Company: San Diego Gas & Electric Company (U 902 M)
Proceeding: 2024 General Rate Case
Application: A.22-05-015/-016 (cons.)
Exhibit: SDG&E-213

REBUTTAL TESTIMONY

OF JONATHAN T. WOLDEMARIAM

(WILDFIRE MITIGATION AND VEGETATION MANAGEMENT)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

May 2023

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REBUTTAL TESTIMONY OF
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I. SUMMARY OF DIFFERENCES

Table JW-1

TOTAL O&M - Constant 2021 ($000)			
	Base Year 2021	**Test Year 2024**	**Change**
SDG&E	**168,436**	**168,955**	**519**
CAL ADVOCATES	**168,436**	**162,468**	**(5,968)**

Table JW-2

TOTAL CAPITAL - Constant 2021 ($000)		
	2024	**Difference**
SDG&E	**518,507**	**-**
CAL ADVOCATES	**457,337**[1]	**(61,170)**
TURN	**318,207**	**(200,300)**

II. INTRODUCTION

This rebuttal testimony regarding San Diego Gas & Electric's (SDG&E's) request for Wildfire Mitigation and Vegetation Management addresses the following testimony from other parties:

- The Public Advocates Office of the California Public Utilities Commission (Cal Advocates) as submitted by S. Kaur (Exhibit CA-07), P. Li (Exhibit CA-21), and S. Hunter (Exhibit CA-20) dated March 2023.
- The Utility Reform Network (TURN), as submitted by Eric Borden (Exhibit TURN-08) and Robert Finkelstein (Exhibit TURN-15) dated March 2023.

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[1] Cal Advocates reductions to budget codes 20285 – Overhead System Covered Conductor and 19246 – Strategic Undergrounding found in CA-07 utilize the costs presented in the original testimony. SDG&E has since revised these costs in exhibit SDGE-13-2R. To estimate the calculation of Cal Advocates 2024 recommended costs, SDG&E applied the percentage reduction recommended by Cal Advocates recommended to the revised costs described in SDG&E-13-2R.

- The Mussey Grade Road Alliance (MGRA), as submitted by Joseph W. Mitchell dated March 2023.
- Small Business Utility Advocates (SBUA), as submitted by Richard McCann and Steven J. Moss dated March 2023.
- The Protect our Communities Foundation (PCF), as submitted by B. Powers (Exhibit PCF-01) dated March 2023.

As a preliminary matter, the absence of a response to any issue in this rebuttal testimony does not imply or constitute agreement by SDG&E with the proposal or contention made by these or other parties. The forecasts contained in SDG&E's direct testimony, performed at the project level, are based on sound estimates of its revenue requirements at the time of testimony preparation.

My direct testimony supports SDG&E's TY 2024 forecasts necessary to support a comprehensive approach to address the risks of utility-related catastrophic wildfire in our service territory. Wildfire mitigation is essential to promoting SDG&E's top value—the safety of our customers, communities, and employees.[2] Our commitment to wildfire mitigation has led to industry-leading innovations in risk assessments and situational awareness that have been adopted across the state of California and the world.[3] The forecasts supported by my direct testimony are risk-informed, necessary, and reasonable to address the important and pressing needs to mitigate the risk of wildfire and reduce the necessity of Public Safety Power Shutoffs (PSPS). Further, these investments and costs support activities necessary to meet state and regulatory mandates, goals, and directives to reduce the risk of wildfire and comply with SDG&E's Wildfire Mitigation Plan (WMP).

A. CAL ADVOCATES

The following is a summary of Cal Advocates' positions on Wildfire Mitigation and Vegetation Management:[4]

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2 SDG&E-13-2R at JTW-1.

3 SDG&E-13-2R at JTW-1-2.

4 "March 27, 2023, Public Advocates Office Report on Results of Operations for San Diego Gas & Electric Company Southern California Gas Company Test Year 2024 General Rate Case SCG Clean Energy Innovations, SDG&E Wildfire Mitigation and Vegetation Management, and Electric Distribution Capital Expenditures (Part 2)"

- Cal Advocates agrees with SDG&E's approach to perform covered conductor and undergrounding programs to the riskiest power lines as presented in this GRC.
- Cal Advocates recommends a unit cost cap for both strategic undergrounding and covered conductor installation based upon the risk quintiles for the circuit segment.
- Cal Advocates recommends a forecast methodology that utilizes 2021 unit costs as the basis for reducing 2024 cost forecasts across several operations and maintenance (O&M) and capital programs.
- Cal Advocates provides conflicting testimony regarding SDG&E's proposal for balancing treatment of Wildfire Mitigation costs, but generally recommends a mechanism that assures accountability and protection from ratepayers given uncertainties in the field.[5]

B. TURN

The following is a summary of TURN's positions on Wildfire Mitigation and Vegetation Management:[6]

- TURN disagrees with SDG&E's risk modeling associated with the scoping of its covered conductor and undergrounding programs.
- TURN proposes an alternative Risk Spend Efficiency (RSE) calculation methodology which relies solely on wildfire risk and does not consider PSPS impacts.
- TURN recommends an increase to SDG&E's covered conductor installations from 60 miles to 100 miles and a decrease to

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[5] CA-07 at 26 (appearing to support the continued recording of WMP-related costs in a continued memorandum account); CA-20 at 20:15-26 (supporting a two-way balancing account for SDG&E's WMP with a "reasonableness review of any recorded costs in excess of 110% of the expenditure amounts authorized in this decision.")

[6] March 27, 2023, Prepared Direct Testimony of Eric Borden Addressing San Diego Gas & Electric's Test Year 2024 Wildfire Mitigation Hardening Measures and Related Wildfire Risk Modeling Issues Submitted on behalf of The Utility Reform Network.

SDG&E's forecasted undergrounding installations from 150 miles to 35 miles.

- TURN recommends SDG&E's Vegetation Management Balancing Account (VMBA) be modified to a one-way balancing account. TURN recommends SDG&E's request for a Wildfire Mitigation Balancing Account (WMPBA) be denied.

C. MGRA

The following is a summary of MGRA's positions on Wildfire Mitigation and Vegetation Management:[7]

- MGRA takes issue with SDG&E's risk modeling assumptions related to the effects of wildfire, including wildfire smoke impacts and PSPS.
- MGRA requests SDG&E prepare an alternative proposal to its grid hardening programs consisting of covered conductor, Advanced Protection, and PSPS wind-gust thresholds to compare with SDG&E's current proposal.

D. SBUA

The following is a summary of SBUA's position on Wildfire Mitigation and Vegetation Management:[8]

- SBUA proposes that SDG&E's grid hardening initiatives be replaced with either residential microgrids or community microgrids to serve all customers in the High Fire Threat District (HFTD).

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[7] March 27, 2023 Direct Testimony of The Mussey Grade Road Alliance San Diego Gas and Electric Company 2024 General Rate Case.

[8] March 27, 2023 Direct Testimony of Richard McCann, PhD. And Steven J. Moss, MPP on Behalf of Small Business Utility Advocates.

E. PCF

The following is a summary of PCF's position on Wildfire Mitigation and Vegetation Management:[9]

- PCF proposes that customer-sited solar generation plus battery systems be installed at all customer locations in HFTD Tier 3 as an alternative to SDG&E's grid hardening programs.

III. GENERAL REBUTTAL

A. RISK ASSESSMENT AND MODELING

1. SDG&E's Wildfire Next Generation System-Planning Model

My direct testimony addresses how SDG&E uses its Wildfire Next Generation System Planning (WiNGS Planning) Model to better inform its investment strategies with respect to grid hardening—namely, the use of covered conductor and strategic undergrounding of electrical infrastructure. The WiNGS model allows SDG&E to both target the areas of the highest wildfire risk and prioritize work accordingly, in addition to identifying the optimal risk mitigation strategy. In preparation of SDG&E's 2023-2025 Wildfire Mitigation Plan (2023 WMP), SDG&E incorporated new data inputs to the WiNGS-Planning model to, among other things, capture additional cost efficiencies, update ignition and weather data, and capture any risk reduction of existing infrastructure. These updates led SDG&E to re-shape its grid hardening strategy to perform additional undergrounding of electric lines over the next 10 years and reduce corresponding covered conductor installation. By executing on this plan, SDG&E predicts it will significantly reduce the risk of utility-related wildfire and the impacts of PSPS within the service territory.

SDG&E continues to leverage input from stakeholders and lessons learned to enhance its risk modeling capabilities, which remain a subject of significant focus of the Office of Energy Infrastructure Safety (Energy Safety) and SDG&E's WMP. In 2022, SDG&E continued its culture of continuous improvement in this area by embracing model changes—with the feedback of many of the parties to this proceeding—increasing collaboration with other California utilities and participating in workshops hosted by Energy Safety. This approach has led to additional

[9] March 23, 2023 Prepared Direct Testimony of Bill Powers, P.E. on Behalf of The Protect Our Communities Foundation.

improvements, more accurate wildfire risk assessment, and has increased the effectiveness of the portfolio of proposed mitigation. TURN acknowledges that SDG&E's modeling efforts are "vastly improving."[10] SDG&E is transitioning its models from static excel files to the "cloud" to allow for centralized, more dynamic data that improves transparency, reproducibility, and allows more agile risk assessments as data and other capabilities improve.

Completely contrary to TURN's analysis, many of the initiatives and forecasts addressed in my testimony are rooted in SDG&E's risk modeling capabilities.[11] TURN's preposterous suggestion that SDG&E has failed to support *any* of its wildfire mitigation-related requests and the Commission should even consider "rejection of its entire proposal"[12] demonstrates the lack of value of TURN's analysis. And simply put, TURN's alternative asks the Commission to place economics over safety. As described in my direct testimony and this rebuttal, SDG&E's risk-informed approach strikes an appropriate and reasonable balance between promoting safety through risk reduction and customer affordability.

SDG&E takes a risk-informed approach to its hardening strategy to maximize its effectiveness at reducing the risk of wildfire and mitigating customer PSPS impacts while balancing the costs to customers. As described in my direct testimony, many of these investments represent a "once in a lifetime" effort to modernize the electrical grid to mitigate wildfire risk and meet the Commission and Energy Safety's direction to reduce the need for PSPS, with added benefits including preparation for electrification. For the reasons summarized below, the Commission should accept SDG&E's risk modeling approach and current outputs and recommendations as providing a reasonable and informed strategy toward wildfire mitigation.

2. TURN Significantly Understates Wildfire Risk

TURN makes the following inaccurate assertion regarding the assumption used by SDG&E on its wildfire risk baseline estimation:

> The assumption that SDG&E makes is that there will be a catastrophic fire once every 20 years that burns 500,000 acres, an expected value of 25,000 acres per year…This is not a realistic modeling assumption. Indeed, it is based on a review of statewide fires, not those particular to SDG&E's service territory or the San Diego region. Further, the expected annual number of acres burned, 25,000, is not

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[10] Borden at 1:4-5.

[11] *Id*. at 7-12.

[12] *Id*. at 11-12.

> realistic when compared with actual data for the San Diego region. Putting aside the cause of fires for the moment (the figure includes all sources), annual acres burned in San Diego County have been far less than 25,000 in all years but one since 2008.[13]

The Commission should discard TURN's assertion that a potential worst-case scenario of 500,000 acres burned (SDG&E's assumption regarding a catastrophic event) is "not a realistic modeling assumption."[14] TURN's analysis is overly simplistic and lacks any basis in existing data. If SDG&E were to leverage the past 15 years of historical wildfire records and calculate an average value, or even simply take the highest value observed, it would likely result in an underestimation of the actual wildfire risk due to the limited sample size, changing environmental conditions, and potential for unpredictable events. In the world of a changing climate, assuming because something hasn't happened in the past it won't occur in the future can lead to disastrous results. The tragic fires of 2017 and 2018 proved that to be the case and is precisely the outcome we aim to avoid. SDG&E leverages its extensive data to quantify its mitigations based on a proper probabilistic analysis of the potential worst-case scenario. Mitigations should be appropriately risk informed and not based on an unreasonably small sample size such as past fires in the limited number of years as proposed by TURN.

Based on a conveniently selected sample size, TURN inaccurately concludes that a fire of 200,000 acres in 15 years is a "reasonable, but likely conservative estimate to represent both average and catastrophic wildfire years."[15] In its analysis, TURN ignores the many highly destructive fires that burned more than 200,000 acres—all occurring in the last 20 years. The Cedar Fire (2003) that occurred during a Santa Ana wind event in San Diego County burned 273,246 acres. The three catastrophic fires of 2003 (Cedar, Paradise, Otay) combined burned 376,237 acres – roughly 13 percent of San Diego County's total land mass. Even TURN acknowledges that the Witch Fire, which occurred 16 years ago, burned nearly 200,000 acres, but somehow dismisses that incident, ironically because of it being the result of utility infrastructure.[16]

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[13] TURN-08 (Borden) at 29, lines 13-22.

[14] *Id*. at 29:17.

[15] TURN-08 (Borden) at 30, lines 13-14.

[16] *Id*. at 30:7-8.

