5, D7	-	-		x		2018	2023
M4a	Driver Safety Training – Full Training Population	D3, D4, D7	O5	S-I		x		2018	2023
M4b	Driver Safety Training – Limited Training Population	D3, D4, D7	O5	S-I			x	2018	2023

M1 M1a – Safety Culture Transformation – Core Program
This mitigation measure, included in SCE's Preferred Alternative ("the Proposed Plan"), as a safety culture improvement effort, primarily applies to SCE employees. It consists of six sub-programs, listed below in Table IV-2.
Table pulled from p. 263

Table IV-2 – Six Focus Areas of Safety Culture Transformation Program

#	Focus Area	Objective
1	Common Understanding of Safety Culture Change	Build a common understanding and vision for our future-state safety culture.
2	Leadership and Talent Management	Implement safety culture training and safety leadership assessments, and incorporate safety into the hiring process.
3	Safety Communications	Align and improve safety communications, processes, and messaging across the company.
4	Hazard Awareness and Risk Management	Provide and enhance tools to improve the ability of employees to identify hazards and make safe decisions for how to proceed.
5	Safety Data Strategy	Improve integrity and integration of safety-related data across the company to enable data-driven insights.
6	Safety Structure, Governance, and Programs	Build foundation for successful safety culture change through organizational structures, safety governance, and refinement of existing safety programs to align with our safety culture vision.

Perhaps most notable among the six sub-programs within M1a is the Safety Data Strategy (p. 266). SCE at present does not have the capacity to store and retrieve safety data from a single source, which means that disparate systems track the utility's reliability or employee safety incidents. This sub-program would "develop and implement a comprehensive safety data architecture [and] an integrated incident management system" to improve incident cause evaluations and SCE's predictive analysis, thereby allowing the utility to "increase its ability to identify major contributing factors that lead to incidents and close calls."

RESULT: No outcomes or consequences impacted (No injuries or fatalities; No reliability costs or financial costs). All drivers reported to be impacted.

M1b – Safety Culture Transformation – Expanded Training & Electronic Tailboards (p. 268)
This mitigation, a component of Alternative 1, proposes the same elements as M1a (Safety Culture Transformation – Core Program), except that a two-day, in-person safety training component would target all SCE (rather than only those assigned to the field) staff, and would exceed M1a standards by equipping SCE field supervisors with data tablets, a tool expected to increase remote use of hazard awareness tools.

RESULT: No outcomes or consequences impacted (No injuries or fatalities; No reliability costs or financial costs). All drivers reported to be impacted.

M2 – Industrial Ergonomics (p. 269)
This mitigation, included in SCE's Preferred Alterative, addresses ergonomic improvements among field workers to reduce the incidence of sprains and repetitive injuries.

RESULT: No outcomes or consequences impacted (No injuries or fatalities; No reliability costs or financial costs). Drivers D2, D3, D5, and D7 reported to be impacted.

M3a – Office Ergonomics – Core Program (p. 270)
This measure, included in SCE's Preferred Alternative, is a behavioral modification program that addresses employee interactions with office equipment. M3a builds upon M2 (Industrial Ergonomics) by delivering flexible workstations that would allow office workers the option to sit or stand at their desk, better accommodating their ergonomic needs.

RESULT: No outcomes or consequences impacted (No injuries or fatalities; No reliability costs or financial costs). Drivers D3, D5, and D7 reported to be impacted.

M3b – Office Ergonomics – Additional Software
This mitigation, included in Alternative 1, provides staff with predictive feedback on how well they manage computer keyboard keystrokes, mouse clicks, and rest breaks. Data collected informs SCE's ergonomics intervention efforts by identifying at-risk users to allow for injury prevention.

RESULT: No outcomes or consequences impacted (No injuries or fatalities; No reliability costs or financial costs). Drivers D3, D5, and D7 reported to be impacted.

<u>Proposed Mitigation Plan ("Preferred Alternative")</u>

Edison's preferred alternative, which appears to be adequate, adopts mitigation measures M1a, M2, and M3a at a six-year cost total of $78.8 million including controls, ($63.6 million exclusive of controls). Edison's preferred alternative -- its proposed plan -- would continue existing controls (albeit in radically reduced forms) The component parts that comprise SCE's preferred alternative are described in detail above in the Mitigation Overview section.

Table pulled from p. 272

Figure·V-1—·Proposed·Plan·(2018—·2023·Total·Costs·and·Risk·Reduction)¶

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.33	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.384	0.33	0.300
M1a	Safety Culture Transformation – Core Program	2018	2021	$ 13.0	$ 33.5	2.06	0.044	1.61	0.035
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.769	0.05	0.600
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.21	0.012	0.16	0.009
		Total - Proposed Plan		$ 27.6	$ 51.8	3.18	0.040	2.48	0.031

SCE characterizes its Preferred Alternative as centered on promoting a cultural shift within the organization to fundamentally alter the utility's attitudes and habits toward safety by way of implementing a safety culture transformation program. The Preferred Alternative would also include an ergonomic program for industrial and office assignments.

Edison notes that the Preferred Alternative costs $10.9M less than Alternative 1, and $1.7M less than Alternative 2. The RSE of the Preferred Alternative (0.040) is higher than Alternative 1 (0.039) and is the same as Alternative 2 (0.040) on a mean basis. SCE characterizes its Preferred Alternative as achieving a balance of reducing safety risks at prudent cost.

Alternative Mitigation Plans

Alternative Plan #1

SCE's appraisal of Alternative 1 states: "The highest cost option with the lowest RSE. Although this plan maximizes the implementation of potential mitigations that SCE could implement at this time, it does not offer a compelling value proposition. The higher cost of the plan ($10.9M more than the Proposed Plan) does not come with a commensurate risk reduction." SCE also notes Alternative 1's RSE of 0.039 is lower than the 0.040 RSE delivered by the Preferred Alternative.

Table pulled from p. 274

Table·VI-1—·Alternative·Plan·#1·(2018—·2023·Total·Costs·and·Risk·Reduction)¶

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.34	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.383	0.33	0.301
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards	2018	2023	$ 13.0	$ 41.4	2.26	0.042	1.78	0.033
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.765	0.05	0.601
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.20	0.011	0.16	0.009
M3b	Office Ergonomics – Additional Software	2018	2023	$ 0.8	$ 0.3	0.06	0.060	0.05	0.047
M4a	Driver Safety Training – Full Training Population	2018	2023	$ -	$ 1.7	0.09	0.051	0.13	0.078
		Total - Alternative Plan #1		$ 28.4	$ 61.6	3.52	0.039	2.83	0.031

Alternative Plan #2

Table pulled from p. 276

Table·VII-1—·Alternative·Plan·#2·(2018—·2023·Total·Costs·and·Risk·Reduction)¶

Alternative Plan # 2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.34	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.383	0.33	0.301
M1a	Safety Culture Transformation – Core Program	2018	2021	$ 13.0	$ 33.5	2.05	0.044	1.61	0.035
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.767	0.05	0.602
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.20	0.012	0.16	0.009
M4b	Driver Safety Training – Limited Training Population	2018	2023	$ -	$ 1.7	0.07	0.041	0.11	0.068
			Total - Alternative Plan #2	$ 27.6	$ 53.5	3.24	0.040	2.60	0.032

Alternative 2 is identical to SCE's Preferred Alternative with the exception that it includes as an additional mitigation measure the M4b (Vehicle Operator Safety Training – Limited Training Population). Edison noted a modest cost increase for Alternative 2 that comes with a commensurate risk reduction. Ultimately, SCE cited concerns over taking on too much at once and risk of institutional "change fatigue" as reasons for pursuing the somewhat more streamlined Preferred Alternative.

CONCLUSION

SED looks forward to monitoring Edison's progress as it carries out its described Safety Culture paradigm shift. In particular, SED will be interested to learn how and by how much SCE's retooled organizational values, redoubled commitment, and new leadership can fundamentally refocus the utility's priorities toward safety to lower incidence of adverse events that impact the public and SCE's workforce.

APPENDIX E – PHYSICAL SECURITY CHAPTER CRITIQUE AUTHOR: JEREMY BATTIS

Chapter 9 – Physical Security (pp.351/355 – 395 pdf)
All page references denote numbering in the pdf version

SUMMARY
SCE's chapter on Physical Security "encompasses those elements and strategies directly involved in physical protection, such as implementing perimeter walls and fencing, lighting, cameras, and conducting security patrols." (p. 355) and "analyzes incidents occurring within the perimeter of [Edison] facilities that result in theft, trespassing, workplace violence, or a coordinated attack targeting multiple substations." (p. 356) Somewhat confusingly, SCE has elected to both include and exclude certain activities whose scope appear to be in conflict with one another. For instance, within Chapter 9 scope are scofflaw activities like trespassing and homeless camping along with minor crime like metal theft. At the same time, SCE has excluded from scope what appear to be those injuries suffered by unauthorized persons on Edison property. It's not possible to confidently interpret Edison's out-of-scope disclaimer given that the utility employs vague and undefined terminology such as "public safety incidents" and "criminal activity."

SED Generated Table 9-1: Summary of Risk, Reduction, Cost, and Spending Efficiency

	A	B	C
1			
2		MARS-EV Existing Baseline annual	3.67
3		MARS-EV Proposed Plan Risk Score Reduction (annual)	1.77
4		MARS-EV Proposed Plan Risk Score Reduction (all years)	10.60
5			
6		MARS-TA Existing Baseline annual	14.16
7		MARS-TA Proposed Plan Risk Score Reduction (annual)	6.98
8		MARS-TA-Proposed Plan-Risk Score Reduction (all years)	41.88
9			
10		*RSE Units of Risk Reduced Per Million Dollars:*	
11		MARS-EV Proposed Plan Total RSE (Units/$ Millions)	0.03
12		MARS-TA Proposed Plan Total RSE (Units/$ Millions)	0.11
13			
14		*2017 Baseline Controls and Mitigations:*	
15		Recorded control expense costs	51.69
16		Recorded control capital costs	25.75
17			
18		*2018-2023 Cost in Millions of Dollars:*	
19		Mitigation plan O&M (annual average)	43.37
20		Mitigation plan capital costs (annual average)	21.23
21		Mitigation plan costs for control measures (annual avg)	28.13
22		Mitigation plan total six-year cost	387.59

Note that 2017 baseline control expenses shown in Table 9-1 include $29.9 million in expenses to comply with Federal regulations (CM controls) per Table III-1, below. Excluding these non-elective costs, 2017 baseline control costs totaled $21.8 million, compared to about $28.1 million budgeted annually beginning 2018 per Table V-1, below. SED points out this detail as Edison's proposed 2018-2023 program costs do not account for Federal regulations compliance (CM controls) costs; Edison's planned 2018-2023 CM costs are not disclosed in the RAMP chapter.

Edison proposes an approximately $387.6 million total cost, six-year mitigation plan, expected to reduce the Risk by 1.77 annual MARS units with an estimated RSE of 0.027. With Edison's annual baseline Physical Security risk estimated at 3.67 MARS units, SCE's resulting mitigated

Risk would be 1.9 annual MARS units, or a risk reduction of about 52 percent. The annual cost comes to $64.6 million per year. From the perspective of tail average, Chapter 9 mitigation plan cost-efficiency performs better with an RSE of 0.108. Essentially, it seems, for a $64.6 million annual cost, Edison avoids less than one serious injury per year. And at best, applying tail average numbers, Edison's physical security plan might avoid five injuries and one death per year. (See SED's Table 9-2, below, for estimated injuries and deaths associated with this risk chapter.)

Table pulled from p. 358

Table I-2 – Summary of Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1a	Grid Infrastructure Protection - Base			X
C1b	Grid Infrastructure Protection - Enhanced	X	X	
C2	Protection of Generation Capabilities	X	X	X
C3a	Non-electric Facilities/Protection of Major Business Functions - Base			X
C3b	Non-Electric Facilities/Protection of Major Business Functions - Enhanced	X	X	
C4	Asset Protection	X	X	X
M1a	Insider Threat Program Enhancement & Information Analysis - Base	X		X
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced		X	
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	X	X	
M3	Smart Key Program Phase 2 - Electrical Sites		X	
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites		X	
Mean (MARS)	*Cost Forecast ($ Million)*	$64.60	$71.32	$54.70
	Baseline Risk	3.67	3.67	3.67
	Risk Reduction (MRR)	1.77	2.04	1.40
	Residual Risk	1.90	1.64	2.27
	Risk Spend Efficiency (RSE)	0.027	0.029	0.026
Tail Average (MARS)	*Cost Forecast ($ Million)*	$64.60	$71.32	$54.70
	Baseline Risk	14.16	14.16	14.16
	Risk Reduction (MRR)	6.98	8.05	5.52
	Residual Risk	7.19	6.11	8.64
	Risk Spend Efficiency (RSE)	0.108	0.113	0.101

Table pulled from p. 368

Figure II-3 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Theft	53.0 %	
O2 - Trespassing	46.9 %	
O3 - Workplace Violence	0.1 %	
O4 - Coordinated Attack on Multiple Substations	0.0 %	

For Chapter 9, Edison does not provide adequate risk summary narrative or tables, with clarity suffering as a result. In this regard, the physical security chapter is less robust than other SCE RAMP chapters.

To remedy this situation somewhat, SED assembled Table 9-2, below, an injury and fatality (and other outcome) summary that shows in one place SCE data provided piecemeal in the RAMP chapter submittal. Table 9-2 indicates that Chapter 9 total risk would account for about one serious injury per year; less than one fatality per year; approximately 39.6 million Customer Minutes Interrupted; and approximately $4.4 million in financial consequences.

To promote ease of review and greater transparency, Edison should provide such an outcome table for all future RAMP and GRC risk chapters. Also, because it would be valuable as a comparison metric, going forward SCE should cite each risk's rank in terms of cost and RSE among all risk chapters within both narrative and a table.

Note that in Chapter 9 SCE does not attempt to provide data that would differentiate injuries as minor or severe. Rather, SCE includes only injuries typified as serious. Thus Table 9-2 presents only those injuries that SCE has categorized as serious.

SED Generated Table 9-2: Summary of Outcome Impacts

	A	B	C	D	E	F	G	H	I	J
1										
2			Injuries		Fatalities		Reliability	(CMI -Ms)	Financial	($millions)
3			*Mean*	*Tail Avg*	*Mean*	*Tail Avg*	*Mean*	*Tail Avg*	*Mean*	*Tail Avg*
4		O1 theft	-	-	-	-	2.00	2.50	1.50	2.10
5		O2 trespassing	-	-	-	-	-	-	0.24	0.31
6		O3 workplace violence	0.84	6.92	0.52	4.29	-	-	-	-
7		O4 coordinated attack on multiple substations	0.32	3.13	0.10	1.05	37.67	376.11	2.61	26.03
9		**sum**	**1.16**	**10.05**	**0.62**	**5.34**	**39.67**	**378.61**	**4.35**	**28.44**

Table 9-2 illustrates modeled baseline annual adverse outcomes attributable to Chapter 9 risks.

STRENGTHS
Edison demonstrates good subject matter expertise and a fundamental grasp of the organization's vulnerabilities and weak areas to be addressed. SED appreciates SCE's effort and its inventory of physical security areas that have room for improvement.

AREAS FOR IMPROVEMENT
Concerns with No Reference to SED Physical Security White Paper (2018) or Related Proceeding R.15-06-009.

The CPUC in January 2019 completed its Physical Security Proceeding, an effort initiated in 2015 and culminating in D.19-01-018. SCE's RAMP makes no mention of this rulemaking. Given that R.15-06-006 addressed non-NERC/FERC assets, namely distribution stations and control centers, SED would like to see greater granularity and more specifics regarding SCE's known and estimated risk, mitigation, and spending for transmission v. distribution grid assets.

Concerns with Plan Alternatives
As discussed below, Edison fails to provide three bona fide plan alternatives, but rather offers alternatives that are small variations on a preferred alternative. SED recommends that SCE describe two viable Risk mitigation plan alternatives in addition to a preferred alternative within all future risk chapter submittals.

Concerns with Choice of Insider Threat Mitigation Measure
Relatedly, by opting to go with the lesser version of its two identified Insider Threat mitigation options, SCE proposes to forego what appears to be an opportunity to capture more risk reduction at marginally more cost. SCE's Insider Threat Enhanced Option M1b is short on details but SED is intrigued by the prospect of Edison bolstering its in-house capacity with outside expertise, and an accelerated implementation schedule that it promises appears appropriate.

Concerns with Poor Word Choice to Describe Items Out of Scope
SCE's Chapter 9 at p. 357 (second bullet) describes actions and conditions out of scope. While it may be that Edison's intent here is to rule out injuries and deaths as a result of trespass to steal copper wire, SCE introduces an element of confusion through imprecise language.

"<u>Public safety incidents</u> resulting from criminal activity that occurs as a result of the public's unauthorized interactions with SCE's electric and or non-electric assets.
It's unclear exactly whether Edison considers injury or death in the course of copper theft to be a public safety incident, or whether there might be some resulting power outage which would be a public safety incident.

Also, a broad interpretation of SCE's disclaimer could have it disqualify a Metcalf-type (an unauthorized interaction with an electric utility asset) incident as applicable to Chapter 9.

Lastly on the subject of Metcalf, SED disputes SCE's characterization at p. 361 that the "Metcalf substation is located in a highly concentrated area and supplies electricity to Silicon Valley." The Metcalf site is situated within a secluded, more rural than urban area known as Coyote Creek.

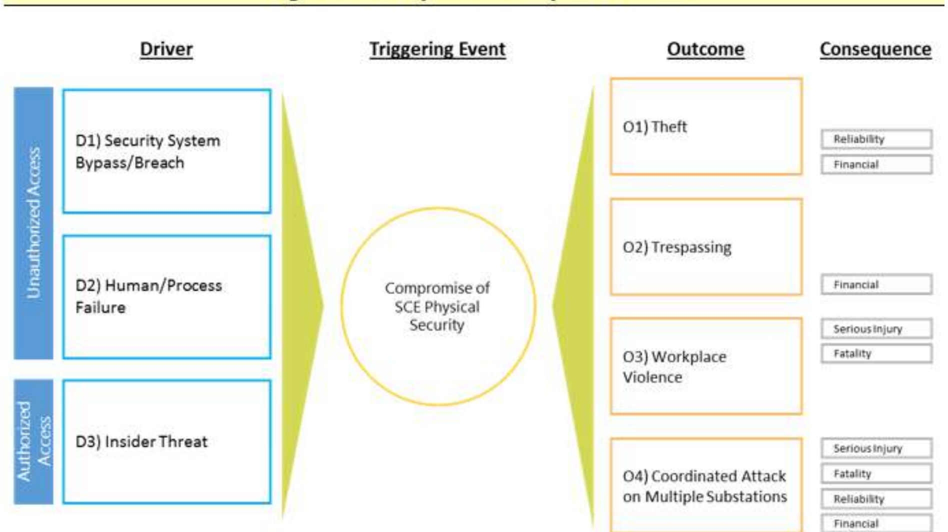
Concerns about Use of Undefined Term "Intruder"

- "Between 2015 and 2017, there were two reported safety incidents where intruders either suffered serious injury or fatality within SCE substations." (p. 362)

SCE's Chapter 9 at p. 362 provides this bullet point sentence whose meaning is unclear. Specifically, as used here, the term intruder can have multiple meanings. SCE should use a more precise term to differentiate between an attacker or a copper thief/ homeless camper. SED is unclear whether Edison's reference here references non-attacking trespassers. SCE should clarify its intent and ensure consistency with its choice to exclude from scope non-attacking trespassers (per Table I-1).

Risk Bowtie, Risk Drivers, and Triggering Events
Physical Security Chapter 9 Risk Bowtie Schematic
(Table pulled from p. 363)

Figure II-1 – Physical Security Risk Bowtie



Edison's Chapter 9 risk bowtie, shown above, on first pass seems unnatural and not intuitive. As an example, the risk Triggering Event "Compromise of SCE Physical Security" is passive and undefined, and too vague to be of much value. SCE does not make a clear and persuasive case for how its identified risk drivers, when brought to bear by a Triggering Event catalyst, would result in an identified outcome.

Drivers

SCE derives the Frequency for a Chapter 9 Triggering Event by summing the estimated annual frequencies of its three drivers D1, D2, and D3.