Furthermore, based on SDG&E's assumptions of structures destroyed per acre burned, cost per acre burned, and cost per structure destroyed,[17] TURN's suggested assumption of 200,000 acres burned in 15 years or 267,000 acres burned in 20 years[18] is inconsistent with SDG&E's Power Law estimation of extreme wildfire[19] and MGRA's Power Law recommendation: "MGRA argued that a power law distribution should be used because it was consistent with academic findings regarding wildfire spread, and would not underestimate catastrophic losses" and "including a power law model for large losses and a higher value for wildfire smoke losses would increase risk scored without artificial amplification of the MAVF safety component."[20] Further, TURN has presented no arguments in its acres burned estimation to address the "bias" mentioned repeatedly in MGRA's testimony, that since 2013, proactive de-energization (PSPS) events have resulted in a data bias in areas with extreme weather conditions: "The areas most likely to be affected by power shutoff are those that are most likely to have significant exposure to high wind conditions and high fire potential. Therefore, the most dangerous areas in the SDG&E service territory have their wildfire risk *artificially suppressed*."[21]

TURN's suggestion to use "the 1 in 20-year criteria, [equating] to a major fire of around 267,000 acres every 20 years"[22] assumes that the worst-case scenario has already been experienced in SDG&E's service territory. This is incorrect from a policy perspective, as this would require accepting the worst-case scenario would be realized again within SDG&E's service territory exposing SDG&E customers, first responders, and environment to an unacceptable level of risk. Because TURN's RSE calculations rest upon this very flawed assumption of wildfire risk, the Commission should disregard both the assumption as well as TURN's conclusions regarding how SDG&E addresses wildfire risk, as further discussed below.

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17 *See* SDG&E response to TURN-SEU-017 Question 8, attached her in Appendix B starting at JTW-B-3.

18 TURN-08 (Borden) at 30, fn 58.

19 MGRA (Mitchell) at 77, lines 12-13.

20 MGRA (Mitchell) at 7, lines 9-12 and 20-22.

21 *Id*. at 15:3-4 (emphasis added).

22 TURN-08 (Borden) at 30, fn 58.

3. Covered Conductor vs Undergrounding

a. SDG&E's Assessment of the Risk Reduction of Covered Conductor and Undergrounding is Well Founded and Reasonable

TURN and MGRA generally take the position that SDG&E should implement additional covered conductor installation and reduce its proposed strategic undergrounding efforts. While admittedly the most expensive wildfire mitigation strategy, even MGRA concedes that it is also the most effective. Moreover, unlike covered conductor, undergrounding provides additional benefits, namely PSPS risk reduction but also environmental benefits and reduced lifecycle costs. These lifecycle costs are further discussed in my Second Revised Direct Testimony as well as the Supplemental Testimony of Kevin Geraghty, SDG&E Ex-49. These lifecycle cost savings provide customers an additional value and further promote cost parity when comparing the life of covered conductor versus undergrounded assets.

MGRA is incorrect in claiming that SDG&E shifted its hardening strategy in response to PG&E's 10,000 mile project or the passage of Senate Bill 884.[23] As described extensively in my direct testimony, SDG&E revised its forecasted undergrounding and covered conductor projects due to enhancements in its risk modeling approach and the recommendations of a new iteration of its WiNGS-Planning model, WiNGS 2.0. This new model was implemented in preparation for SDG&E's 2023-2025 Wildfire Mitigation Plan[24] submission and addresses improvements in modeling and data science to enhance the safety and reliability of SDG&E's infrastructure. MGRA acknowledges that SDG&E "has made considerable progress in its ability to analyze wildfire risk since MGRA began working on the SDG&E power line wildfire problem in 2007. In fact, each new iteration of SDG&E's risk modeling incorporates many advances and innovations, and each of its RAMP, GRC, and WMP filings introduces substantive corrections and improvements."[25]

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[23] MGRA at 3. While SDG&E did not shift its scope of work in response to SB 884, SDG&E does contend that the passage of that legislation indicates a general support by the California Legislature in favor of expedited undergrounding to reduce wildfire mitigation in the highest risk areas (*See* Pub. Util. Code §8388.5(a), which is precisely what SDG&E's forecasted work does.

[24] SDG&E's 2023-2025 Wildfire Mitigation Plan, *available at* https://www.sdge.com/2023-wildfire-mitigation-plan.

[25] MGRA at 27.

And while MGRA acknowledges that modeling improvements continue, and it is "not reasonable to expect SDG&Es risk analysis to be perfect before proceeding with mitigation,"[26] SDG&E disputes the claim that it is more reasonable to "favor less expensive mitigations in the short term while SDG&E's ability to estimate risk improves."[27] That may be a reasonable approach to short term mitigation strategies, such as asset replacements, span-level bare wire hardening, and PSPS resiliency programs. But SDG&E's covered conductor and strategic undergrounding programs are the "comprehensive and expensive mitigations"[28] that need to occur for longer-term reduction of wildfire and PSPS risk. These initiatives are necessary now to promote safety.

MGRA also incorrectly claims, "SDG&E's testimony on its undergrounding program fails to adhere to the S-MAP / RAMP principals that cost-effective risk reduction should help to guide utility safety spending, despite a complex and contorted approach that makes undergrounding appear to have an RSE greater than that of covered conductor."[29] The WiNGS-Planning model calculates granular circuit-segment mitigation RSE values that incorporates a thorough risk reduction calculation accounting for both likelihood and consequence of risk events. The model subsequently assesses both pre- and post-mitigation risk scores to derive the resultant risk reduction. A full cost analysis is performed within the denominator of the RSE metric to assess the cost difference between the pre and post mitigation states, accounting both for the cost of construction of the assessed mitigation and lifecycle cost on the pre- vs. post-mitigation state of the system. For lifecycle cost analysis, SDG&E considered the historical cost of vegetation management activities, inspections, and cost associated with PSPS events over the lifetime of the assets. On average there is a 20% cost savings over the lifetime of the segment when we underground the segment as compared to leaving it as overhead.

SDG&E notes that PSPS risk is not incorporated in this RSE metric, because of the circuit-connectivity assessment of PSPS risk compelling the most accurate PSPS risk benefit to be calculated best at circuit-level granularity, rather than circuit-segment level granularity. Thus, TURN's argument that SDG&E is somehow selecting its hardening investment based on PSPS

[26] *Id*. at 28:18-19.

[27] *Id.* at 28:21-23.

[28] *Id*. at 28:23-24.

[29] MGRA (Mitchell) at 31:4-7.

risk reduction is generally inaccurate and based on a flawed understanding of SDG&E's WiNGS-Planning model. However, undergrounding is acknowledged to severely reduce or eliminate PSPS risk as well.[30]

MGRA states "According to SDG&E, the efficacy of covered conductor is estimated to be 65%, so a solution emphasizing covered conductor could never reach SDG&E's target goal of 83%. Therefore SDG&E's overall solution must consist primarily of undergrounding with covered conductor comprising only a minor component."[31] MGRA wrongfully insinuates that SDG&E chose an arbitrary number of 83% for the purpose of including more undergrounding in its mitigation portfolio. The two numbers compared in this statement were derived via studies and analysis independent of each other—one on the efficacy of covered conductor and the other assessing how SDG&E could balance wildfire risk reduction and customer affordability. The covered conductor efficacy rate of 65% is based on efficacy studies, while the 83% risk reduction goal was based on a cost/value study showing 83% as the optimal risk reduction target.

The goal of the WiNGS Planning model is to propose lasting, cost-effective mitigation to reduce wildfire risk and minimize the impacts of PSPS events to SDG&E's customers. In this respect, SDG&E's decision tree for the mitigation selection process is both sound and cost-effective for SDG&E's customers. MGRA states, "In no case are RSEs compared between undergrounding and covered conductor for specific circuit segments in order to select between them"[32] This comparison is not part of the logic for the decision tree because the mitigation selection methodology between covered conductor and undergrounding is intrinsic to the methodology. The decision tree is built with the premise that should a segment qualify for an undergrounding type of mitigation based on RSE logic, then that will be the mitigation recommended by the model. The reason for this is that undergrounding provides the most robust protection against wildfire risk and has the added benefit of eliminating PSPS risk. Furthermore, hardening decisions are not made within the modeling vacuum. The WiNGS Planning model mitigations are thoroughly reviewed for real-world application during the Desktop Feasibility Study, which is fundamental to the scoping process. This study ensures that the appropriate

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30 *See, e.g.* MGRA at 31:24. This assumption is somewhat built into SDG&E's WiNGS-Planning model.

31 MGRA (Mitchell) at 48:5-8.

32 MGRA (Mitchell) at 48:8-10.

mitigations are applied to each segment considering both the WiNGS Planning recommendations as well as real-world feasibility.

MGRA is also incorrect in stating that "SDG&E assigns a 0% effectiveness of covered conductor in reducing PSPS risk, even though they are planning to raise covered conductor PSPS wind gust thresholds with respect to bare wire," and "Current risk modeling takes no changes into account and assigns no PSPS risk reduction to covered conductor." SDG&E does not understate the value of covered conductor in reducing some PSPS impacts, but undeniably PSPS will continue at scale if the Commission accepts MGRA and TURN's analysis.[33] SDG&E agrees that there is an ongoing possibility of some PSPS events even with the implementation of its comprehensive wildfire hardening plan. Unhardened lines, bare hardened lines, and those utilizing covered conductor could still experience circumstances requiring the use of PSPS.[34] But the number of customers experiencing those impacts is anticipated to dramatically decline upon completion of SDG&E's hardening strategy. SDG&E believes the shift in strategy to increase undergrounding in strategic areas is the best method to reduce long-term impacts due to PSPS events. The majority (17) of top (20) segments that have a high frequency of PSPS are being mitigated by undergrounding work which will minimize the impacts of PSPS on these frequently impacted customers.

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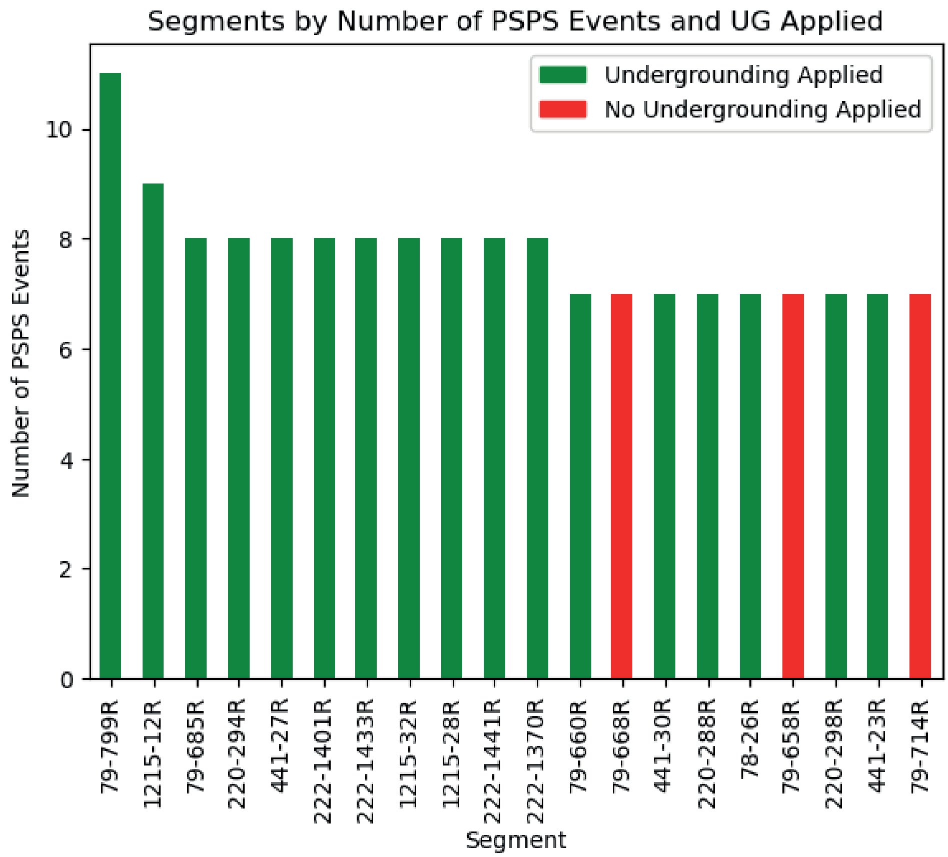
[33] MGRA assumes the continuation of PSPS in advocating that tracking vegetation contacts "(during PSPS events) will provide a clearer picture of how robust covered conductor is against vegetation contact and extreme wind events." MGRA at 33:17-22.