Table below pulled from p. 364

Figure II-2 – 2018 Projected Driver Frequency

Name	Freq	Frequency
D1 - Security System Bypass/Breach	92	
D2 - Human/Process Failure	59	
D3 - Insider Threat	1	

SED notes Edison's Driver frequency growth table, shown below. SCE explains that its assumed annualized risk Driver Frequency growth rate of seven percent is predicated somewhat on past trends. SCE applied past upward trends and applied added factors such as past success rate internationally of electrical infrastructure attacks, relative ease of locating on line information to support an attack, and the belief that the greater Los Angeles area – as a center of media and media attention – would be a location that would generate abundant headlines, a goal of most terrorist organizations.

Table below pulled from p. 367

Table II-1 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	Total
Physical Security							
Baseline	**151.32**	**191.24**	**220.42**	**252.27**	**286.86**	**324.27**	**1,426.38**
Driver							
D1 - Security System Bypass/Breach	92.14	115.08	131.96	150.32	170.20	191.65	**851.34**
D2 - Human/ Process Failure	58.50	75.35	87.55	100.93	115.52	131.35	**569.19**
D3 - Insider Threat	0.68	0.81	0.92	1.03	1.14	1.27	**5.85**
Total	**151.32**	**191.24**	**220.42**	**252.27**	**286.86**	**324.27**	**1,426.38**

Risk-specific information

Description of the Risk:

Edison defines the Risk for this chapter as "Third party breaching the security perimeter due to security system bypass/breach, human error, or process failure;" and "An insider (e.g., an SCE employee or authorized contractor) using their access or knowledge with malicious intent." (p. 355)

Existing (Baseline Mitigation) Controls

SCE's Chapter 9 Control measures program consists of two obligatory controls required by Federal regulatory statute that the utility does not analyze or count as an expense for the purposes of its RAMP report, and six elective controls, of which two pairs are variations on a theme. Therefore, SCE's controls consist of four unique control approaches.

Table below pulled from p. 374

Table III-1 – Inventory of Compliance & Controls[36]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	NERC CIP-014	Not Modeled	Not Modeled	Not Modeled	$ 26.54	$ -
CM2	NERC V6 Low BES Sites	Not Modeled	Not Modeled	Not Modeled	$ 3.38	$ -
C1a	Grid Infrastructure Protection - Base	All	All	All	$ 11.62	$ -
C1b	Grid Infrastructure Protection - Enhanced	All	All	All		
C2	Protection of Generation Capabilities	All	All	All		
C3a	Non-Electric Facilities/Protection of Major Business Functions - Base	All	All	All	$ 10.15	$ -
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	All	All	All		
C4	Asset Protection	All	All	All	$ -	$ 25.75

Items CM1 and CM2 address statutorily-mandated Federal physical security requirements.

C1 – Grid Infrastructure Protection C1 – Safety Controls (p. 376)
Grid Infrastructure Protection 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, which are prioritized by importance and vulnerability.

Control measures may include access control, alarms, perimeter protection (e.g., fencing, walls, barbed wire, etc.), and video surveillance.

SCE put forward two variations of this control:
C1a – Base Option continues existing controls, including upgrading fencing, improving lighting, updating the processes to identify facilities requiring improved monitoring by security cameras and other technology, detecting criminal activity that results in deploying uniformed security officers, and improving access management and control processes.

C1b – Enhanced Option replicates Base option C1a, but also includes improvements in managing and controlling access. These enhancements include tamper-resistant gate motors and hardware, and perimeter video analytics, and also provide for visitor/access management technology that automates visitor access and tracking, allowing SCE to retire its paper logs of visitor activities.

RESULT: SCE reports that all four Outcomes would be impacted by both controls. SCE reports that all Drivers (D1, D2, and D3) would be impacted by both controls.

C2 – Protection of Generation Capabilities (p. 377)
This existing control addresses generation facilities, and duplicates most of the security measures found in C1 Grid Infrastructure Protection control. However, C2 customizes these measures to fit an individual generation asset's characteristics and physical setting.

RESULT: SCE reports that all four Outcomes would be impacted. SCE reports that all Drivers (D1, D2, and D3) would be impacted.

C3 – Non-Electric Facilities - Protection of Major Business Functions (p. 378)
This control protects SCE's non-electric facilities, including corporate general offices, service and call centers, other structures. Security fencing and gates similar to those in C1 and C2 (Protection of Generation Capabilities) may be used to protect typical SCE structures, with corporate and business offices assigned uniformed security staff, access controls, video surveillance, and security alarms.

SCE put forward two variations of this control:
C3a – Base Option is an ongoing effort to protect SCE's assets at non-electric facilities in response to rising incidents of theft, trespassing, and workplace violence. Measures include a maintenance program and improvements to how SCE identifies and responds to threats. This control combines physical security technologies such as access controls based on corporate identification badges, video surveillance, and security alarms.

C3b – Enhanced Option includes measures identified in the Base option (C3a), but also includes visitor/access management technology that automates visitor access and tracking, allowing SCE to retire its paper logs of visitor and access activities at non-electric facilities.

RESULT: SCE reports that all four Outcomes would be impacted. SCE reports that all Drivers (D1, D2, and D3) would be impacted.

C4 – Asset Protection - O&M C2 – Protection of Generation Capabilities (p. 380)
This existing control enables SCE to: 1) properly vet SCE workers before hiring via a background investigation; 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.

RESULT: SCE reports that all four Outcomes would be impacted. SCE reports that all Drivers (D1, D2, and D3) would be impacted.

MITIGATION PLAN OVERVIEW

Edison identifies five mitigation measures, which within various combinations with existing control measures, constitute three potential mitigation plan scenarios — a preferred plan and two alternatives. Discounting those mitigations that are so similar as to be near duplicates, SCE puts forward two unique potential mitigation measures strategies.

Table below pulled from p. 382

Table IV-1 – Inventory of Mitigations

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1a	Insider Threat Program Enhancement & Information Analysis - Base	All	All	All	X		X
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced	All	All	All		X	
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	All	All	All	X	X	
M3	Smart Key Program Phase 2 - Electrical Sites	All	All	All		X	
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites	All	All	All		X	

M1 – Insider Threat Program Enhancement & Information (p. 382)
This mitigation will improve SCE's ability to identify and respond to insider threats by implementing new processes to collect and analyze data. This program, to be implemented from 2019-2023, includes: 1) Expanded background investigation capacity described in C4 (Asset Protection) to screen SCE applicants' and contractors' online presences, including social media, as requisite for advancement and hiring; and 2) Create a new internal threat intelligence, data, and analytics program to counter any insider-threat against SCE workers, the Company, and/or assets.

SCE put forward two variations of this mitigation measure:
M1a – Base Option This mitigation implements an enterprise-wide program to protect against insider threats that could lead to workplace violence, intellectual property theft, compromise of grid control, exposure of critical electrical infrastructure information, and physical-cyber joint vulnerabilities. Additional aspects include development of a new training program for all employees to proactively identify insider threats and improve employee awareness of security protocols

M1b – This enhanced option supports an expanded and accelerated version of the M1a program. This mitigation option would primarily utilize external experts to analyze unusual behaviors or patterns that may indicate risks, which should improve identification and response times.

RESULT: SCE reports that all four Outcomes would be impacted. SCE reports that all Drivers (D1, D2, and D3) would be impacted.

M2, M3, M4 – Smart Key Program: Phases 1, 2, and 3 (p. 384)
Mitigations M2, M3, and M4 implement Smart Key technology to different facilities. Smart Key technology replaces conventional locks and keys. Smart Keys include both mechanical and electronic features, and integrate with SCE's access control system. Smart Keys allow SCE to customize access and entry to grant varying levels of authorization based on workforce assignment, seniority, and assigned clearance level. Another benefit of Smart Keys is a built-in expiration date, and the ability to deactivate -- invaluable should a key be reported as lost or stolen. Smart Keys also provide a time-stamped record of every use.

SCE considered implementing Smart Keys through three phases over the RAMP period:

- Phase 1 (M2): Approximately 130 of SCE's most critical facilities.[32]
- Phase 2 (M3): Approximately 800 of the remaining SCE electrical facilities are captured by this phase.
- Phase 3 (M4): Approximately 300 of SCE's non-electric facilities

RESULT: SCE reports that all four Outcomes would be impacted. SCE reports that all Drivers (D1, D2, and D3) would be impacted.

<u>Proposed Mitigation Plan ("Preferred Alternative")</u> (p. 386)
Edison's preferred alternative adopts mitigation measures M1a, M2, and M3a at a six-year cost total of $78.8 million including controls, ($63.6 million exclusive of controls). Edison's preferred alternative -- its proposed plan -- would continue existing controls. The component parts that comprise SCE's preferred alternative are described in detail above in the Mitigation Overview section.

[32] Facility criticality is determined by internal business impact analyses that consider regulatory requirements, critical business functions, and impact to the bulk electric system.

Table pulled from p. 386

Table V-1 – Proposed Plan (2018-2023 Totals)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$ 144.66	$ 0.79	2.10	0.014	8.25	0.057
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.66	0.071	6.53	0.280
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	2018	2023	$ 74.02	$ 0.94	2.14	0.029	8.39	0.112
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	1.88	0.014	7.39	0.056
M1a	Insider Threat Program Enhancement & Information Analysis - Base	2019	2023	$ -	$ 1.47	1.17	0.795	4.75	3.227
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	2019	2022	$ 9.04	$ 0.23	1.65	0.178	6.55	0.707
			Total - Proposed Plan	**$ 260.24**	**$ 127.35**	**10.60**	**0.027**	**41.86**	**0.108**

SCE characterizes its Preferred Alternative as the option that "best positions SCE to address both the low-probability, high-impact physical attack risks, and the more frequent, lower-impact physical security risk events."

Edison notes that the Preferred Alternative is the midrange approach, costing $40.35 million less than Alternative 1, and $59.4 million more than Alternative 2 over six years. The RSE of the Preferred Alternative (0.027) is lower than Alternative 1 (0.029), and is higher than Alternative 2 (0.026) on a mean basis. SCE characterizes its Preferred Alternative as achieving a balance of reducing safety risks at prudent cost.

SED notes that on an annual basis, the Preferred Alternative costs $6.7 million per year less than Alternative 1, and $9.9 million more than Alternative 2.