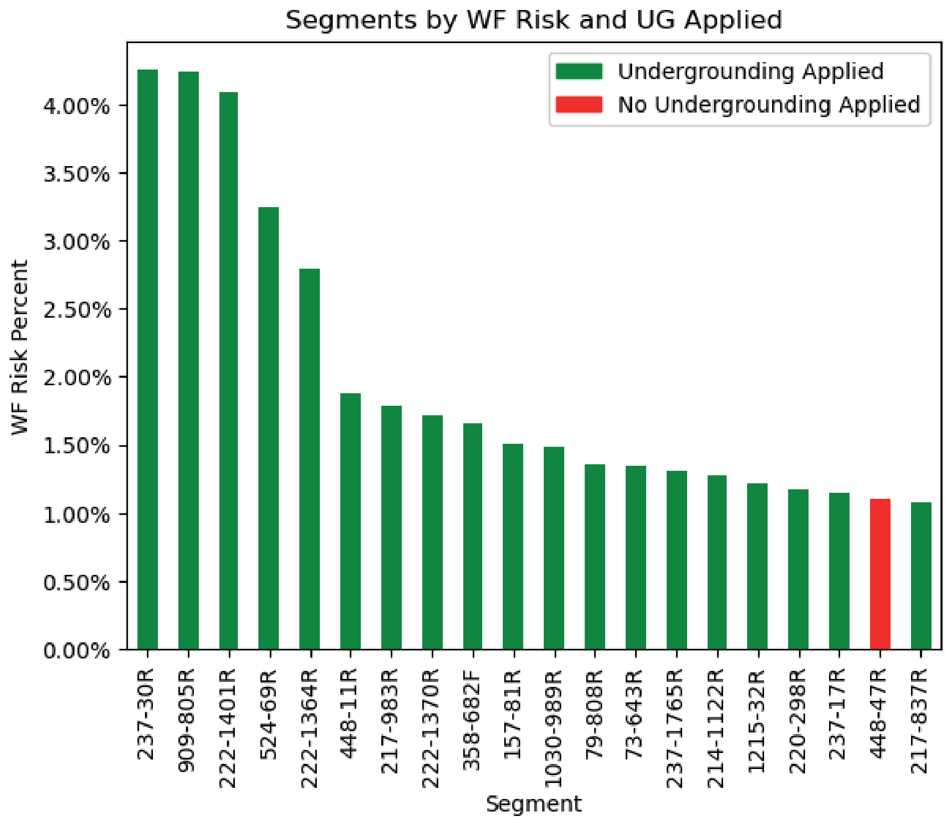
[34] *See*, *e.g.,* MGRA at 51:16-20.

Figure JW-3



Undergrounding will minimize PSPS impacts and is also the best method to reduce wildfire risk. As shown below, the majority (19) of top (20) segments with the highest Wildfire risk percent are being mitigated by undergrounding work.

Figure JW-4



b. SDG&E's WiNGS-Planning Model and 83% Risk Reduction Hardening Target Appropriately Balances Cost and Risk Reduction

My direct testimony describes SDG&E's selection to target 83% wildfire risk reduction through its grid hardening efforts. As described in my direct testimony and herein, the 83% target remains a reasonable and prudent approach to balance the need to harden SDG&E's riskiest infrastructure and the costs associated with that work.

TURN and MGRA make statements that SDG&E's long term wildfire risk reduction target is not the optimized point for balancing cost and effectiveness.[35] SDG&E acknowledges that the balance between cost and effectiveness may result in changes to the 83% target as it is adjusted to align with continually-improving, long-term risk mitigations.[36] But given today's

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35 TURN-08 (Borden) at 8; MGRA (Mitchell) at 51:22-25.

36 Any changes to strategy or SDG&E's risk reduction targets can be addressed in real time through, and further justify the application of, a two-way balancing account, as discussed in my direct testimony and below.

knowledge and data, SDG&E's effort to balance wildfire risk reduction and costs in pursuit of never having a catastrophic wildfire caused by utility equipment is reasonable. Conversely, the methods recommended by TURN and MGRA result in far less risk reduction, albeit at a lower cost. SDG&E's recommended approach, as represented by the green "default" point on the table below, strikes a reasonable middle ground using a data driven and risk-based approach.

Figure JW-5: Cost vs Wildfire Risk Reduction[37]

If SDG&E were to adjust the segments that are currently forecasted for underground mitigation over the next 10 years and adjust the mitigation to covered conductor only, that would adjust SDG&E's target to require 1,760 miles of covered conductor. The models project such an approach would result in a reduction of wildfire risk of **only approximately 50%** at the conclusion of the 10-year period, as opposed to the current goal of 83% wildfire risk reduction with our optimized run through WiNGS-Planning methodology. Alternatively, if we adjust all 1,760 miles to underground, SDG&E would achieve 85% risk reduction, however costs would increase significantly. Further, analysis of this curve continues to place SDG&E's strategy at the

[37] Cost estimates are derived from SDG&E's WiNGS-Planning model, rendering relative costs between scenarios accurate.

correct inflection point prior to costs rising at an exponentially high rate. Using the same per-mile cost estimates for all three runs, SDG&E finds that the WiNGS-Planning Optimized run has the best cost effectiveness portfolio for average cost to wildfire risk reduction as shown above in Figure JW-5:

Table JW-3: Mitigation Portfolios

Mitigation Portfolio	Dollar to Wildfire Risk Reduction (WFRR)
Optimized WiNGS-Planning Portfolio	$31M for every 1% WFRR
Undergrounding all mitigated segments	$42M for every 1% WFRR
Covered Conductor all mitigated segments	$36M for every 1% WFRR

To change from Optimized run to underground the entire portfolio it would give us 2 extra WFRR % (83% to 85%) but would come at a steep cost of $580M per 1% WFRR. While going with CC only would cost roughly $1.83B (as opposed to $2.62B in the Optimized run), but it would only achieve 50% WFRR, and not be near our 83% wildfire risk reduction target.

MGRA further disputes SDG&E's approach of applying a graduated process of mitigation selection.[38] WiNGS-Planning is the main prioritization model for defining undergrounding and covered conductor work throughout the territory and outputs are primarily rooted in assessing reduction in wildfire risk. WiNGS-Planning calculates PSPS risk scores and PSPS risk reduction associated to mitigations considered within the model. But since post-mitigation PSPS risk reduction assessment depends on the unique combination of hardening states achieved on circuit-segments within a given circuit, incorporating PSPS risk scores directly into the model decision-making framework would require a complex optimization simulation function to be built.[39]

Using the logical assumption that undergrounding has on average a relatively higher PSPS risk reduction and a definite higher wildfire risk reduction portfolio than covered conductor, the undergrounding RSE is first assessed within the decision-making framework to see if it meets the threshold within the model. If the model does not support the selection of undergrounding, it continues on to assess the effectiveness of covered conductor through the

[38] *See,* MGRA at 48:4-10.

[39] As part of its efforts to continuously improve SDG&E's risk models, SDG&E plans to explore these possibilities at a future date.

RSE. WiNGS-Planning also incorporates an overhead to underground construction contingency estimation. This goes into the post-mitigation mileage estimation that influences the cost assessed to be incurred as a result of the undergrounding project analyzed at the circuit-segment granularity, helping provide a more accurate assessed cost for the endeavor.

4. The Commission Should Reject TURN's Suggestion to Disregard any Quantification of PSPS Risk Reduction

TURN recommends that the Commission "remove PSPS risk reduction from the calculation due to the issues noted above, and the fact that undergrounding should be driven by reduction of wildfire risk, not PSPS."[40] Like Energy Safety,[41] SDG&E rejects this notion and stands by its position to analyze PSPS risk reduction in pursuit of improving both safety and reliability for its customers, including those from vulnerable populations.

At the outset, as discussed elsewhere in this rebuttal testimony, SDG&E's hardening selection process is rooted in reduction of wildfire risk, with PSPS reduction providing an additional benefit. As referenced in the MGRA testimony: "SDG&E will continue to pursue more advanced approaches to quantifying PSPS in the future and potentially conducting more studies to guide its assessments."[42]

Contrary to TURN's position, the WiNGS-Planning model was created to increase the granularity and accuracy of the Wildfire and PSPS models at the minimum level possible (currently at the circuit segment level): "Underlying this risk modeling is a more granular model that calculates risk at the circuit segment level called the WiNGS model."[43] SDG&E's workbook RSEs are contingent on average feeder configuration (the average number of customers and average population demographics); however, WiNGS-Planning contains actual circuit segment level configurations to better target risk.

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40 TURN-08 (Borden) at 33:8-10.

41 *See*, Office of Energy Infrastructure Safety, 2023-2025 Wildfire Mitigation Plan Process and Evaluation Guidelines, December 6, 2022 at 9 (WMP evaluation criteria include "The electrical corporation demonstrates a clear action plan to continue reducing utility-related ignitions *and the scale, scope, and frequency of Public Safety Power Shutoff (PSPS) events*. In addition, the electrical corporation focuses sufficiently on long-term strategies to build the overall maturity of its wildfire mitigation capabilities while reducing reliance on *shorter-term* strategies such as PSPS and enhanced vegetation management." (emphasis added))._

42 MGRA (Mitchell) at 16:2-5.

43 TURN-08 (Borden) at 17:17-18.

SDG&E WiNGS-Planning is continuously evolving as model assumptions, methodologies, and feedback are integrated regularly to enhance the model. As stated multiple times in testimony, public workshops, and data requests, including in response to a data request from MGRA, "SDG&E will continue to assess wildfire risk in collaboration with OEIS, academia, industry leaders, government agencies, and other stakeholders, and will update its modeling assumptions during the RAMP and WMP filings."[44] Additionally, "The Probability of Failure and Ignition models that are part of the Circuit Risk Index are in constant development as SDG&E is continuously working with industry experts, academia, government agencies, and other stakeholders to better understand and quantify the wildfire risk in its service territory."[45]

Regarding PSPS risk reduction calculations for SDG&E's undergrounding proposal, TURN's asserts "…according to SDG&E's calculations, the undergrounding of 125 miles of lines in the test year (TY), equivalent to 3.6 percent of the utility HFTD overhead system, will eliminate 30 percent of PSPS risk, and 6 percent of wildfire risk. This is highly unlikely, given the PSPS events can occur across the HFTD."[46] TURN incorrectly implies that PSPS risk is equally distributed across HFTD, while in fact, when extreme weather conditions are present, not every circuit in Tier 2 or Tier 3 experiences de-energization events. Further, not even full circuits are de-energized as, whenever possible, to limit the number of customers without power, SDG&E de-energizes its customers at the downstream Supervisory Control and Data Acquisition (SCADA) Sectionalizing device (i.e. segment) level and not at the Circuit Breaker level. SDG&E's circuit-segment hardening approach is a tailored and targeted means by which to address both wildfire and PSPS risk—fully hardened circuits experience uniform PSPS risk reductions assuming adoption of SDG&E's strategy.

TURN's statement illustrates a lack of understanding of how de-energization events are executed and the methodology used to estimate the PSPS Risk baselines for Tier 3 and Tier 2. Contrary to TURN, it is completely appropriate to apply "a 100 percent mitigation effectiveness factor for undergrounding to all expected average PSPS events on the system, rather than an approximation of the PSPS events expected to be experienced by the particular 125 miles that are

[44] MGRA (Mitchell) Appendix B at 22.

[45] MGRA (Mitchell), Appendix B (*citing* MGRA-SDGE-004 at 7).

[46] TURN-08 (Borden) at 23:4-7.

undergrounded,"[47] because of the circuit segment based hardening approach previously described. In addition, TURN requested this data requiring an estimate to which SDG&E provided detailed information in response. In response to this data request, SDG&E clearly showed that the PSPS baseline estimation is calculated with the assumption of 18,850 customers[48] that could potentially experience a de-energization event, and by applying undergrounding as a mitigation, that total count is reduced to 8,733 customers.[49]

MGRA expresses apparent confusion in its assessment of the WiNGS-Planning Wildfire and PSPS risk scores.[50] WiNGS-Planning is the main prioritization model for planning undergrounding and covered conductor work throughout the territory. The mitigation-specific RSEs and risk metrics within WiNGS-Planning are relative to the scope within the tool only, and do not necessarily generalize outside of the model to global RSEs reported out for program effectiveness, which are handled using similar risk calculations and methodologies, but are performed in isolation of WiNGS-Planning modeling and are performed at a different granularity. The RSEs in WiNGS-Planning are granular to the circuit-segment level, defined as the spans in-between two SCADA sectionalizing devices. The WiNGS-Planning model does a top-down calibration process, whereby the circuit-segment specific risk elements are calibrated to ensure the total sum circuit-segment Wildfire and PSPS risk scores in the model equal the global reported HFTD territory risk scores. This calibration helps ensure that the outputs of the model are aligned in scale with specific reported global risk metrics tied to the same scope the model captures, namely the HFTD territory risk.

Unlike wildfire risk reduction, PSPS risk reduction is dependent on the conditions that the complete segment must be mitigated along with its associated upstream segments within a circuit. Due to construction practices that mitigate portions of segments each year, the full PSPS risk reduction will not be fully realized until the final span has been undergrounded, which may take a few years. This is different from wildfire risk reduction where the benefits are immediately realized because even portions of segment system hardening experience risk reduction as the system has become more resilient to ignitions. The approach for PSPS risk

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47 TURN-08 (Borden) at 23:9-12.

48 SDG&E response to TURN-SEU-017 Question 8, attached here in Appendix B starting at JTW-B-3.

49 SDG&E response to TURN-SEU-017 Question 6hi, attached here in Appendix B at JTW-B-2.

50 MGRA (Mitchell) at 63:18-64:3.

reduction requires persistent and strategic construction planning, but the full PSPS risk reduction will eventually come to fruition as complete segments are hardened. During the first years of mitigation applications, little PSPS risk reduction may be observed as only portions of segments will be hardened, but as the program matures, the PSPS risk reduction will progress rapidly.

In 2023, 170,324 customers could be eligible for PSPS per the WiNGS Planning Model, meaning there is some probability associated with a future PSPS event. Over the total portfolio of mitigations, SDG&E forecasts the PSPS risk percent dropping by more than 50% and the total customers eligible for PSPS will be reduced by 34,148 customers (20% reduction). A further breakdown of reduction reveals the following:

- Non-Classified Customers by 30,139 (19.5%)
- Medical Baseline Customers by 3,080 (26.5%)
- Urgent Customers by 75 (30.1%)
- Essential Customers by 613 (20.6%)
- Sensitive Customers by 241 (35.1%)

Figure JW-1: Total Probability of PSPS events

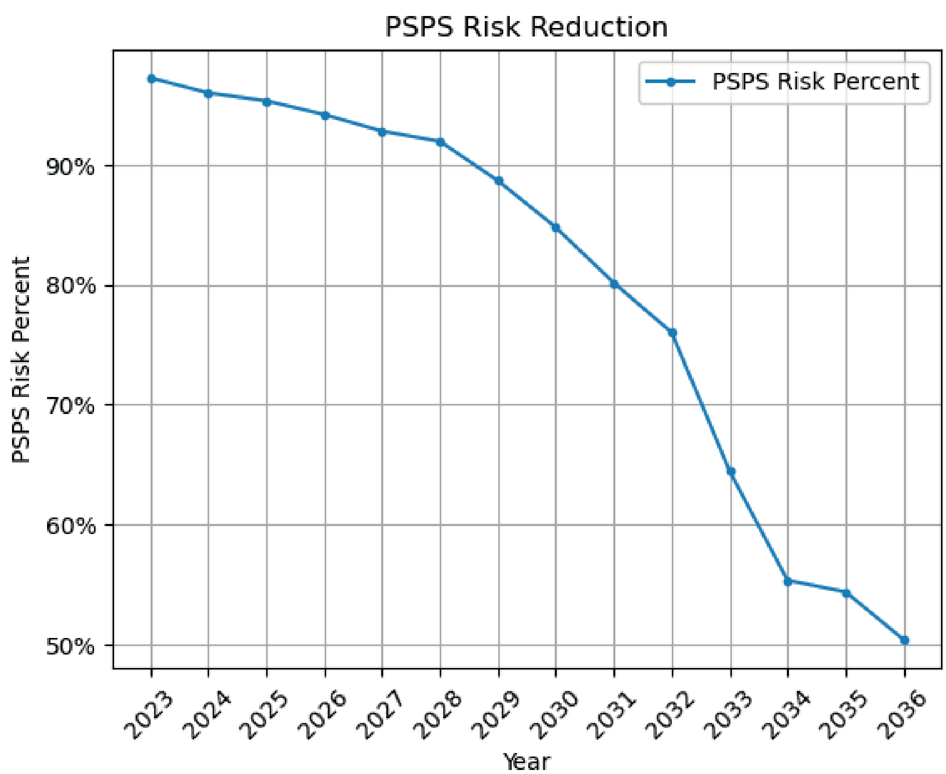
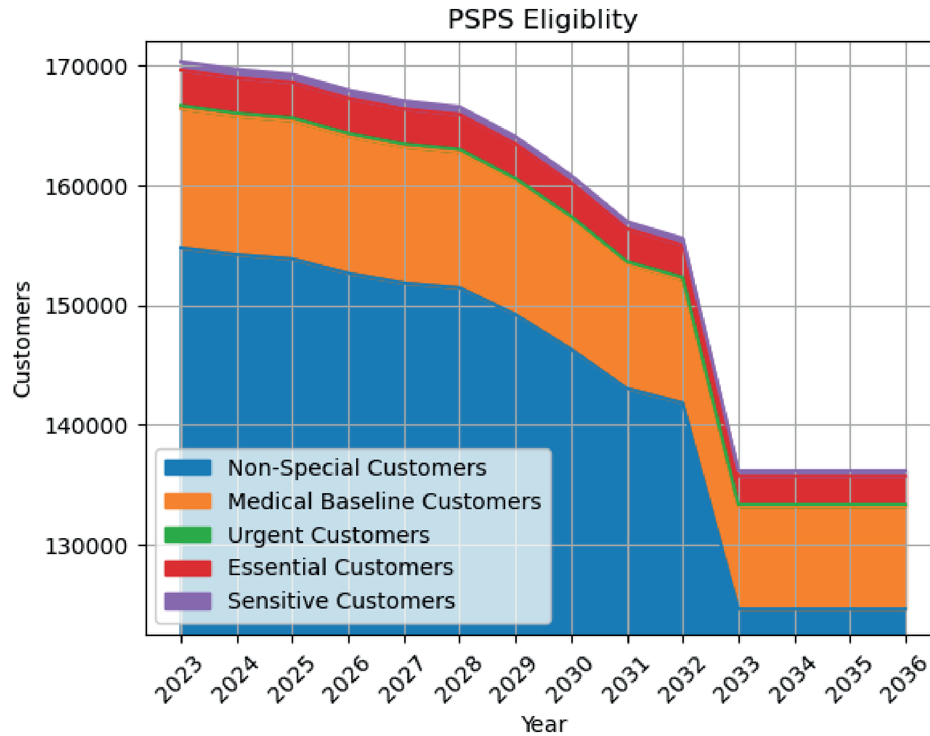


Figure JW-2: Reduction in customers eligible for PSPS



5. Wildfire Smoke Impact Analysis Should Not Inform Hardening Investments at This Time

MGRA asserts the following:

> "It is important to emphasize the exact magnitude of wildfire smoke health effects are at this time highly uncertain, and sources can vary across a wide range... A more correct methodology will require the simulation of smoke plumes in conjunction with wildfire simulations and estimation of the effect of those plumes on local populations using epidemiological data and analysis. No such analysis is currently available to utilities. The effect of such an analysis, when it becomes available, is likely to have a significant impact on how utility risk is assessed across the landscape. Certain areas are going to be found to be more likely than others to produce smoke plumes that reach population centers under prevailing fire weather conditions, leading to potentially significant increases in their relative risk scores."[51]

During the December 2022 Energy Safety Risk Modeling workshop, SDG&E explained that, as a utility, its ability to assess wildfire smoke impacts are limited, but there are several alternative sources, including federal and state agencies, as well as the academic community,

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[51] MGRA (Mitchell) at 13:24-14:8.

who are better equipped to quantify the holistic impact of wildfire smoke on air quality, health, and CO2 emissions.[52]

There is no consensus regarding the proper quantification of wildfire smoke impact on overall air quality and any specific resultant health impacts, to the extent they exist. This is supported by MGRA's comment about the revision on its own quantification attempt: "SDG&E's wildfire smoke risk estimates underestimate the overall wildfire smoke risk and this was confirmed by consultation with domain experts who stated that the MGRA calculations themselves are very likely underestimates."[53] SDG&E will continue to review scientific, academic, and governmental research regarding the impacts of wildfire smoke. But, at this time, SDG&E does not believe that any other wildfire smoke-related consequences should be considered for risk modeling purposes, nor should any ill-founded assumptions inform SDG&E's investment decisions.

SDG&E's risk spend efficiency modeling for investment aims to design and improve its infrastructure to prevent utility-ignited fires and reduce their potential size and impact on its customers. By prioritizing the reduction and mitigation of utility-related ignitions in its risk models, SDG&E achieves MGRAs goal of reducing any corresponding smoke impacts, thus secondary smoke impacts should not currently be included in its risk models or adopted in this GRC. SDG&E notes that the inclusion of wildfire smoke in its risk analysis would likely serve to only *increase* the consequences of catastrophic fire and would likely lead SDG&E's models to indicate the need for additional undergrounding investment, which seems to contradict MGRA's overall recommendations and conclusion.

At this moment, SDG&E strongly believes that it is prudent to continue monitoring ongoing research performed by academia, industry leaders, and government agencies (i.e., the California Air Resources Board (CARB), the U.S. Forest Service, CALFIRE) on wildfire smoke modeling impact quantification. When models are fully developed and agreement is reached, SDG&E will collaborate with Office of Energy Infrastructure Safety, other Investor-Owned Utilities (IOUs), and stakeholders to further evaluate the appropriateness of including the effects of Wildfire Smoke in existing risk models.

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52 Risk Model Working Group presentation, December 14, 2022, attached here as Appendix C.

53 MGRA (Mitchell) at 12:28-13:3.

B. Balancing Accounts

1. WMPBA

SDG&E requests two-way balancing treatment of the wildfire mitigation-related costs described in my direct testimony, subject to specified thresholds. Two parties addressed this request in different ways.

a. TURN

TURN objects to any balancing treatment of wildfire mitigation costs. TURN recommends SDG&E's request for a Wildfire Mitigation Balancing Account (WMBA) be denied on the basis it is inconsistent with Section 8386.4 of the Public Utilities Code. TURN supports retention of the current WMPMA with SDG&E being required to submit all costs incremental to its authorized revenue requirement through an application for a reasonableness review.

TURN's interpretation of Public Utilities Code Section 8386.4 is incorrect and inconsistent with existing Commission precedent—in fact, this specific argument has already been rejected by the Commission.[54] Assembly Bill (AB) 1054 included this statutory provision to address the problem of cost recovery for unanticipated costs incurred to implement the newly implemented WMPs. Because the WMP process was established effective in 2019, with the three-year plan process starting in 2020, the electrical corporations faced the potential for significant costs necessary to mitigate wildfire risk but unaccounted for in their effective rates. To avoid retroactive ratemaking, the Legislature directed the Commission to authorize memorandum accounts "at the time of approval of [the] electrical corporations Wildfire Mitigation Plan."[55] The Legislature directed approval of the memorandum account as a one-time solution to account for the time necessary to align the WMPs with the electrical corporations' GRC forecasts.[56] Section 8386.4 "does not strictly prohibit the establishment of a balancing account for wildfire mitigation activities, as evidenced by the Commission's recent approval of a

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54 *See*, PG&E Test Year 2020 GRC Decision, (D.)20-12-005 at 119-120; Southern California Edison GRC Decision (D.)21-08-036 at 249-250 and Conclusion of Law 100 ("Pub. Util. Code §8386.4 does not prohibit the establishment of a balancing account for wildfire mitigation activities.")

55 Pub. Util. Code §8386.4(a).

56 Per Pub. Util. Code §8386.4(b)(1), the default approach to address wildfire mitigation plan costs is through the general rate case process, electrical corporations may opt in lieu of the GRC to file a separate application at the conclusion of each WMP.

Wildfire Mitigation Plan Balancing Account in PG&E's GRC, but merely provides another pathway for potential cost recovery."[57]

TURN's discussion of PG&E's WMPMA is misplaced in this context, as the PG&E WMPMA addressed by TURN was proposed to address PG&E's wildfire capital expenditures subject to AB 1054's equity return exclusion, and not PG&E's other wildfire-mitigation expenditures to implement its WMP.[58] In fact, the Commission *approved* two-way balancing for PG&E's other system hardening and related costs in that very same decision, because the "expanded mitigation activities and capital projects [] are new and costs are difficult to predict. … A two-way balancing account allows PG&E to spend more than the authorized amount in cases where the authorized forecast is below what is necessary to conduct necessary and important safety-related mitigations against wildfire risks."[59] Two-way balancing of SDG&E's wildfire mitigation expenditures is reasonable for the very same reasons the Commission cited in the case of PG&E.

The Commission has similarly approved balancing treatment for Southern California Edison Company's (SCE) system hardening costs—namely its covered conductor program. Given the ongoing evolution of the wildfire regulatory environment, the constant influx of new data on wildfire science, situational awareness, and climate change, and changing risk assessments, the scope of wildfire mitigation programs remains difficult to predict. While SDG&E continues to build upon its years of experience in this field, the scope and specifics of its covered conductor and strategic undergrounding costs continue to be uncertain; for example, SDG&E continues to realize cost-efficiencies related to undergrounding as its program comes to scale. In the same fashion as PG&E, two-way balancing as proposed by SDG&E "affords the Commission some degree of reasonableness review if expenditures exceed a certain level above the authorized forecast. At the same time, if planned projects are not able to be completed or actual expenditures end up lower than forecast, a two-way WMP[B]A allows [SDG&E] to return unused amounts to ratepayers."[60]

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57 D.21-08-036 at 250.

58 TURN-15 at 20, discussing D.20-12-005 at 127 and conclusion of Law 38.

59 D.20-12-005 at 119-120.

60 *Id*.

Additionally, there is no support for TURN's argument that SDG&E continue to record costs incremental to authorized in a memorandum account, rather than the graduated review process set by the thresholds proposed by SDG&E. Authorizing two-way balancing with reasonable thresholds for recovery via either advice letter or application, depending on the amount, protects ratepayers by allowing the Commission opportunity to review additional incurred costs, SDG&E to recover prudently incurred expenses, and ensures that any undercollection is returned to ratepayers.[61]

TURN's alternative, that *any* incremental costs be reviewed via an application process imposes unnecessary burdens and resource constraints on the Commission, who is capable of assessing the reasonableness of a certain level of additional expenditures via an expedited advice letter process. Like Cal Advocates, TURN appears to express concern regarding SDG&E's proposed thresholds.[62] As further discussed below, SDG&E believes its review thresholds are reasonable, but remains open to alternative thresholds to trigger an application for recovery of costs exceeding authorized. As the Commission has already found in SCE's GRC, "the establishment of a two-way balancing account and application review process will accomplish many of the same ratepayer protections as TURN's alternative balancing account plus memorandum account proposal."[63] The same is true for SDG&E's proposal, which the Commission should approve without modification.

b. Cal Advocates

There is a lack of clarity regarding Cal Advocates' position on SDG&E's WMPBA request. Witness Kaur briefly expresses opposition to the creation of a WMPBA and maintains that "O&M and capital costs associated with the implementation of the WMP should continue to be recorded to the WMPMA."[64] But Kaur notes that "[t]he cost of WMP activities (e.g. system hardening and undergrounding) is substantial and can shift significantly with even the slightest modifications to project scope and details."[65] While Kaur advocates for a process to "assess the reasonableness and effectiveness of WMP spending before the costs are passed down to

[61] D.21-08-036 at 249.