__**Alternative Mitigation Plans**__

Alternative Plan 1

SCE's appraisal of Alternative 1 states: "Similar to the Proposed Plan, [it] continues to deploy SCE's layered physical security approach. This plan then adds significant incremental resources to protect against Insider Threats and accelerates deploying Smart Keys and visitor access controls."

SCE expresses some reservation about Alternative 1's prospects for meeting its ambitious but necessary project schedule given the its physical characteristics (rapid and widespread conversion of locks; issuance of new key cards) but its virtual (programming and testing; orientation and training of staff). SCE ultimately decides against favoring Alternative 1, in part because of the risks inherent in its rapid pace and broad scope.

Table below pulled from p. 389

Table-VI-1—Alternative-Plan-#1-(2018-2023-Totals)¶

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$ 144.66	$ 0.79	1.92	0.013	7.55	0.052
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.51	0.065	5.97	0.256
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	2018	2023	$ 74.02	$ 0.94	1.95	0.026	7.68	0.102
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	1.71	0.013	6.74	0.051
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced	2019	2023	$ 0.70	$ 1.49	1.42	0.649	5.72	2.614
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	2019	2022	$ 9.04	$ 0.23	1.50	0.162	5.97	0.645
M3	Smart Key Program Phase 2 - Electrical Sites	2019	2023	$ 30.97	$ 0.11	1.16	0.037	4.70	0.151
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites	2022	2023	$ 8.43	$ 0.13	1.04	0.121	3.98	0.465
		Total - Alternative Plan #1		$300.34	$127.60	12.21	0.029	48.31	0.113

Edison's Alternative 1 costs $40.35 million more than its Preferred Alternative, with an RSE that is marginally higher (0.029 for Alternative 1 v. 0.027 for the Preferred Alternative.
SED notes that Alternative 1 is the only mitigation plan to feature the bolstered insider threat mitigation measure M1b.

Alternative Plan 2

Table below pulled from p. 391

Table-VII-1—Alternative-Plan-2-(2018-2023-Totals)¶

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1a	Grid Infrastructure Protection - Base	2018	2023	$ 109.67	$ 0.60	1.62	0.015	6.34	0.057
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.84	0.079	7.24	0.310
C3a	Non-Electric Facilities/Protection of Major Business Functions - Base	2018	2023	$ 59.37	$ 0.60	1.56	0.026	6.08	0.101
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	2.08	0.016	8.22	0.062
M1a	Insider Threat Program Enhancement & Information Analysis - Base	2019	2023	$ -	$ 1.47	1.29	0.876	5.26	3.573
		Total - Alternative #2		$201.57	$126.60	8.39	0.026	33.14	0.101

Alternative 2 offers a significantly paired down version of SCE's Preferred Alternative, with the M2 smart keys measure eliminated, and lighter versions of C1 Grid Infrastructure Protection and C3 Non-Electric Facilities Protection; the remaining two mitigations C2 and C4 are identical to the Preferred Alternative.

Edison's Alternative 2 costs $59.4 million less than its Preferred Alternative, with an RSE of 2 (0.026) v. the Preferred Alternative's 0.027 value.

CONCLUSION

SCE puts forward a plan that achieves, in its words, measurable risk reduction at moderate cost and with a likely chance of project success.

As mentioned above, in its Concerns with Choice of Insider Threat Mitigation Measure, it appears that by opting to embrace the lesser version of the two identified Insider Threat mitigation options, SCE may be missing an opportunity. SCE's Insider Threat Enhanced Option M1b is short on details but SED is intrigued by the prospect of Edison bolstering its in-house capacity with outside expertise, and SED supports the described accelerated implementation schedule that accompanies the proposal.

SED would like to have seen M1b as an option within more than of Edison's three alternatives. SED notes that the annual additional cost of running M1b over its lesser counterpart is a mere $120,000 per year. This small amount of additional spending would seem to be a prudent investment given SCE's recent history of workplace violence.

APPENDIX F – CLIMATE CHANGE CRITIQUE AUTHOR: JEREMY BATTIS

Chapter 12 – Climate Change (pp.497/501 - 545 pdf)
All page references denote the pdf version

SUMMARY

SCE's chapter on Climate Change addresses activities through 2023, and at more than 50 pages long. A separate chapter for Climate Change activities thru 2050 appears as an appendix; it is not addressed within the scope of this SED review report. Edison does a relatively good job of explaining the Risk and establishing its parameters; providing background to describe all that the IOU has been doing in recent years to address the issue; articulating how an anticipated "new normal" of extreme weather events are expected to impact the utility's operations and assets; and sharing some of the utility's vision for how it intends to adapt to the new normal.

Table pulled from p. 508

Table I-2 – Summary Results: Annual Average Over 2018 – 2023 Time Period

Inventory of Controls & Mitigations			Mitigation Plan		
	ID	Name	Proposed	Alternative #1	Alternative #2
	C1	Emergency Management	x	x	x
	C2	Fire Management Program	x	x	x
	C3	Climate Adaptation Community Grants*	x	x	x
	M1	Climate Adaptation & Severe Weather Program	x	x	x
	M2a	Situational Awareness, Monitoring & Analytics (Optimal)	x	x	
	M2b	Situational Awareness, Monitoring & Analytics (Max)			x
	M3	Distribution System Stress Reduction Program		x	
Mean (MARS)		*Cost Forecast ($ Million)*	$14	$18	$20
		Baseline Risk	4.53	4.53	4.53
		Risk Reduction (MRR)	1.06	1.06	1.10
		Remaining Risk	3.47	3.46	3.42
		Risk Spend Efficiency (RSE)	0.08	0.06	0.05
Tail Average (MARS)		*Cost Forecast ($ Million)*	$14	$18	$20
		Baseline Risk (MARS)	14.57	14.57	14.57
		Risk Reduction (MARS)	3.03	3.05	3.23
		Remaining Risk	11.54	11.52	11.33
		Risk Spend Efficiency (RSE)	0.22	0.17	0.16

CM: Compliance (Not shown in this chart, but addressed in Section III; this is an activity required by law, regulation, etc. As discussed in Chapter I - RAMP Overview, SCE does not model compliance activities in this report, and as such, excludes these activities from this table.)

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does model controls in this report.)

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE does model mitigations in this report.)

MARS: Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk consequences from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR: Mitigation Risk Reduction. This is the reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE: Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

**C3 is not modeled or included in the costs for this table.*

The baseline for the Climate Change risk on an annualized, unmitigated basis, comes to less than two serious injuries per year (1.63); less than one fatality per year (0.20); approximately 97 million Customer Minutes Interrupted; and approximately $157 million in financial consequences (p. 504). Edison proposes an $83.3 million, six-year mitigation plan, expected to reduce the Risk by 6.32 MARS units with an estimated RSE of 0.08.

With Edison's annual baseline Climate Change risk estimated at 4.53 MARS units, SCE's resulting mitigated Risk would be 1.06 annual MARS units, or a risk reduction of less than 25 percent. The annual cost comes to $83.2 million year. From the perspective of tail average, Chapter 12 mitigation plan cost-efficiency performs better with an RSE of 0.22. Essentially, it seems, for a

$13.9 million annual cost, Edison avoids less than one serious injury per year. And at best, applying tail average numbers, Edison's proposed plan might avoid one injury per year. (See SED's Table 12-2, below, for estimated injuries and deaths associated with this risk chapter.)

For Chapter 12, Edison does not provide adequate risk summary narrative or tables, with clarity suffering as a result. In an attempt to remedy this situation, SED assembled Table 12-1 below.

SED Generated Table 12-1: Summary of Risk, Reduction, Cost, and Spending Efficiency

	B	C
2	MARS-EV Existing Baseline annual	4.53
3	MARS-EV Proposed Plan Risk Score Reduction (annual)	1.06
4	MARS-EV Proposed Plan Risk Score Reduction (all years)	6.36
6	MARS-TA Existing Baseline annual	14.57
7	MARS-TA Proposed Plan Risk Score Reduction (annual)	3.03
8	MARS-TA-Proposed Plan-Risk Score Reduction (all years)	18.18
10	*RSE Units of Risk Reduced Per Million Dollars:*	
11	MARS-EV Proposed Plan Total RSE (Units/$ Millions)	0.08
12	MARS-TA Proposed Plan Total RSE (Units/$ Millions)	0.22
14	*2017 Baseline Controls and Mitigations:*	
15	Recorded control expense costs	4.70
16	Recorded control capital costs	-
18	*2018-2023 Cost in Millions of Dollars:*	
19	Mitigation plan O&M (annual average)	9.40
20	Mitigation plan capital costs (annual average)	4.47
21	Mitigation plan costs for control measures (annual avg)	4.33
22	Mitigation plan total six-year cost	83.20

Note that 2017 baseline control expenses shown in Table 12-1 totaled $4.7 million, compared to about $4.3 million budgeted annually beginning 2018 per Table V-1, below.

Table 12-2, below, is an injury and fatality (and other outcome) summary that shows in one place SCE data provided piecemeal in the RAMP chapter submittal. Table 12-2 indicates that Chapter 12 total risk would account for less than two serious injuries per year; less than one fatality per year; approximately 97 million Customer Minutes Interrupted; and approximately $156.5 million in financial consequences.

To promote ease of review and greater transparency, Edison should provide such an outcome table for all future RAMP and GRC risk chapters. Also, because it would be valuable as a comparison metric, going forward SCE should cite each risk's rank in terms of cost and RSE among all risk chapters within both narrative and a table.

Note that in Chapter 12 SCE does not attempt to provide data that would differentiate injuries as minor or severe. Rather, SCE includes only injuries typified as serious. Thus Table 12-2 presents only those injuries that SCE has categorized as serious.

SED Generated Table 12-2: Summary of Outcome Impacts

	Injuries		Fatalities		Reliability	(CMI -Ms	Financial	($millions
	Mean	*Tail Avg*	*Mean*	*Tail Avg*	*Mean*	*Tail Avg*	*Mean*	*Tail Avg*
O1A Major Weather	0.97	3.21	0.12	1.08	28.46	61.12	98.57	211.71
O1B Catastophic Weath	0.67	3.65	0.08	0.79	68.51	399.96	10.36	60.48
O2A Higher Energy Procurement Costs	-	-	-	-	-	-	29.91	78.84
O2B Higher Energy Procurement Cost	-	-	-	-	-	-	17.68	141.13
sum	**1.64**	**6.86**	**0.2**	**1.87**	**96.963**	**461.08**	**156.52**	**492.16**

Chapter 12 falls short in critical areas. The Climate Chapter's major deficiencies include:

- Inadequate and unrealistic plan alternative proposals;
- A flawed bowtie analysis that confuses triggering events for drivers; and
- Insufficient explanation and justification for why certain programs and mitigations fall within the Climate chapter rather the Wildfire chapter.