[62] TURN-15 at 20:10-12.

[63] D.21-08-036 at 250.

[64] Cal Advocates-07 at 26:13-14.

[65] *Id*. at lines 17-19.

ratepayers," that is precisely what is being addressed through this proceeding.[66] And as addressed above, SDG&E's proposed thresholds for review of any costs exceeding authorized allows Cal Advocates and other stakeholders to assess whether "SDG&E's WMP spending is reasonable, effective, and presents a net benefit to ratepayers."[67]

SDG&E agrees generally with Witness Hunter, who requests that the Commission approve two-way balancing treatment for SDG&E's Wildfire Mitigation Program, subject to thresholds for a reasonableness review.[68] Witness Hunter notes that the Commission has established a precedent adopting two-way balancing treatment for important but uncertain wildfire mitigation activities, which reduces risk for both customers and the utility investors. Because of the nuanced analysis, which addresses and encourages the adoption of mechanisms previously approved by the Commission, SDG&E assumes that Cal Advocates' general recommendation regarding the WMPBA is that the two-way balancing account should be approved, but with modified reasonableness review thresholds.

While TURN recommends an application process for recovery of any costs above authorized, Cal Advocates argues in favor of "an application for reasonableness review of any costs in excess of 110% of the capital expenditure amounts authorized in this decision. Any undercollection that is less than 110% of authorized in this proceeding, as well as the refund of any overcollection, should be filed via a Tier 2 advice letter."[69] SDG&E acknowledges that Cal Advocates' approach is consistent with the process the Commission authorized for SCE's covered conductor investments and is largely similar to that authorized for PG&E, who is required to file an application for any undercollection in excess of 115% of authorized, and a Tier 2 advice letter in the alternative.[70] While SDG&E maintains that its recommended process for review and approval of both under and overcollections in the proposed WMPBA are

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66 Witness Kaur's assessment appears to lack a key element, which is the acknowledgment that the Commission will authorize a WMP-related revenue requirement in this proceeding, so tracking all costs in a memorandum account would be inconsistent with typical ratemaking approaches upon such authorization.

67 *Id*. at lines 20-21.

68 Cal Advocates-20 at 20:15-19.

69 *Id*. at lines 17-21.

70 D.20-12-005 at 121.

reasonable, it is open to considering alternative thresholds for reasonableness reviews of undercollected wildfire mitigation costs.

2. VMBA

TURN does not take a position regarding SDG&E's expansion of the existing Tree Trimming Balancing Account (TTBA) to include additional vegetation management activities in the Vegetation Management Balancing Account (VMBA). But TURN recommends that, either way, the Commission should modify treatment of SDG&E's vegetation management activities into a one-way balancing account, with a companion Vegetation Management Memorandum Account (VMMA) to record above authorized spending, subject to reasonableness review in a later application.[71] No other parties specifically address or contest SDG&E's request for two-way balancing of vegetation management activities.

First, consistent with SCE, the Commission should approve consolidation of SDG&E's vegetation management activities into a single balancing account, the VMBA. As the Commission has previously found with respect to PG&E, "consolidating similar activities into one balancing account promotes efficiency in tracking and reviewing costs."[72] Since the establishment of a two-way TTBA, SDG&E has established itself as a good steward of its vegetation management activities. Moreover, circumstances during the prior GRC cycle have demonstrated the need for, and efficiency of, flexibility to respond to increasing and decreasing vegetation management needs and costs. For instance, two-way balancing treatment allowed SDG&E to maintain consistent tree-trimming operations after the passage of Senate Bill (SB) 247, which increased prevailing wages for tree-trimming contractors, and to pursue enhanced vegetation management efforts—such as additional audits and inspections, as well as enhanced clearances on high risk species—to address wildfire risk. As is the case with the other California Investor-Owned Utilities, "it is critical that the Commission not place a cap on vegetation management expenditures given the importance of these activities to mitigating wildfire risk, at a time when the associated costs are uncertain and outside of [SDG&E's] control."[73]

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71 TURN-15 at 20.

72 D.20-12-005 at 67.

73 D.21-08-036 at 185.

The current TTBA allows SDG&E to manage and maintain routine tree trim maintenance activities and quickly mitigate any emergencies related to vegetation conflicts providing its customers safe and reliable services. SDG&E continues to experience the impacts of climate change, environmental mitigations, tree mortality, vegetation growth, agency constraints, increased fire prevention measures, competing resource needs for Certified Arborist and Line Clearance Qualified Tree-trimmers, and the International Brotherhood of Electrical Workers (IBEW) Union Labor agreements. These variables make it very difficult to accurately forecast annual vegetation management costs. Continued two-way balancing of these expenses affords appropriate protection against the uncertainties and risks that impact vegetation management costs and are often outside SDG&E's control. These same challenges apply to SDG&E's Pole Brushing and Fuels Management operations, which help prevent vegetation caused outages, ignitions, and catastrophic wildland fires. Adding these activities to the two-way balancing account is appropriate and no party contests such an approach.

Further, as demonstrated over the previous GRC cycle, two-way balancing of these costs protects customers in that it provides a mechanism for the Commission and stakeholders to review undercollections prior to recovery and for SDG&E to return any overcollection of funds. Because of various changed circumstances, such as the passage of SB 247 and to address wildfire risk, SDG&E has filed applications for recovery of tree trimming related undercollections on two occasions to date. For 2019 undercollections, the Commission found that the majority of SDG&E's incremental expenditures were reasonable and prudent.[74] Consistent with existing Commission precedent, the Commission should find SDG&E's proposal to expand the TTBA to cover all vegetation management activities reasonable and accept it without modification.

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[74] 2020-2021 TTBA undercollections are the subject of a pending Commission application, A.22-12-008.

IV. REBUTTAL TO PARTIES' O&M PROPOSALS

A. Non-Shared Services O&M

Table JW-4

TOTAL O&M - Constant 2021 ($000)			
	Base Year 2021	**Test Year 2024**	**Change**
SDG&E	**168,436**	**168,955**	**519**
CAL ADVOCATES	**168,436**	**162,468**	**(5,968)**

1. 1WM003 - Standby Power Programs

a. Cal Advocates

Cal Advocates takes issue with the Test Year O&M forecast for Standby Power Programs within 1WM003. Cal Advocates uses a methodology of utilizing 2021 data to calculate the average unit costs for the program in Tier 3 and Tier 2, then applying that unit cost to 2024 units.[75] This results in a reduction of $1.148 million. Cal Advocates provides no justification or rationale for applying 2021 costs and the Commission should not accept the recommended reduction.

Cal Advocates methodology does not capture the cost drivers impacting this program since 2021. SDG&E's Standby Power Programs have continued to evolve since their inception. These changes have resulted in a more fully streamlined customer experience, as well as increased costs from vendors to provide these services. As discussed in my direct testimony, "SDG&E's Standby Power Programs has an upward driver of $1,416,000 in forecasted 2024 costs compared to 2021. The cost increase is driven by the shift to sustainable power offerings such as batteries in lieu of the traditional propane generators."[76]

In addition to increases in the cost of equipment, the implementation of the program includes contract labor for installation and quality control. These costs have increased over time in line with broader inflation and other factors. Additionally, the 2024 request for this program includes fixed costs for administrative requirements, marketing, reporting, and additional support tasks that do not scale with the number of units being installed. For these reasons, the

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75 Cal Advocates-07 at 14:6-14.

76 Ex. SDGE-13-2R at JTW-54

Commission should approve SDG&E's original proposed expenditures of $10.35 million without modification.

2. 1WM003 - Resiliency Assistance Programs

a. Cal Advocates

Cal Advocates takes issue with SDG&E's forecast for Resiliency Assistance Programs within 1WM003. Cal Advocates uses a methodology of utilizing 2021 data to calculate the average unit costs for the program in Tier 3 and Tier 2, then applying that unit cost to 2024 units.[77] This results in a reduction of $0.562 million. Again, the application of 2021 costs is unjustified and without support, and should thus be rejected.

Cal Advocates recommended reductions do not capture the cost drivers impacting the program since 2021. SDG&E is working with its third-party implementer on plans to make several robust enhancements to the customer rebate process in 2023 and 2024. These enhancements result in some additional cost but will lead to improved online application and coupon request portals, a more streamlined process for customers, and will allow customers to have more options in how to receive their rebates. Further, third-party contract and labor costs are expected to rise each year due to the general increase in overall costs experienced nationwide. Finally, customer participation can vary widely due to the weather and fire threat levels, so adequate funding is needed to ensure all interested customers have the opportunity to receive a rebate if they have need for backup power to prepare for fire season. Therefore, SDG&E requests that the original program cost of $1.829 million be approved.

3. 1WM005 - Fuels Management

a. Cal Advocates

Cal Advocates takes issue with the Test Year O&M forecast for Fuels Management within 1WM005. Cal Advocates states that the basis for its TY O&M recommendation is a methodology of utilizing 2021 data to calculate the average unit costs for the program in Tier 3 and Tier 2, then applying that unit cost to 2024 units. The formula Cal Advocates used in its methodology was based on $4.416 million actual spend and a completed unit count of 463 poles which results in a reduction of $1.028 million.

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[77] *Id*. at 14:15-22.

SDG&E disagrees with Cal Advocates based on its assumption of the work volume in the test year, and that Cal Advocates TY O&M recommendation does not adequately reflect the changes described in my direct testimony and workpapers, which Cal Advocates does not specifically discuss or object to.

Vegetation Management began administering the fuels management program in 2021 with a target of completing 500 poles annually. SDG&E completed 463 poles in the base year. SDG&E was able to complete its target plan of 500 poles in 2022 and plans to meet this target in 2023 and base year 2024. Cal Advocates methodology of work volume and unit cost, therefore, fails to consider the additional poles SDG&E plans to complete under this program. While SDG&E objects to applying 2021 unit costs to 2024 activities for several reasons, even assuming Cal Advocates unit cost average of $9,537, the total cost of 500 poles is $4.768 million.

As provided in testimony, the Fuels Management Program consists of three activities: fuels treatment, vegetation abatement, and fuels reduction grants. New initiatives and programs have been implemented as part of SDG&E's Wildfire Mitigation Plan, and these enhancements are not captured in historical costs. For instance, the fuels reduction community grants continue to develop as additional partnerships grow between SDG&E and entities such as local and regional tribes.

SDG&E forecasts an increased use of fuels reduction grants to promote community engagement and lead defensible space efforts. These grants are consistent with SDG&E's 2022 Wildfire Mitigation Plan (WMP) Update initiatives. Further, contract labor costs to perform mechanical vegetation management in SDG&E rights of way, as well as liability insurance coverage are forecasted to increase. SDG&E forecasts that this program will also include third-party engagement to study the methodology and impacts of the effectiveness of fuels treatment, and research potential enhancements to promote sustainability. The cost associated with the fuels reduction grants in base year was $1.00 million, and forecasted to be $1.50 million in test year 2024; these costs are in addition to the fuels treatment activity. Therefore, the Commission should approve SDG&E's recommendation of $6.274 million.

4. 1WM005 - Pole Brushing

a. Cal Advocates

Cal Advocates takes issue with the Test Year O&M forecast for Pole Brushing within 1WM005. Cal Advocates assumes that annual costs for pole brushing will remain static through

2024, applying 2021 data to calculate the average unit costs the program in Tier 3 and Tier 2, then applying that unit cost to 2024 units. This methodology results in a decrease of $1.658 million.

SDG&E disagrees with Cal Advocates' approach because it assumes no annual increases to labor costs and does not represent the program changes presented in my direct testimony and associated workpapers. SDG&E is requesting incremental activity costs, which Cal Advocates does not specifically discuss or object to. The primary driver for pole brushing cost increases relates to contractor costs, including but not limited to contracted services, contractor's excess liability insurance coverage, and related pre-inspection and audit. Therefore, SDG&E recommends the Commission authorize SDG&E's original proposal of $7.027 million associated with this activity.

5. 1WM005.001 - Tree Trimming (HFTD)

a. Cal Advocates

Cal Advocates disputes SDG&E's Test Year O&M forecast for Tree Trimming in the HFTD. Cal Advocates uses a methodology of utilizing 2021 data to calculate the average unit costs for the program in Tier 3 and Tier 2, then applying that same unit cost to 2024 units, resulting in a $0.620 million reduction.[78] Cal Advocates does not specifically object to the scope and activities of SDG&E's tree trimming program.

The Commission should not adopt Cal Advocates' methodology as it does not capture the changes from 2021 to present as described in my testimony and workpapers. As stated in my direct testimony, cost increases over base year are largely tied to forecasted increases in labor costs, including increased rates as a result of contract negotiations, inflationary and labor market pressures, and increased liability insurance costs for contractors.[79] SDG&E base year costs appropriately includes the substantial labor cost pressures associated with the implementation of SB 247 in addition to the amount of increased work because of improvements made and documented within the WMP.