Concerns with Plan Alternatives

SCE's offers two alternative proposals that are not viable, and therefore are not quality plan alternatives. Each is unrealistic in that required methodology has not yet been completed, or deployment of proposed hardware counts would be a clear case of redundancy and irresponsible spending. Thus, Edison fails to provide three bona fide plan alternatives, but rather offers alternatives that are small variations on a preferred alternative. This is a major miss in that the chapter does not meet basic expectations and requirements for a RAMP risk assessment. SCE is expected, within any future Climate Change risk chapter submittal, to describe two viable Risk mitigation plan alternatives in addition to a preferred alternative.

Concerns with Bowtie Analysis

A second major flaw with the Climate chapter is its flawed bowtie analysis, which differs from the superior approach employed within the Wildfire chapter. SED's concerns are extensive and touch on SCE's choice of drivers, triggering events, outcomes, and consequences, all of which are detailed below in the sections that fall under the header "Areas for Improvement."

Concerns with Relation between Climate Chapter and Wildfire Chapter

A third big flaw with the chapter is that it lacks sufficient explanation and justification for why SCE chose to include certain programs and mitigations within the Climate chapter rather the Wildfire chapter (e.g., C-2 Fire Management Program).

Edison's choice of how it assigned responsibilities to each chapter at times appears arbitrary and suggests that SCE should improve aligning the two chapters. Overlap between the two chapters goes beyond proposed Wildfire controls and mitigation measures receiving mention in the Climate Change chapter and vice versa. In at least one case the same mitigation measure is proposed and counted in both chapters –- with different costs and risk reduction values. (For additional analysis, see below the discussion within the section Overlap with Other Chapters.)

Additional Areas of Concern within Climate Chapter

The beginning of Chapter 12 helpfully discloses limits for what is and what is not within scope (p. 502). SCE makes the choice to forego including within the chapter actions that the company can take to reduce its carbon footprint. SED recommends that this be included in future RAMP reports and for its 2021 GRC application.

Thus, one understands that the chapter will not cover curtailment of the causes of climate change (i.e., proactive; GHG reduction solutions via behavioral and other strategies), but rather will provide a response to the effects of climate change (i.e., reactive; improving resilience via capital improvements, technology, and expertise). For its next iteration of the chapter, SCE may wish to consider additional voluntary and proactive Climate Change control measures to build its internal capacity to reduce the Edison organization's carbon footprint. Examples might include new vehicle fleet goals to transition to non-carbon-emitting trucks and passenger cars, energy reduction goals for its corporate buildings, corporate campus greening and carbon sequestration efforts, and a program of carbon offsets for GHGs incurred by SCE staff in the course of jet air travel.

SED requests that Edison's next iteration of its RAMP effort improve the Climate Change risk summary by providing a discrete chapter for each of two broad climate change goals: curtailing its causes and responding to its effects. A summary of SCE programs to provide aid to disadvantaged communities while reducing risk might be summarized within a third chapter addressing social justice.

In the pursuit of improved organization and clarity, SCE should for future RAMP submittals:

- Work to avoid conflict and duplication between chapters and clearly speak to why it chose to locate a mitigation or control within a given chapter when the reason is not obvious.
- Provide a set of overarching RAMP document summary tables that rank and score risks by mean MARS, tail average MARS, cost, risk reduction and risk-spend efficiency.
- At the top of each RAMP chapter, provide a Risk stats summary that clearly indicates baseline values for risk in injuries, deaths, monetary costs, and minutes of interruption; and mitigated values for mean MARS, tail average MARS, cost, risk reduction and risk-spend efficiency, and any other key assessment factor.

- Provide an overarching RAMP organizational Table that clearly presents the full list of chapters, mitigations, controls, and subprograms and how and where they are linked, related, or overlap.
- Include a focused organizational table at the Chapter level that discloses and explains how other chapters overlap with the subject chapter. If there is no overlap, Edison should provide a statement to this effect in lieu of the table.
- Provide an overarching RAMP organizational Venn Diagram that clearly presents the full list of chapters, mitigations, controls, and subprograms and how and where they are linked, related, or overlap.
- Include a focused RAMP organizational Venn Diagram at the Chapter level that discloses and explains how other chapters overlap with the subject chapter. If there is no overlap, Edison should provide a statement to this effect in lieu of the diagram.
- In its electronic documents RAMP filings, provide original Word document and pdf versions with hyperlinks that allow for reviewer to toggle between related chapters and mitigations/controls that may overlap.
- Employ an improved numbering methodology for tables and pictorials such that the first part of the number references the chapter followed by a dash and then a picture number. In the examples of SCE's risk bowtie above, this system would avoid the Chapter 10 and Chapter 12 bowties both being labeled Figure 11-1.

STRENGTHS

Edison demonstrates subject matter knowledge that clearly establishes that the utility has studied the subject of Climate Change, has talented minds addressing the issue, and is a leader among those U.S. electric utilities working to advance solutions to new challenges brought about by new extreme environmental conditions.

AREAS FOR IMPROVEMENT

Edison clearly appears to have a preferred plan in mind. Unfortunately, it's not evident that Edison arrived at its preferred alternative after thoughtful deliberation that allowed for the best proposal to rise to the top. Rather, it appears that SCE, in drafting its chapter, did not undertake adequate development of two plan alternatives, as both are small variations on the preferred alternative, and neither are reasonably viable (one is predicated on nascent technology; the second is known to be grossly redundant in scale). Thus, Edison is encouraged to devise two risk mitigation plan alternatives that are responsible and viable approaches that would effectively reduce risk consequences.
SCE had identified many other deficiencies within Chapter 12 that are discussed throughout the body of this staff review critique.

Analysis of Chapter Specifics

SCE's Wildfire and Climate Change chapters are closely entwined. This is not so surprising as the two share common attributes. But Edison has not given sufficient attention to its organization and writing quality to avoid unnecessary entanglements, redundancy, confusing cross-references, and inconsistent accounts in descriptions and cost and risk reduction value assignments.

The following is a summary of areas where the two chapters are related, with any problem areas identified.

Climate Chapter 12's M2a – Situational Awareness, Monitoring & Analytics (Optimal) appears to have much in common with the Fire Chapter's M7 – Enhanced Situational Awareness mitigation measure. SCE needs to reconcile and explain the two programs, and provide appropriate support and verification (including any discrepancy in cost or assigned risk reduction values) to enable SED understanding of the two and how they are related or identical. As submitted, SCE has not adequately explained why it chose to have the mitigation included within both chapters. Note that the two have similar but distinct cost and risk reduction values: M7 – Enhanced Situational Awareness at $57.0m cost (p. 444) | Overall: MRR = 0.84; RSE = 0.0148 |Compare to Climate Chapter's M2A at $54.8m cost (p. 538) | Overall: MRR = 2.25; RSE = 0.04.

Chapter 12's M3 – Distribution System Stress Reduction Program appears to be a capital improvement element dependent on a related modeling capacity item within the Fire Chapter's M7 – Enhanced Situational Awareness, 3. Predictive Accuracy for Infrastructure Replacement Programs. From the Fire Chapter: "SCE has been working to develop predictive analytics techniques for a wide variety of assets, including transformers, switches, cable, and overhead circuitry" (p. 495). In the Climate Chapter, SCE characterizes its prowess as at the "still conceptual" level, but optimistic that its capacity will grow to allow it sometime in the future to begin "replacing overloaded or deteriorated equipment" (p. 536). At p. 540 SCE states, "This mitigation is still at the conceptual design phase."

SCE should reconcile characterizations within the two chapters about the prospects for and readiness of its aging-asset modeling and identification program ambitions so that it is clear where SCE's technology and capacity stand. SCE should confirm SED's understanding that Chapter 12's related mitigation would be a future capital item that awaits and relies on modeling methodology being developed as part of Chapter 10 efforts.
Chapter 12's M3 – Distribution System Stress Reduction Program is implicated by another program component within the Fire Chapter's M7 – Enhanced Situational Awareness: "SCE will implement an Asset Reliability and Risk Analytics program to build capabilities in predicting an asset's overall wildfire-related risk and prioritize work, repairs, and/or replacement(s) to minimize potential wildfire ignitions" (p. 439). Thus, within the Fire Chapter's M7, SCE has described two programs that appear to serve the same purpose but with different names

Predictive Accuracy for Infrastructure Replacement Programs (p. 495) and Asset Reliability and Risk Analytics program (p. 439).

Wildfire chapter controls and mitigations that receive mention in the Climate chapter are CM1–Vegetation Management, C2–Ester Fluid Overhead Distribution Transformer, M5– Expanded Vegetation Management, and M9–Fire Resistant Poles, all of which appear to be unproblematic.

The problem addressed by the Fire Chapter's C2 control is of particular interest and merit and is thus highlighted here. C2 – Ester Fluid (FR3) Overhead Distribution Transformer "This control will replace existing overhead distribution transformers (which are primarily filled with mineral oil) with overhead distribution transformers filled with ester fluid. Envirotemp FR3 Fluid, or ester fluid, is a derivative of renewable vegetable oil, and has a higher flash point rating than mineral oil. This decreases the likelihood that the fluid and/or fluid vapors will ignite and stay lit during a catastrophic event. This in turn reduces the chance of igniting surrounding brush and/or other flammable material surrounding the pole and transformer.