78 CA-07 (Kaur) at 17:17-22.

79 Ex. SDG&E-13-2R at 73:18-20.

6. 1WM005.001 - Tree Trimming (Non-HFTD)

a. Cal Advocates

Cal Advocates takes issue with the Test Year O&M forecast for Tree Trimming in the non-HFTD. Cal Advocates uses a methodology of utilizing 2021 data to calculate the average unit costs for the program in Tier 3 and Tier 2, then applying that same unit cost to 2024 units.[80]

As with tree trimming in the HFTD, The Commission should not adopt Cal Advocates' methodology as it does not capture the changes from 2021 to present as described in my testimony and workpapers. As stated in my direct testimony, cost increases over base year are largely tied to forecasted increases in labor costs, including increased rates as a result of contract negotiations, inflationary and labor market pressures, and increased liability insurance costs for contractors.[81] SDG&E base year costs appropriately includes the substantial labor cost pressures associated with the implementation of SB 247 in addition to increased activities to address wildfire mitigation.

In addition, Cal Advocates recommendation for a $5.455 million reduction is based on a flawed premise, namely an error in the number of forecasted units. SDG&E stipulates that for forecasting purposes, there is no difference in its cost per unit between the HFTD and non-HFTD. While preparing this rebuttal, however, SDG&E discovered the forecasted 2024 unit counts provided in workpapers was under-represented. The total, combined unit count for HFTD and non-HFTD for test year 2024 should equal the unit count provided for year 2023 (491,822).[82] Adjusting the 2024 units in the HFTD brings the total to 273,000 and the non-HFTD to 218,822, a 55.5% and 45.5% split respectively. Using Cal Advocates' unit cost methodology, this corrected unit count would result in a forecasted spend of $15.318 million, which is only a $2.837 million reduction relative to SDG&E's forecast. While SDG&E believes its entire non-HFTD forecast is reasonable and justified, SDG&E requests that the Commission note this error.

[80] CA-07 (Kaur) at 18:5-9.

[81] Ex. SDG&E-13-2R at 73:18-20.

[82] Ex. SDG&E-13-WP-2R at 107.

V. REBUTTAL TO PARTIES' CAPITAL PROPOSALS

Table JW-5

TOTAL CAPITAL - Constant 2021 ($000)		
	2024	**Difference**
SDG&E	**518,507**	**-**
CAL ADVOCATES	**457,337**[83]	**(61,170)**
TURN	**318,207**	**(200,300)**

A. 192460 - Strategic Undergrounding

1. Cal Advocates

Cal Advocates states that it agrees with the need to harden unhardened conductors, especially those with high equipment risks and in areas of high wildfire risks[84] but proposes a novel approach, including a per-mile cost recovery and cost cap for undergrounding based upon the risk profile of the circuit being undergrounded. Cal Advocates acknowledges that "system hardening lowers the chance of utility equipment sparking ignitions, thereby enhancing utility safety."[85] While SDG&E and Cal Advocates agree that hardening, including undergrounding, should occur in unhardened and high wildfire risk areas, the Commission should reject Cal Advocates' unprecedented approach in recommending a cost cap for work it acknowledges is reasonable. This approach implies that shareholders should absorb costs determined to be just and reasonable by the Commission, a violation of the regulatory compact and inconsistent with ratemaking principles.

At the outset, contrary to Cal Advocates' testimony, SDG&E has not undergrounded 4,072 circuit miles within Tier 3 and 2,100 circuit miles within Tier 2 of the HFTD in response to the 2007 wildfires.[86] SDG&E embraced an industry-leading approach to wildfire mitigation after those devastating events, but Cal Advocates misinterprets a data request response that

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83 Cal Advocates reductions to workpapers 20285 – Overhead System Covered Conductor and 19246 – Strategic Undergrounding presented in CA-07 utilize the costs presented in the original testimony. SDG&E has since revised these costs in exhibit SDGE-13-2R. To calculate Cal Advocates 2024 recommended costs, SDG&E utilized the percent reduction Cal Advocates recommended and applied this percent reduction to the revised costs.

84 CA-21 (Li) at 23:5-7.

85 *Id*. at 5:16-17.

86 *Id*. at 6:7-10.

requested total miles of undergrounded infrastructure in the HFTD as infrastructure undergrounded in response to wildfire threat. SDG&E's early wildfire mitigation hardening efforts were focused on overhead hardening of risky bare wire segments; much of the undergrounded infrastructure described by Cal Advocates was likely the result of initial or new construction.

Cal Advocates does not appear to object to SDG&E's scope of the circuits selected for undergrounding,[87] and agrees overall with SDG&E's approach that "it is critical that SDG&E optimize its hardening in terms of risk reduction and cost considerations."[88] As shown in the chart below, to the extent practical, SDG&E prioritizes hardening of the riskiest segments first—the majority of segments proposed for hardening during this GRC cycle are in the highest levels of risk.[89] Cal Advocates also notes that, per SDG&E's WiNGS 2.0 model, from 2025 to 2027, 96% of SDG&E's hardening efforts will occur within the top 20 percent of the riskiest overhead segments.[90] Conversely, less than one percent of SDG&E's hardening will address the bottom 60% of risk.[91]

[87] *Id*. at 8-9 ("Cal Advocates cannot reach a determination on whether SDG&E has reached satisfactorily safe service levels.")

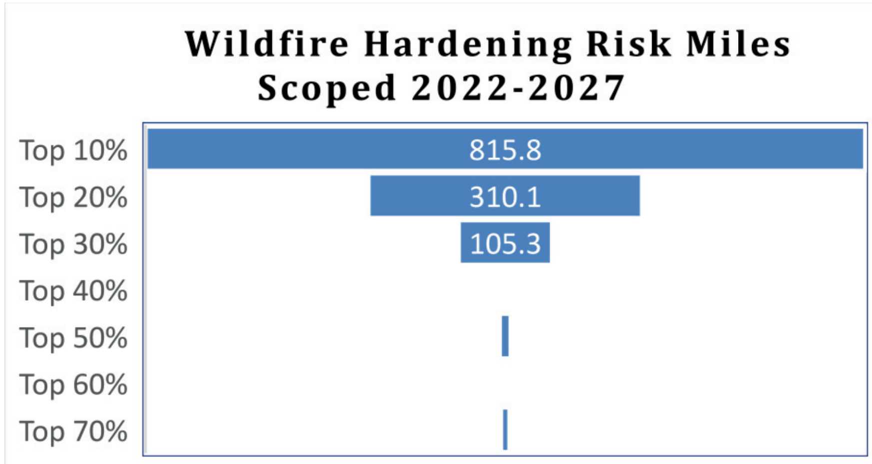
[88] *Id*. at 12.

[89] The table summarizes all of SDG&E's scoped hardening activities, including both covered conductor and undergrounding. SDG&E also disputes Cal Advocates' inclusion of Energy Safety's "previously raised concerns that SDG&E may not have prioritized the riskiest segments [for hardening in 2020]." (Id. at 18). First, past hardening efforts are not within the scope of my testimony. But more importantly, SDG&E rebutted Energy Safety's findings addressing its 2020 WMP hardening efforts, noting significant errors in how Energy Safety categorized areas of risk.

[90] Cal Advocates-21 at 21 (Table 21-3).

[91] *Id*.

Figure JW-3, Wildfire Hardening Scope (2022-2027) by Riskiest Segments[92]



Cal Advocates solution that "the Commission should authorize higher unit cost caps for SDG&E's hardening on riskier power lines"[93] and impose a per mile cost recovery and cost cap on the per-mile unit costs for undergrounding based on the risk profile of the circuit[94] is ill advised. This approach ultimately punishes SDG&E and its shareholders for necessary hardening work that is consistent with its Wildfire Mitigation Plan, state directives to harden infrastructure, and overall community safety. Further, adopting such a cost cap serves to disincentivize the very investment AB 1054 found necessary to promote wildfire mitigation and infrastructure safety.[95]

The goals of Cal Advocates' recommended cost cap approach can be achieved through existing conventional ratemaking tools, including SDG&E's current proposal for a two-way balancing account for wildfire mitigation activities. First, by approving a revenue requirement associated with this request, the Commission already caps "the total capital expenditure on

[92] SDG&E notes that the work scoped for segments in the lower risk areas generally represents legacy work scoped prior to implementation and operation of SDG&E's WiNGS-Planning model and in flight for construction. These miles may be scoped to address downstream PSPS based on circuit-segment dependency. Additional information is available in SDG&E's 2023-2025 WMP at Section 7.2.3.1.2 (pages 103-104).

[93] *Id*. at 13.

[94] CA-21 (Li) at 1:8-23.

[95] Assembly Bill 1054, Section 1 ("Electrical corporation[s] need capital to fund ongoing operations and make new investments to promote safety, reliability, and California's clean energy mandates and ratepayers benefit from low utility capital costs in the form of reduced rates.").

system hardening for this GRC period."[96] Additionally, two-way balancing "allows flexibility for SDG&E to reallocate money within its system hardening budget, which promotes efficiency and public safety by allowing SDG&E to harden more power lines than anticipated if the company (1) completes hardening work at lower unit costs than currently forecast, (2) hardens at a faster rate than forecast, (3) reallocates money from undergrounding to covered conductors, or (4) does all of the above."[97] Ironically, the two way balancing approach recommended by SDG&E, and supported by Cal Advocates' Post Test Year Witness, best achieves these very goals.[98]

Additionally, the Wildfire Mitigation Plan process affords Cal Advocates ongoing transparency into the risk profile of circuits scoped for hardening on an annual basis. As Cal Advocates notes, "SDG&E has already stated that it will harden the riskiest circuit segments, … [and] this targeting is also evident in the risk distribution of the power lines which SDG&E plans on hardening during this GRC period."[99] Cal Advocates has various methods, including the quarterly data updates, geographic information systems (GIS) maps, and Annual Reports on Compliance to confirm that SDG&E is delivering on its commitment to prioritize hardening on the riskiest circuit segments.

Cal Advocates cost cap proposes a unit cost recovery of up to $2.34 million for the top 20% riskiest circuits, $1.87 million for the next 20% riskiest circuits, and $1.40 million for the bottom 60% riskiest circuits.[100] The $2.34 million per-mile unit cost of undergrounding equates to SDG&E's current forecast for the average cost of its undergrounding program. However, costs for undergrounding are variable and can be influenced by factors including but not limited to: material and labor costs, subsurface conditions, and easements and permitting. This cost variance is not influenced by the risk profile of the circuit. Some undergrounding projects may cost more than $2.34 million per mile, while others may cost less. Each of SDG&E's hardening projects scoped through this GRC cycle are beneficial and necessary to reduce the risk of wildfire and

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[96] CA-21 (Li) at 4:9-10. SDG&E notes that it is prohibited from diverting funds authorized for wildfire mitigation activities to other investments outside of the plan. *See*, Pub. Util. Code §8386.3(d).

[97] CA-21 (Li) at 4-5.

[98] CA-20 (Hunter) at 20:15-17

[99] CA-21 (Li) at 18:12-19.

[100] CA-21 (Li) at 3.

impacts of PSPS on customers. Full recovery of these projects should be authorized, with any variable costs addressed via SDG&E's proposed two-way balancing mechanism.

2. TURN

TURN takes issue with the capital forecast for Strategic Undergrounding. TURN proposes a reduction in Strategic Undergrounding from 150 miles to 35 miles in 2024.[101] This proposal is based upon TURN's inherently flawed alternative risk modeling proposal, which is discussed in Section III above. Moreover, TURN should not dilute SDG&E's proposed wildfire risk reduction by extrapolating it to overall statewide risk reduction. TURN claims its proposal represents a "less than 1 percent impact compared with total *statewide* wildfire risk."[102] Hidden in the footnotes, however, is the truth that TURN's proposal in reality reduces "12 percent less [wildfire] risk than SDG&E's,"[103] exposing our customers, community, and employees to a 12% higher likelihood of a catastrophic fire. Not only is that exposure unreasonable, it is inconsistent with SDG&E's WMP, the intent of AB 1054, and regulatory mandates from the Office of Energy Safety to "ensure fewer wildfires stem from utility infrastructure" and "build toward sustained, long-term activities that are required to minimize the impact of wildfires not just during the next fire season, but for many seasons to come."[104]

Energy Safety has challenged SDG&E to "ultimately achieve the elimination of utility-caused catastrophic wildfires in California," and reduction of wildfire risk is a standard by which SDG&E's WMP compliance is assessed.[105] TURN simply disregards these mandates, ignores the corresponding directives to reduce PSPS impacts on customers, and provides an alternative approach that offers customers higher risk in exchange for lower costs. TURN's proposal is based on a fundamentally flawed premise, that "residential ratepayers should *never* pay for undergrounding as a PSPS mitigation strategy."[106] TURN admittedly examines the benefits of

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101 TURN-08 (Borden) at 4, Table 1.

102 *Id*. at 2:26-27.

103 *Id*. at 2, fn. 5.