"Also, distribution transformers that are filled with ester fluid can operate at higher temperatures than mineral oil-filled distribution transformers, and still have the same life as the mineral oil-filled transformer. This increases the transformer kVA capacity. This added kVA capacity will prolong the life of the transformer's internal insulation system and improve summer heat storm performance." (p. 425)

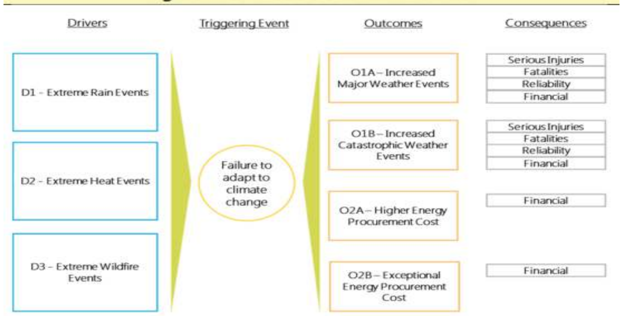
Edison, within the Fire chapter, skillfully explains the problems distribution transformers encounter when operating under prolonged periods of excessive heat. From its discussion of the driver D2g – Equipment/Facility Failure:

"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 cause a fire." (p. 415)

Risk Drivers, Triggering Events, and Risk Bowtie Schematic

Climate Change Chapter 12 Risk Bowtie Schematic
(Table below pulled from p. 511)

Figure II-1 – 2018-2023 Risk Bowtie



Problematic Drivers: SCE Confuses Triggering Events for Drivers

Edison's Chapter 12 risk bowtie, pictured above, is conspicuous in that SCE has opted to treat as drivers actions such as extreme weather that might traditionally be considered triggering events. Although intuitive, it bears clarifying that factors such as intense wind, rain, or heat place intense stress on otherwise adequate utility assets, pushing impacted hardware to their breaking point, which results in failure, and in turn, some negative outcome and consequence. Perhaps less intuitive, but quite literally, new extreme climate conditions are serving to compromise certain electric grid hardware traditionally regarded as adequate assets such that now they are more accurately categorized as vulnerable assets.

Adding to the perception that SCE's bowtie is off kilter, the utility appears to concede that extreme weather and fire events are in fact trigger events within Figure 11-3 below, which derives annual triggering event frequency by tallying occurrences of rain, heat, and wildfire events.

Table pulled from p. 517

Figure II-3 – Triggering Event Frequency Composition

Risk	2018	2019	2020	2021	2022	2023	Total
CMC							
Baseline	**10.72**	**10.58**	**10.44**	**10.29**	**10.15**	**10.01**	**62.19**
Driver							
D1 - Extreme Rain Events	5.31	5.14	4.98	4.81	4.65	4.48	**29.37**
D2 - Extreme Heat Events	4.20	4.22	4.24	4.26	4.28	4.30	**25.50**
D3 - Extreme Wildfire Events	1.21	1.21	1.22	1.22	1.23	1.23	**7.32**

Lastly, SCE's characterization of wildfires as a monolithic driver seems overly simplistic. Given that California's most destructive wildfires in recent years have been linked to human activity – with more than one event attributed to electric utility equipment – SCE's characterization of Extreme Wildfire Events as a single catch-all driver seems out of touch.

Problematic Triggering Events: SCE Tip-toes Around Its Definition

Because SCE doesn't immediately make clear what is meant by its triggering event title "Failure to adapt to climate change," a first read raises questions as to whether Failure is supposed to refer to a hypothetical Failure on Edison's part, Society's Failure, or both. Several pages in, at 517, SCE provides its only definition: "The triggering event, 'failure to adapt to climate change' reflects the notion that SCE must adapt and thoughtfully decide when identifying mitigations specifically designed to deal with the diverse impacts that climate change will create for our business."

This sentence offers little more than nailing down that the triggering event covers actions/inactions by the utility itself. In other words, SCE's triggering event definition offers little more than establishing that any organizational climate adaptation Failure would reside with Edison.

The triggering event definition as submitted is erroneous inasmuch as a triggering event cannot properly be a notion. Similarly, "adapt and thoughtfully decide" is overly ambiguous and vague. Moreover, "identifying mitigations" –- what appears to be the core of SCE's definition -– is not at all a proper triggering event. A mitigation is just that – something that lessens the likelihood of an outcome and/or the severity of a consequence. "Identifying mitigations" alone won't get Edison very far. To guard its business operations against the effects of climate change, SCE will need to commit to implementing appropriate mitigations on a scale and timeline that sets it on a course for success.

Problematic SCE Bowtie

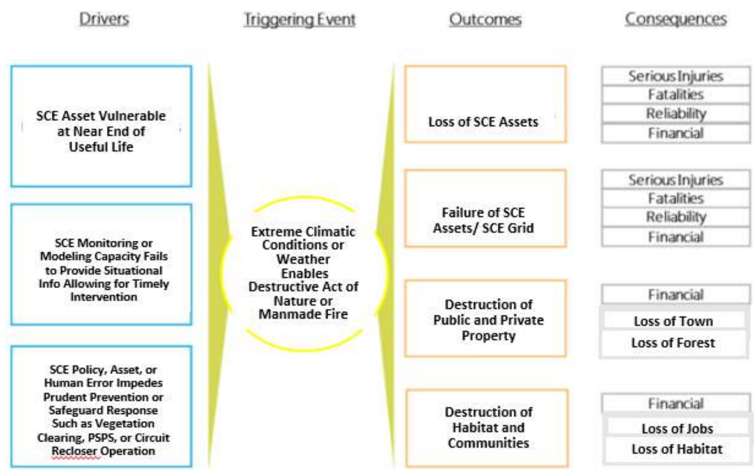
A different starting point from which to approach the Risk Bowtie analysis would be to accept the premise that certain new serious vulnerabilities have to do with SCE assets increasingly encountering new extreme operating conditions. The change has been brought about by new climate conditions that are now recognized as straining existing Edison assets. This represents something of a paradigm shift, given that in past decades – indeed for all of SCE's existence – the utility has been able to count on transformer assets that performed reliably well under certain prescribed parameters. Now, those assets' necessary operating parameters have shifted to require higher tolerance, and Edison finds itself having to respond.

Such a situation warrants a hard look at how swiftly and practically SCE can move to replace its extreme-weather-vulnerable assets to bring about upgrades that can provide assurance of performance reliability.

All of this ties back to the bowtie schematic by recognizing that a given extreme weather or fire event is only a catalyst that causes a negative outcome when its impact is brought to bear on a vulnerable asset. Accordingly, a triggering event such as extreme weather or fire would cause an incident only in the event that additional stress placed on a vulnerable asset results in failure. The advantage of setting these assumptions as the framework for the bowtie schematic is that doing so allows for designated risk drivers to be effectively managed (i.e., asset management). Likewise, the center of the bowtie schematic becomes triggering events whose scope are clearer (i.e., extreme wind, extreme rain, and extreme wildfire events). Put differently, an awkward trait of SCE's Chapter 12 bowtie is that designating extreme weather and fire as drivers results in having to combat drivers that are both unpredictable and uncontrollable.

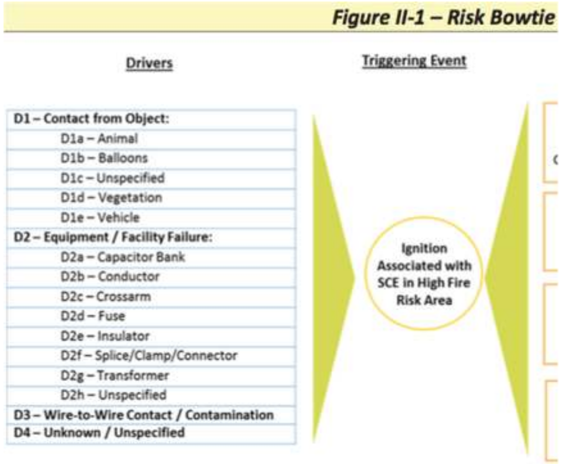
At the end point of this line of reasoning, an alternative "bow-tie" schematic might resemble the one shown in the diagram below, which more closely resembles the Edison Wildfire bowtie, and which correctly designates weather and wildfire as triggering events, rather than assigning them as drivers.

SED-Modified Climate Change Chapter 12 Risk Bowtie Schematic



In comparing the SED-modified Bowtie above to SCE's Wildfire Risk Chapter 10 Bowtie schematic below, one can see that both correctly have included within the drivers category those items related to asset failure.

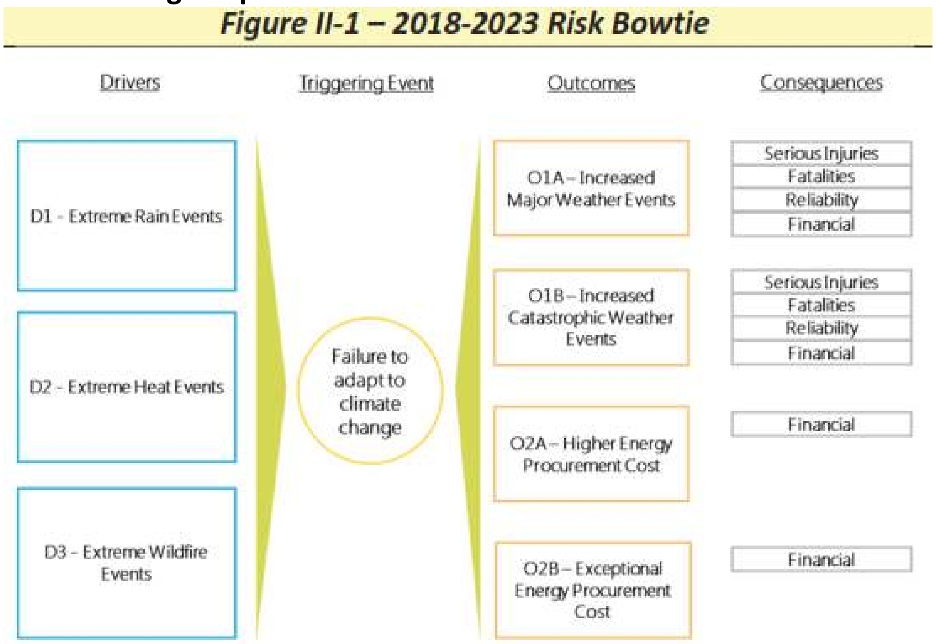
Wildfire Risk Chapter 10 Bowtie Schematic (Table below pulled from p. 408)



As discussed above, SED holds that Edison's choice to frame the Chapter 12 risk drivers as random weather events and acts of nature is simplistic; possibly misguided. A better approach would be for SCE to begin from a point that recognizes its own acknowledgment that some, if not much, of its existing grid assets are designed to operate within parameters (such as maximum temperature) that the utility can no longer reliably count on. Given that SED views SCE's designated risk drivers as incorrect, the following discussion offers guidance for how Edison might reconcile its risk bowtie schematic.