104 *Utility Wildfire Mitigation Strategy and Roadmap for the Wildfire Safety Division*, Appendix 2 at 3, Office of Energy Infrastructure Safety. Available at https://energysafety.ca.gov/wp-content/uploads/docs/strategic-roadmap/final_appendix_2_visionandobjectives_wsd.pdf.

105 *SDG&E Annual Report on Compliance for San Diego Gas & Electric's 2020 Wildfire Mitigation Plan*, Office of Energy Infrastructure Safety, at 68-69 (January 2023).

106 TURN-08 at 28:3-4.

undergrounding by removing PSPS risk reduction from the calculation.[107] Starting from this premise, their data is tailored to suit the conclusion.

Moreover, TURN's approach is fundamentally inconsistent with TURN's past position on PSPS reduction. As MGRA notes, TURN previously stated that it "strongly believes that de energization must be used as a tactic of last resort, and it *should not be used as a long-term mitigation strategy*."[108] Adopting TURN's approach would establish PSPS as a long-term and indefinite wildfire mitigation strategy for overhead circuits.

While SDG&E's strategic undergrounding scope is based on wildfire risk, with PSPS reduction as an added benefit, the Commission should disregard TURN's recommendations as inconsistent with years of precedent, stakeholder requests to reduce PSPS impacts, and overall safety. Contrary to TURN's analysis, SDG&E's risk mitigation approach and its WiNGS-Planning model recommend mitigations based on *wildfire* risk. As discussed in the rebuttal to Cal Advocates on this issue, approximately 96% of SDG&E's hardening from 2025-2027 is targeted at the top 10% of riskiest wildfire circuits.[109] That said, PSPS risk reduction can only be achieved at scale through strategic undergrounding of circuits. Covered conductor may lessen the impacts of PSPS during some wind events, but SDG&E must continue to consider PSPS as a wildfire mitigation for covered conductor circuits. Further, any circuit only partially hardened will achieve no PSPS reduction whatsoever.

As discussed above in Section III, SDG&E believes that TURN's risk modeling approach is inherently flawed and should be disregarded. Overall, TURN's approach will result in less wildfire risk reduction and more PSPS impacts to customers than SDG&E's proposal. For these reasons, SDG&E requests that its forecasted scope of work and associated costs be adopted as presented and TURN's proposal be denied.

3. MGRA

While MGRA acknowledges that "undergrounding provides the greatest protection against wildfire and power shutoff, and from this standpoint improves public safety better than

[107] *Id*. at 33:8-10.

[108] MGRA at 76:3-5, citing R.18-12-005; Mussey Grade Road Alliance Phase I De-Energization Reply Comments (April 2, 2019) at 7 (emphasis added).

[109] TURN offers Table 4, comparing wildfire risk rank and PSPS risk rank by circuit, but fails to tie this chart to any hardening proposed for this GRC cycle. TURN-08 at 24-25.

any mitigation,"[110] it takes issue with the capital forecast for Strategic Undergrounding. MGRA proposes several alternatives to SDG&E's risk modeling that inform capital investments for both undergrounding and covered conductor.[111] These items are addressed in Section III above. While MGRA does not offer a specific proposal for SDG&E's grid hardening initiatives, it does recommend that SDG&E's proposed hardening plan not be approved in its current form.[112] MGRA requests that additional analysis be performed before a decision is made.

SDG&E disagrees with MGRA's request that its current grid hardening proposal be denied pending further analysis. SDG&E's grid hardening proposal is a risk-informed approach to reducing the risk of wildfire and the impacts of PSPS based on analysis of the specific risks associated with each of its circuit segments within the HFTD. SDG&E continues to refine and improve its risk modeling, but has provided sufficient justification of its current proposal, with additional flexibility afforded by approval of a two-way balancing account.

Through the WiNGS-Planning model, SDG&E is targeting its grid hardening plan to the areas of highest risk and includes full hardening of each segment. The full segment hardening ensures better wildfire risk and PSPS risk reduction by having a consistent technology (covered conductor or underground) for the full circuit segment.   Absent the full segment and consistent technology approach, the hardened segments would only be as hardened as the technology with the lowest threshold for wind impacts. The current grid hardening plan will reduce the risk of wildfire by approximately 80% by 2032 and reduce the risks of PSPS to those customers most frequently impacted. SDG&E therefore recommends that its current grid hardening plan, including undergrounding, be approved as presented.

4. SBUA

SBUA takes issue with the capital forecast for Strategic Undergrounding. SBUA states that an alternative to undergrounding is to shift rural service to microgrids during high wildfire risk periods.[113] SBUA points out that SDG&E has installed microgrids to address wildfire risks,[114] but SDG&E's current microgrid programs are only considered as a mitigation against

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110 MGRA at 76:25-26.

111 MGRA (Mitchell) at 81-82.

112 *Id*. at 81:10-11.

113 SBUA (McCann/Moss) at 17:3-4.

114 Id at 15:14-16.

the impacts of PSPS. SBUA also incorrectly assumes that this approach of targeting areas frequently impacted by PSPS can be scaled more broadly across the HFTD.

SBUA analyzes the use of both community-scale microgrids and residential scale microgrids. While SBUA's intentions may be good, these options are simply not feasible to be implemented across the HFTD and would often be ineffective. Community-scale microgrids are currently being proposed within Ex. SDG&E-13-2R.[115] These microgrids may be capable of keeping up to approximately 200 residential customers and some essential customers such as fire stations and community centers energized during a PSPS, event but are not a feasible option for continued usage across the entire fire season, which can last for months in the HFTD.

SBUA ignores the fact that, to reduce the risk of wildfire, the distribution circuits which are connected to these microgrids would also have to be undergrounded to stay safely energized during high-wind or extreme fire potential weather. It is not the energy source that causes the wildfire risk, the energized overhead electric infrastructure is the risk to be mitigated. It does not matter if the lines are energized from SDG&E's traditional sources or from a community microgrid if an ignition source remains overhead. SBUA does not take this fact, or the costs associated with undergrounding these circuits, into consideration when developing their assessment. In reality, SBUA's recommendation would supplement SDG&E's recommended approach to undergrounding, resulting in additional costs.

Therefore, SBUA's statement that community microgrids have the potential to save 70% to 85% over the costs of undergrounding are incorrect.[116] SDG&E utilizes microgrids with some associated undergrounding to mitigate the impacts of PSPS for critical customers and frequently impacted customers. However, this is not a reasonable alternative to undergrounding or other grid hardening measures for reducing the risk of wildfire at scale.

SBUA also proposes the use of residential microgrids to reduce the risk of wildfire.[117] As is the issue with community microgrids, unless the energized overhead electric infrastructure is undergrounded, the wildfire risk remains—as does the risk of PSPS for those circuits. Therefore, in order for residential microgrids to effectively reduce the risk of wildfire, the connected

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[115] Ex. SDG&E-13-2R at 124.

[116] SBUA (McCann/Moss) at 15:11-13.

[117] *See generally,* SBUA (McCann/Moss).

overhead electric infrastructure still subjected to weather impacts would need to be safely isolated during the times of high wildfire risk, which in the HFTD could be months at a time. This brings about several other issues with residential microgrids, including:

1. Design and capacity: Residential microgrids are designed to provide power to a single business or residence. These residences or businesses will have varying load requirements. SDG&E has over 180,000 customers within the HFTD, and microgrids would have to be designed and sized individually for each of these customers. Additionally, not all customers will have the available roof space or ground space to install sufficient generation for their needs.

2. Reliability: SDG&E's distribution network allows for multiple sources to be able to energize a circuit or segment of a circuit. A residential microgrid does not have ties to other sources, and if the microgrid fails or runs out of power the customer remains deenergized until the issue is resolved, which may be a prolonged outage.

3. Maintenance: SDG&E's distribution network is inspected, monitored, and maintained by trained professionals to ensure reliability. However, a residential microgrid requires the customer to maintain and service the system, which may be difficult for the average customer who does not have the expertise or resources to do so. It is worth noting the need to replace a SPS system approximately after 25 years of service as compared to the 45-50 years of service for grid assets.

This proposal would not be able to be implemented in a reasonable amount of time which would prolong the amount of time the wildfire risk remains present. In order to safely de-energize and isolate existing overhead infrastructure; all customers on a circuit segment would need to have their microgrid system installed, connected, and operational. If just one customer on a circuit segment either does not agree or is unable to have a microgrid installed at their residence, the existing infrastructure would need to remain energized and the wildfire and PSPS risk would not be mitigated. SBUA provides no data that all customers within the HFTD are both willing and able to be served by these microgrid proposals, what the timeline would be for implementation of these projects, or the cost of such a large undertaking involving so many stakeholders.

For these reasons, SDG&E does not believe that residential or community microgrids can be considered a reasonable alternative to grid hardening to reduce the risk of wildfire. SDG&E recommends that its current proposal is the most effective and reasonable means of reducing the risk of wildfire and PSPS, and the Commission should adopt it without modification.

5. PCF

PCF takes issue with the capital forecast for Strategic Undergrounding. PCF states that an alternative to undergrounding is to install solar-plus-storage (SPS) facilities for each HFTD Tier 3 customer to reduce the risk of wildfire.[118] But SDG&E's current Standby Power Programs are only considered as a mitigation against the impacts of PSPS. PCF incorrectly assumes that the costs associated with the Standby Power Programs represent SPS systems that are capable of keeping customers energized for prolonged periods of time, and that this program could be scaled effectively across the HFTD Tier 3 to reduce wildfire risk.[119]

Similar to the rebuttal of SBUA's proposal above, unless the energized overhead electric infrastructure is undergrounded, the wildfire risk remains. Therefore, in order for SPS systems to effectively reduce the risk of wildfire, the connected overhead electric infrastructure still subjected to weather impacts would need to be safely isolated during the times of high wildfire risk, which in the HFTD could be months at a time. PCF incorrectly utilizes cost estimates from SDG&E's Standby Power Programs, which are only designed to keep customers energized during a short duration PSPS event. Therefore, PCF's cost estimates are unreasonable and understate the cost to provide off-grid solutions to all HFTD Tier 3 Customers. SDG&E expects that the cost of an SPS able to keep customers reliably energized for prolonged periods of wildfire risk could cost at least three times as much as PCF's quoted costs, and in many cases would be infeasible due to the sheer size of the required batteries and generators required. Several other issues with customer-sited SPS are also present which do not make this a reasonable solution, including:

1. Design and capacity: Residential SPS systems are designed to provide power to a single business or residence. These residences or businesses will have varying load requirements. SDG&E has over 36,000 customers within the HFTD Tier 3, and these SPS

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[118] PCF (Powers) at 3.

[119] PCF (Powers) at 15-16.

systems would have to be designed and sized individually for each of these customers. Additionally, not all customers will have the available roof space or ground space to install sufficient generation for their needs.

2. Reliability: SDG&E's distribution network allows for multiple sources to be able to energize a circuit or segment of a circuit. A residential SPS system does not have ties to other sources, and if the SPS system fails or runs out of power the customer remains deenergized until the issue is resolved, which may be a prolonged outage.

3. Maintenance: SDG&E's distribution network is inspected, monitored, and maintained by trained professionals to ensure reliability. However, a SPS system requires the customer to maintain and service the system, which may be difficult for the average customer who does not have the expertise or resources to do so. The replacement cost of a SPS system after an average of 25 years of service as compared to a typical life of grid assets exceeding 45-50 years needs to be considered.

This proposal would not be able to be implemented in a reasonable amount of time which would prolong the amount of time the wildfire risk remains present. In order to safely de-energize and isolate existing overhead infrastructure, all customers on a circuit segment would need to have their SPS system installed, connected, and operational. If just one customer on a circuit segment either does not agree or is unable to have a SPS system installed at their residence, the existing infrastructure would need to remain energized and the wildfire and PSPS risk would not be mitigated. PCF provides no data that all customers within the HFTD are both willing and able to be served by these SPS systems, what the timeline would be for implementation of these projects, or an accurate cost estimate for such a large undertaking involving so many stakeholders.

For these reasons, SDG&E does not believe that customer-sited SPS can be considered a reasonable alternative to grid hardening in reducing the risk of wildfire. SDG&E recommends that its current proposal is the most effective and reasonable means of reducing the risk of wildfire and PSPS, and the Commission should adopt it without modification.

B. 202850 - Covered Conductor

1. Cal Advocates

Cal Advocates takes issue with the capital forecast for Covered Conductor. Cal Advocates states that it agrees with the need to harden unhardened conductors, especially those with high equipment risks and in areas of high wildfire risks[120] but proposes a per-mile cost cap for covered conductor based upon the risk profile of the circuit being undergrounded.[121]

Like Strategic Undergrounding, SDG&E and Cal Advocates agree that hardening, including covered conductor, should occur in unhardened and high wildfire risk areas. While Cal Advocates does not appear to object to SDG&E's scope of the circuits selected for covered conductor, Cal Advocates does propose a cost cap on the per-mile unit costs for covered conductor based on the risk profile of the circuit.[122] SDG&E disagrees with this cost cap approach, and instead believes its current proposal for a two-way balancing account be adopted for cost recovery associated with wildfire mitigation activities. As discussed in Section V.A, above, the proposed cost cap wrongfully disincentivizes necessary wildfire investment, violates the regulatory compact by requiring shareholders to fund investments otherwise found reasonable by the Commission, and is unnecessary as a means of monitoring SDG&E's prioritization of work in light of existing reporting.