Within its RAMP, Chapters 10 and 12, Edison cites the example of circuits and transformers that rely on internal coolants whose maximum prescribed operating temperatures may be exceeded on unusually hot days, and which also are expected to have extended cooling periods that may not materialize on nights where temperatures remain well elevated. As examples of potential solutions, Edison cites changing out legacy hardware with gear that incorporates emerging technology, and preemptively replacing hardware before the end of its useful life, but prior to failure. As with responsibly clearing combustible brush and vegetation, such steps are preventative and demonstrate that SCE is adapting to new conditions to reduce risk.
Thus, SCE's bowtie diagram should be revised to include items such as "Failure to Upgrade Hardware for Extended High-heat Periods Operation," "Failure to Replace Aging Hardware Prior to Failure," and "Failure to Clear Vegetation" as risk drivers in lieu of weather and fire events; and moving weather and fire events to the center of the bowtie to replace the vague and somewhat benign-sounding "Failure to respond to climate change" as triggering events.

SCE's Existing Chapter 12 Risk Bowtie



Potential Outcomes and Consequences

An additional problem area within the SCE Chapter 12 bowtie is that in reading it as a flowchart, one has the feeling of having engaged in a circular reasoning exercise. One begins with Extreme Weather Events as inputs (Drivers) and ends with Increased Major/Catastrophic Weather Events as outputs (Outcomes).

This problem of employing similar labels for drivers and outcomes is made worse by unfamiliar terminology that SCE introduces but does not adequately define. Specifically, some pages into its Outcomes discussion Edison attempts to sort out distinctions between Extreme, Major, and Catastrophic Weather Events but is unsuccessful at eliminating reviewer confusion. SCE seems to rank Outcome 1A, Major as being less severe than Outcome 1B, Catastrophic. However, SCE goes on to describe Outcome 1A, Major as significant outage days, where SCE declares a "storm" or restoration event based on damage that may be widespread or extensive enough to require territory-wide coordination. It also remains unclear if extreme weather is a blanket term intended to cover both major and catastrophic events. Edison should pin down its terminology and write with greater precision and clarity.

Other problem areas within SCE's Chapter 12 Outcomes include Edison's inclusion of two cost-category Outcomes tied to procurement, but no mention of injuries, deaths, loss of service, or loss of property before introducing Consequences, and then these important considerations are addressed only at a very conceptual level.

Edison may wish to try to speak to any costs resulting from loss of property and resources (its own and others'), as well as financial costs that could result from legal entanglements or Commission sanctions and penalties. Absent any such discussion, SCE might at least provide a disclaimer explaining why such items may be out of scope and whether Edison has intends to include any them within a future RAMP work product.

Risk-specific information

Description of the Risk: The risk entails extreme weather and fire events compromising SCE critical assets such that safety, reliability, and affordability are threatened. The specific risk instigators, hazards, and end results remain unresolved as SED finds certain key portions of Edison's Chapter 12 to be deficient and unpersuasive.

When ten triggering events per year are applied to the model, Edison derives the following projected to occur on an annual basis:

- Six instances of major storm events resulting in 0.97 serious injuries, 0.12 fatalities, over 28 million CMI, and over $98 million in financial harm, on a mean basis;
- Less than one instance of a catastrophic storm — estimate of annual impacts is 0.67 serious injuries, 0.08 fatalities, over 68.5 million CMI, and over $10.3 million in financial harm, on a mean basis;
- Approximately three instances of increased energy procurement costs due to heat events — the estimate of annual impacts is nearly $30 million in financial harm, on a mean basis; and
- Less than one instance of exceptionally high energy procurement costs due to heat events and other compounding factors — the estimate of annual impacts is over $17 million in financial harm, on a mean basis.

Potential Consequence:

As with other certain fundamentals surrounding SCE's Chapter 12 Risk, SED has identified concerns surrounding its Risk Outcomes and Consequences, all of which are discussed above in detail.

Existing (Baseline Mitigation) Controls

Edison's existing Climate Change controls include its Emergency Management efforts ($3.7 million annually), a Fire Management Program ($0.5 million annually), and Climate Adaptation & Resiliency Community Grants ($0.5 million annually).
Edison's three existing controls are diverse and appear to ensure internal readiness and an ability to quickly activate measures for incidents and mutual assistance requests or responses with partners. Edison's priority on early detection of wildfires, and its support of messaging to

educate communities on climate change impacts and encourage grassroots organizing and awareness appear to be appropriate strategies.
Table below pulled from p. 524

Table III-1 – Inventory of Compliance & Controls[51]

Controls		Risk Bowtie Impacts			2017 Recorded Capital ($M)	2017 Recorded Expense ($M)
ID	Name	Drivers	Outcomes	Consequences		
C1	Emergency Management	n/a	O1A, O1B	All	$0	$3.7
C2	Fire Management Program	n/a	O1A	All	$0	$0.5
C3	Climate Adaptation Community Grants (not modelled)	n/a	n/a	n/a	$0	$0.5

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does risk-model controls in this report.)

Emergency Management

SCE's emergency management preparedness, response, and recovery operations group supports company-wide emergency coordination and external collaboration with partners to ensure the utility's operations remain resilient in the event of an incident. Edison emergency management preparedness includes training, drills, and exercises, and maintenance of a 24-hour monitoring-and-standby Emergency Operations Center.

Resulting Impact Reduction: Emergency management practices reduce the safety and reliability consequences of Outcomes 1A and 1B. Job hazard assessments are completed for each emergency response field call with safety instructions sent to the various teams and crews dispatched to restore service. Advance preparation and planning can reduce reliability consequences when response plans are activated in the face of severe weather events. SCE response crews are often staged and ready to respond to restore equipment and service during storms and other incidents.

SCE calls out preparatory drills conducted with fire agencies and deliberate grid redundancy design as two of the more compelling beneficial measures within this control category.

Fire Management Program

SCE Fire Management personnel include former firefighters and/or linemen whose duties include:

- Train first responder partners in electrical safety practices;
- Monitor fire threats to SCE assets, and assist in restoration activities;
- Coordinate planning and response operations with first responders and other external partners;
- Monitor climate change impacts on vegetation (grass, heavy brush, chaparral, etc.) threat for contribution to wildfire, including severity and duration of events; and
- Support Edison's efforts to fortify its grid to respond to climate change

Recognizing California's increasing wildfire activity and harm, SCE intends to hire an additional fire scientist and fire management officer to support efforts to prevent and mitigate wildfires, including refinement of wildfire models able to predict ignition and propagation patterns. Resulting Impact Reduction: SCE's Fire Management control measure includes disseminating red flag warnings with the onset of fire weather conditions. Designated SCE staff coordinate with state and federal agencies on tactical efforts such as dropping flame retardant and cutting fire breaks.

Climate Adaptation & Resiliency Community Grants

This control funds projects and programs that advance disadvantaged communities' capacity to adapt to climate change in areas that include community-based education, environmental justice outreach, habitat restoration, disaster preparedness, species protection and environmental stewardship.

Resulting Impact Reduction: Because the program is supported exclusively with shareholder funds, SCE does not model the effect of this control.

MITIGATION PLAN OVERVIEW

Table pulled from p. 530

Table IV-1 – Inventory of Mitigations[57, 58]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Prop.	Alt. #1	Alt. #2
M1	Climate Adaptation & Severe Weather Program		O1A, O1B	All	x	x	x
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	D3	All	All	x	x	
M2b	Situational Awareness, Monitoring & Analytics (Max)	D3	All	All			x
M3	Distribution System Stress Reduction Program		O1A	R		x	

Edison identifies four mitigation measures, which within various combinations with existing control measures, constitute three potential mitigation plan scenarios — a preferred plan and two alternatives. Because two of SCE's four mitigation measures are essentially variations on a them, Edison has put forward three unique mitigation measures.

M1 – Climate Adaptation & Severe Weather Program Description

AP #2 overall: MRR = 6.61; RSE = 0.05 | M-2b alone: MRR = 2.59; RSE = 0.03 AP #1 overall: MRR = 6.38; RSE = 0.06 | M-3 alone: MRR = 0.08; RSE = 0.00

A new program launched in 2018, to serve as a hub for SCE's Climate Adaptation and Severe Weather programs, the unit draws from experts across the utility's business lines, supplemented by outside climate consultants. The program primarily seeks to better understand the impacts of climate change on SCE's grid and facilities, and develop adaptation strategies to address climate impacts over time.

The program seeks to establish uniform standards and metrics to study and mitigate climate risk across the utility, and to promote positive organizational change, including:

- Modifying business processes (e.g., energy procurement and demand forecasting, engineering and equipment procurement, customer service, power generation and delivery, and system design and planning) to enhance SCE's resilience to potential climate impacts;
- Developing an investment and programming strategy and implementation plan to address short- and long-term impacts;
- Identifying indicators to monitor over time to inform decision making;
- Hardening assets and infrastructure (e.g., buildings, IT, electric and generation infrastructure) in response to potential climate impacts;
- Changing engineering criteria and standards to modify to enhance asset and system resilience;
- Updating maintenance practices (e.g. inspection schedules, and preemptive replacement approaches) to enhance asset and system resilience; and
- Advancing SCE climate strategy through policy action and external engagement

Resulting Impact Reduction: This mitigation measure aims to lessen the effects of extreme wildfire events. Edison indicates that an earlier detection of fires will enable a more timely response with improved odds of containing wildfires before they become monster infernos. SCE seeks to be able to access wildfire risk information at the grid-circuit level to better assess how weather conditions may impact utility infrastructure and public safety in high fire risk areas. SCE notes that in addition to the driver described above, its M1 mitigation measure would mitigate the consequence of major weather events by improving the utility's ability to pre-position response equipment and personnel thereby reducing response time, which in turn may reduce durations of outages. Additionally, SCE maintains that by improving the utility's weather forecasting and resulting-load modeling capacity, it will improve its ability to avoid having to procure high-cost energy in the day-ahead and spot markets. Thus, the M1 mitigation measure is expected to have spillover benefits that include lowering the utility's energy procurement costs.

M2a – Situational Awareness, Monitoring & Analytics (Optimal)

Situational awareness provides SCE a window into critical system operations, weather conditions covering its territory and assets at different degrees of granularity, and other factors that affect the daily operation of the grid. SCE's existing Situational Awareness Center (SA Center) is operated by three meteorologists; Edison intends to add two new meteorologists before 2019 who will support increasing workloads and build capabilities in wildfire mitigation.

Additional resources within the M2a category include (A) weather stations; (B) a network of high-def cameras that would provide coverage of 90 percent of Edison's high fire-risk area (HFRA); (C) an Advanced Weather Modeling Tool (an IBM-licensed forecasting and visualization technology that offers an ability to provide forecast information to within 500 meters, and with updates as frequently as that every 15 minutes, a vast improvement over existing SCE models, which typically provide updates on six-or twelve-hour cycles and at resolutions of 3 km or greater) whose features include tracking and analyzing atmospheric inputs such as temperature, wind speed and gusts, humidity, and precipitation; and (D) Advanced Modeling Computer Hardware to power the advanced technology that the M2 category comprises.

Resulting Impact Reduction: The program supported by this mitigation measure studies seasonal weather outlooks and storm preparedness efforts, which allow for planning to optimally respond to potentially severe weather events. The program supported by this mitigation measure aims to reduce the consequences associated with major and catastrophic weather events on the SCE grid.

M2b – Situational Awareness, Monitoring & Analytics (Max)
M-2b alone: MRR = 2.59; RSE = 0.03 M-3 alone: MRR = 0.08; RSE = 0.00

The M2b mitigation measure is a variation on the M2a package, consisting of all its components, plus an additional 2,600 weather stations (two per circuit for each of the 1,300 circuits in HFRAs).

Because SCE, early in its description, references a recent benchmarking effort that revealed the optimal count to be 850 weather stations (conducted with SDG&E, the effort found an optimal ratio to be one weather station for every five HFRA square miles). Thus, the M2b measure, because it is found to be unnecessary, is not viable. As a unviable plan alternative, it should be omitted from the chapter.

Resulting Impact Reduction: Because M2b is an amplified version of M2a, it is inferred that the benefits of this mitigation measure are in line with those of M1a.

Note: SCE should Revise M-2b title for consistency throughout the chapter (i.e., change to "Max" from 2600 weather stations.)
M3 – Distribution System Stress Reduction Program
M-3 alone: MRR = 0.08; RSE = 0.00

SCE typically replaces distribution assets, such as transformers, when they fail in service, or when deterioration is observed in the course of inspection or other fieldwork. Deterioration may include leaks, corrosion, and damage caused by vehicle collisions or acts of nature. Climate change-driven weather conditions, including extreme heat events, can make these assets more susceptible to breaking down earlier than expected.

Resulting Impact Reduction: This mitigation measure would allow for proactively replacing some aging equipment before equipment failure occurs, in turn lessening reliability impacts to customers.

Proposed Mitigation Plan ("Preferred Alternative") and RSE

Edison's preferred alternative, which appears to be adequate, is nonetheless too obvious inasmuch as the utility's two other alternatives are not realistic and therefore, should not be considered serious proposals.

Edison's preferred alternative -- its proposed plan -- would continue all existing controls and include the M1 Climate Adaptation & Severe Weather Program, and M2a Situational Awareness, Monitoring & Analytics mitigation measures.

The component parts that comprise SCE's preferred alternative are described in detail above in the Mitigation Overview section.

Table below pulled from p. 538

Table V-1 - Proposed Plan (2018 – 2023 Total Costs and Risk Reduction)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.24	0.10	7.46	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.02	0.22	1.99	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.81	0.33	2.65	1.08
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	2018	2023	$26.8	$28.0	2.25	0.04	6.08	0.11
			Total - Proposed Plan	$26.8	$56.4	6.32	0.08	18.18	0.22

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

SCE's preferred alternative would reduce potential serious injuries to approximately one per year; reduce potential fatalities by nearly half to close to zero per year; reduce CMI by approximately 28 million per year; and reduce annual financial consequences by approximately $45 million. The preferred alternative is the least costly plan alternative and has the highest RSE (RSE = 0.08; v. Alternative #1 RSE = 0.06; and Alternative #2 RSE = 0.05). SCE's preferred alternative comes with a five-year cost that would total $83.2 million.

SCE's preferred alternative is adequate and is clearly the best among the three identified alternatives. SED notes that SCE's preferred alternative would be stronger if compared against two alternatives that were sound and earnest efforts rather than modified versions of the preferred alternative.

<u>**Alternative Mitigation Plans and Their Relative RSE**</u>

Alternative Plan #1

SCE's Alternative Plan #1 duplicates the controls and measures found within its preferred alternative, but with the addition on one mitigation measure, M3 – Distribution System Stress Reduction Program, which would provide for early retirement (prior to inspection or failure) of assets which could become compromised in hot weather conditions (for more see above Mitigation Overview section).

Because the methodology necessary to implement Alternative Plan #1 has not yet been completed, Alternative Plan #1 cannot be considered realistic or viable, but rather must be considered a placeholder or "throw away" proposal. Because SED is seeking and expects to review three legitimate proposals, SCE's Alternative Plan #1 falls well short of the mark. SCE's Alternative Plan #1, at $51.8 million, comes with a $25 million (30 percent) higher cost than SCE's preferred alternative (p. 540).

AP #1 overall: MRR = 6.38; RSE = 0.06 | M-3 alone: MRR = 0.08; RSE = 0.00
As described above, in the Mitigation Overview section, SCE disqualifies Alternative Plan #1 from consideration based on its existing limitations: "The conceptual mitigation M3 (Distribution Stress Reduction Program) requires further validation through additional studies."

(Table below pulled from p. 540)

Table VI-1 – Alternative Plan #1 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.23	0.10	7.44	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.01	0.22	1.98	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.81	0.33	2.64	1.08
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	2018	2023	$26.8	$28.0	2.25	0.04	6.07	0.11
M3	Distribution System Stress Reduction Program	2018	2023	$25.0	$0.0	0.08	0.00	0.17	0.01
			Total - Alternative Plan #1	$51.8	$56.4	6.38	0.06	18.30	0.17

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

Alternative Plan #2

SCE's Alternative Plan #2 duplicates the controls and measures found within the preferred alternative except to substitute the M2a – Situational Awareness, Monitoring & Analytics (Optimal) mitigation measure with M2b – Situational Awareness, Monitoring & Analytics (Max) mitigation measure, a proposal to nearly triple the number weather stations (2,600 instead of the 850 count proposed by M2a) as described above in the Mitigation Overview section.

As also discussed above, Alternative Plan #2 proposes a program well in excess of the number of weather stations that SCE has determined to be optimal and necessary. Therefore, Alternative Plan #2 cannot be considered realistic or viable, but rather must be looked upon as a placeholder or "throw away" proposal. Because SED is seeking and expects to review three legitimate proposals, SCE's Alternative Plan #2 falls well short of the mark.

SCE voluntarily discards its Alternative Plan #2, recognizing that implementing its M2b proposal would be wasteful. Edison explains that the utility's in-house experts determined after benchmarking that the 850 weather stations number provided by the M2a proposal is sufficient to provide high resolution weather data.(p. 542)

Alternative Plan #2 at $56.8m would be $30m higher cost than SCE's preferred alternative (p. 542)

AP #2 overall: MRR = 6.61; RSE = 0.05 | M-2b alone: MRR = 2.59; RSE = 0.03

Table below pulled from p. 542

Table VII-1 – Alternative Plan 2 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.21	0.10	7.36	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.01	0.22	1.98	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.80	0.33	2.62	1.07
M2b	Situational Awareness, Monitoring & Analytics (Max)	2018	2023	$56.8	$35.9	2.59	0.03	7.44	0.08
			Total - Alternative Plan #2	**$56.8**	**$64.3**	**6.61**	**0.05**	**19.39**	**0.16**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

CONCLUSION

Given the depth of understanding that SCE demonstrates on the challenges it faces due to new extreme weather conditions brought about by climate change, it's disappointing to receive a Risk chapter in such unpolished form and that includes so many problematic postulates. The voice that Edison employs to convey that it is genuinely concerned about the problem of climate change, and that it is committed to locating innovative near-term solutions makes it all the more frustrating that its Chapter 12 at times reads as though Edison were dancing around the issue rather than tackling it head on.

SCE ultimately arrives at an acceptable position with its proposed preferred alternative, but the result is diminished by not having had robust alternatives against which to compare the Plan.

Within RAMP chapters 10 and 12 a large portion is dedicated to the problem of storm-vulnerable assets, and the identification, prioritization, and replacement of these items. Given the severity of the problem and its threat, and given that the RAMP covers the period through 2023, SED believes SCE should have addressed this issue sooner.

NOTABLES AND MISCELLANEA

For its Chapter 12 RAMP risk model, SCE chose to use “99th percentile” data (worst-case weather scenario SCE may expect between before 2023 due to a changing climate) for each of the three event-based climate drivers so as to reflect recent perceptions that expected shifting climate extremes are now present and believed to growing in intensity in the near term (i.e., more frequent and hotter heatwaves, a downward trend in frequency of extreme rain events, and more extreme wildfires). These 99th percentile events were calculated based on a combination of historical data within SCE’s service area and a range of potential future values, using a mix of SCE temperature and precipitation data as well as CAL FIRE data. An extreme rainfall event threshold is a cumulative 1.5 inches of rain over three consecutive days or less. During such events, the electric system can experience significant strain in the form of outages and storm declarations. Edison’s model forecasts three such events per year.

For extreme heat events, SCE identified 101°F as the 99th percentile value for effective temperature, marked by three consecutive days of high heat (common definition of a “heatwave”), which is typically associated with increased load and burden on the electric system; Edison expects four such events per year, or one more annually than the number counted in the years between 1976 and 2017. Interestingly, SCE observes that historically most Southern California heat waves occurred from July to September; but such events now appear to be occurring in spring and fall, while summer events grow more intense and frequent. An increasing tendency for multiple hot days in succession, resulting in heatwaves that last longer, could stress transmission and distribution infrastructure. Particularly problematic, SCE notes, may be the lack of nighttime cooling characteristic of recent California heatwaves, as transformers and other electrical components require regular cooling periods. For extreme wildfire events as the 99th percentile largest wildfire events, based on acres burned. Approximately 35 percent of SCE’s service area is located in high fire-risk areas.
SCE anticipates needing to deploy increased restoration efforts as it has experienced between five to six significant or major storm restoration events per year in the last seven years.