The Commission should reject Cal Advocates' cost cap approach, which can be better implemented via a two-way balancing account for wildfire mitigation activities. Regardless of the risk profile of the circuit, the cost of performing the covered conductor work remains the same. These projects are beneficial and necessary to reduce the risk of wildfire and full recovery of these projects should be authorized.

2. TURN

TURN takes issue with the capital forecast for Covered Conductor. TURN proposes a reduction in Strategic Undergrounding from 150 miles to 35 miles, and a corresponding increase in covered conductor from 40 miles to 100 miles in 2024.[123] This proposal is based upon

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120 CA-21 (Li) at 23:5-7.

121 CA-21 (Li) at 3.

122 *Ibid.*

123 TURN-08 (Borden) at 4, Table 1, Table 2.

TURN's proposed alternative risk modeling proposal, which, as discussed in Section III above is inherently flawed and should not be adopted. Overall, TURN's approach will result in less wildfire risk reduction and more PSPS impacts to customers than SDG&E's proposal. Again, adoption of TURN's approach results in 12 percent additional wildfire risk for SDG&E's service territory versus SDG&E's proposal,[124] and an unquantified amount of additional PSPS risk, which is inconsistent with SDG&E's WMP, Commission and regulatory directives to reduce wildfire risk, and SDG&E's mission to promote the safety of its customers and community.

TURN also proposes a cost cap for covered conductor installation at $800,000 per mile.[125] TURN's analysis for these costs is based on SCE's forecasted costs of their covered conductor program. However, SCE and SDG&E have programmatic and operational differences that do not allow for a direct cost comparison from utility to utility. Some differences include SDG&E utilizing insulation piercing connectors while SCE does not, and the differing mixture of contractor and internal labor being utilized for construction. A full explanation of the cost drivers and methods utilized by the different utilities is included in the Joint IOU Covered Conductor Working Group Report attached to SDG&E's Wildfire Mitigation Plan.[126] SDG&E's covered conductor forecasts are based on a reasonable assessment of scope and equipment necessary to implement this program. Further, assuming the Commission authorizes two-way balancing treatment for wildfire mitigation activities, any savings achieved by additional experience with covered conductor will be returned to customers. For these reasons, SDG&E requests that its forecasted scope of work and associated costs be adopted as presented and TURN's proposal be denied.

3. MGRA

MGRA takes issue with the capital forecast for Covered Conductor. MGRA proposes several alternatives to SDG&E's risk modeling that inform capital investments for both undergrounding and covered conductor.[127] These items are addressed in Section III above. While MGRA does not offer a specific proposal for SDG&E's grid hardening initiatives, it does

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[124] *Id*. at 44, note 84.

[125] TURN-08 (Borden) at 38, lines 26-28.

[126] Joint IOU Covered Conductor Working Group Report, attached here as Appendix D.

[127] MGRA (Mitchell) at 81-82.

recommend that SDG&E's proposed hardening plan not be approved in its current form.[128] MGRA requests that additional analysis be performed before a decision is made.

SDG&E disagrees with MGRA's request that its current grid hardening proposal be denied pending further analysis. SDG&E's grid hardening proposal is a risk-informed approach to reducing the risk of wildfire and the impacts of PSPS based on analysis of the specific risks associated with each of its circuit segments within the HFTD. SDG&E continues to refine and improve its risk modeling, but has provided sufficient justification of its current proposal. Through the WiNGS-Planning model, SDG&E is targeting its grid hardening plan to the areas of highest risk. The current grid hardening plan will reduce the risk of wildfire by approximately 80% by 2032 and reduce the risks of PSPS to those customers most frequently impacted. SDG&E therefore recommends that its current grid hardening plan, including covered conductor, be approved as presented.

C. 202820 - Lightning Arrestor Replacement Program

1. Cal Advocates

Cal Advocates takes issue with capital forecast for the Lightning Arrestor Replacement Program. Cal Advocates utilizes a forecast methodology that calculates a unit cost for lightning arrestor replacements from 2021 cost and unit data.[129] Cal Advocates applies this 2021 unit cost to 2024 units to develop its forecast of $3.2 million, a reduction of $0.357 million from SDG&E's proposed costs.[130]

SDG&E disagrees with Cal Advocates methodology as SDG&E has provided a detailed supplemental workpaper for this program.[131] Cal Advocates does not take issue with any of the costs or units provided in this supplemental workpaper, instead relying on a simplified methodology to derive its 2024 forecast that fails to account for inflation and other factors that have resulted in cost increases since 2021. Therefore, SDG&E's more detailed approach to forecasting lightning arrestor replacement programs should be adopted, and the original proposal of $3.557 million should be approved.

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[128] *Id*. at 81:10-11.

[129] CA-07 (Kaur) at 25:11-13.

[130] *Id*. at 25:5-6.

[131] SDG&E-13-CWP-2R at 161.

D. Post-Test Year Exception

1. Cal Advocates

Cal Advocates recommends a 10% reduction each year in the post-test year of SDG&E's Wildfire Mitigation and Vegetation Management costs[132]. This reduction is consistent with Cal Advocates' proposed reductions to SDG&E's capital programs. SDG&E does not agree with Cal Advocates' reductions to its capital programs, and these are addressed within Sections V.A, V.B and V.C above.

VI. BUSINESS JUSTIFICATIONS

1. Vehicle Additions

TURN takes issue with the Test Year Capital forecast for a Vehicle Additions for related to activities described in my direct testimony. TURN states that SDG&E fails to justify incremental vehicle forecasts.[133] See Exhibits SDG&E-22-R and SDG&E-222 for specific details and discussion related to the cost of these vehicles.

SDG&E disagrees with TURN as included in my testimony and workpapers is the request for three additional vehicles. The first vehicle is in support of an incremental full-time equivalent (FTE) for the Incident Support Team, to advance SDG&E's Incident Command System (ICS) initiative. My testimony justifies the vehicle as follows, "To advance SDG&E's ICS initiative, SDG&E is requesting a full-time resource as well as an incident support command vehicle to respond to and support requests for field-level incidents and mutual assistance deployments. Operating as a central hub for inter-agency coordination, the incident support vehicle functions as a mobile incident command post."[134]

The second vehicle is in support of the Unmanned Aerial System (UAS) Program Expansion. My testimony justifies the vehicle as follows, "SDG&E is proposing the expansion of the UAS program. This request includes a specialized vehicle to travel with and house assets and the acquisition of UAS technology (i.e., drones) to facilitate a scalable and impactful UAS program. This expansion maintains a forward-thinking, safe, and efficient UAS program to meet

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132 CA-20 (Hunter) at 23:3-4.

133 TURN-10 (Jones) at 10:10-14.

134 Ex. SDG&E-13 (Woldemariam) at 42:12-15.

the increasing need for missions to strengthen infrastructural knowledge, situational awareness, and improve electric system reliability."[135]

The third vehicle is in support of an incremental FTE in support of SDG&E's Fire Science and Coordination team. This vehicle is in support of an incremental FTE in support of the Ignition Management Program that coincides with a request of one vehicle addition to the SDG&E Fleet. This FTE is justified as follows, "One new fire coordinator is necessary to assist with improving SDG&E's reporting and investigations of ignitions that occur within the service territory. The Office of Energy Infrastructure Safety has also recently implemented new regulations that significantly expand reporting of ignitions and wildfire threats beyond what was previously in place at the CPUC. Meeting these regulatory requirements requires additional resources and coordination."[136] In general, there is a 1:1 FTE to vehicle ratio for this position as each employee is assigned a vehicle to complete ignition investigations throughout the service territory.

2. Vegetation Management – Work Management

UCAN states that the workpapers for this project do not adequately present justification for the Information Technology (IT) Capital and recommends that the Commission not fund portions of proposed capital project costs, including Vegetation Management – Work Management[137], which would be a reduction of $1.68 million for 2024.[138] UCAN asserts that SDG&E has only provided a cursory justification for these projects and provides no assurance these projects will avoid technological obsolescence. For further discussion of technological obsolescence, please see Ex. SDG&E-225, section III.A.

SDG&E disagrees. As stated in testimony, the purpose of this project is to align with the Field Service Delivery (FSD) goal to build a streamlined technology landscape for the field[139.] Today Vegetation management relies on multiple systems, utilizing the combination Powerworkz and EPOCH for their work management solution, and a homegrown Vegetation Electronic Ticketing System (VETS) for intake of requests and management of communications

[135] Ex. SDG&E-13 (Woldemariam) at 148:7-12.

[136] Ex. SDG&E-13 (Woldemariam) at 46:20-25.

[137] Requested in Ex. SDG&E-25 and SDG&E-25-CWP-R, workpaper 920R.

[138] UCAN (Woychik), pp. 304:1 and 304:13-14.

[139] Ex. SDG&E-13-2R (Woldemariam) at 168:21-22.

with customers and contract vendors. The current application landscape is not meeting Vegetation Management's overall work management needs in a single system. This project will utilize various SAP products to meet vegetation management's overall work management needs in a more holistic single system solution. SAP Analytics Cloud will also be incorporated allowing the Vegetation Management department to explore data by forecasting work, tracking progress, and analyzing resource capacity. The new system will allow vegetation management to review planned inspections, prepare for additional planned work, and track corrective work.

SDG&E must rely on accurate and reliable financial reporting of vegetation management activities to regulatory agencies. Vegetation Management requires the ability to improve the existing reporting architecture and reporting reliability to accurately and consistently identify and report specific and separated costs associated with multiple Vegetation Management activities. These requirements are driven by regulatory mandate and in support of ongoing data requests. Enhancements and automated system capabilities will ensure consistent and accurate reporting of expenses, eliminating manual data gathering and reconciliation.

Software upgrade and integration will also ensure that the critical work management system (CityWorks) used for vegetation management is information security compliant by upgrading to a supported version of Oracle, Esri GIS, and will enhance Epoch Field. This will update system integrations with SAP CCMS, Middle Tier interface to Epoch MDTs (Mobile Data Terminal) and the reporting database. This upgrade positions the Vegetation Management program to use advanced data analytics to improve field operations, align with a strategic roadmap, consolidate systems, remove redundancies, and improve visualization of work via integrated geospatial solutions.

To summarize, SDG&E has provided justification for the need to fund this IT Capital request based on IT technical needs for Vegetation Managements maturing and evolving business requirements, and to support the program's maturity model and regulatory reporting.

VII. CONCLUSION

Through my direct testimony and this rebuttal, SDG&E has established the following:

- SDG&E's risk assessment tools, including the WiNGS-Planning model, serve to inform investment in grid hardening through covered conductor and strategic undergrounding using evolving data to promote efficiency and target the areas of highest risk;

- SDG&E has established risk reduction targets that balance safety, reliability, and affordability, and are consistent with regulatory and statutory directives to reduce wildfire and PSPS risk;
- Over 96% of SDG&E's undergrounding and covered conductor installation from 2025-2027 will occur in areas in the top 10% of risk;
- A circuit-based approach to hardening and implementation of strategic undergrounding on high-risk circuits in the HFTD presents the optimal (and often only) way to reduce both wildfire risk and the use of PSPS as a long-term wildfire mitigation strategy.
- Two-way balancing for wildfire mitigation plan programs affords SDG&E the flexibility to respond to innovations in risk assessment, changing regulatory directives, and new technologies, while affording both transparency and accountability;
- Cost caps and the use of 2021 dollars to calculate future forecasts are unreasonable.

For the reasons stated herein, SDG&E's wildfire mitigation forecasts and proposals are just, reasonable, and necessary, and the Commission should approve them without modification.

This concludes my prepared rebuttal testimony.

APPENDIX A

GLOSSARY OF TERMS

ACRONYM	DEFINITION
AB	Assembly Bill
Cal Advocates	The Public Advocates Office of the California Public Utilities Commission
CARB	California Air Resources Board
CPUC	California Public Utilities Commission
FSD	Field Service Delivery
FTE	Full Time Equivalent
GIS	Geographic Information Systems
HFTD	High Fire Threat District
IBEW	International Brotherhood of Electrical Workers
ICS	Incident Command System
IOU	Investor-Owned Utility
IT	Information Technology
MAVF	Multi-Attribute Value Function
MDT	Mobile Data Terminal
MGRA	Mussey Grade Road Alliance
O&M	Operations and Maintenance
OEIS	Office of Energy Infrastructure Safety
PCF	Protect Our Communities Foundation
PSPS	Public Safety Power Shutoff
RAMP	Risk Assessment and Mitigation Phase
RSE	Risk Spend Efficiency
SB	Senate Bill
SBUA	Small Business Utility Advocates
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPS	Solar-Plus-Storage
TTBA	Tree Trimming Balancing Account
TURN	The Utility Reform Network
TY	Test Year
UAS	Unmanned Aerial Systems
VETS	Vegetation Electronic Ticketing System
VMBA	Vegetation Management Balancing Account
WFRR	Wildfire Risk Reduction
WiNGS	Wildfire Next Generation System
WMBA	Wildfire Mitigation Plan
WMP	Wildfire Mitigation Plan Balancing Account

APPENDIX B

DATA REQUEST RESPONSES

[*attach responses to discovery requests to testimony so that they are become part of the record when your testimony is admitted*]

Appendix B - SDG&E Response to TURN-SEU-017 Questions 6.h.i. and 8

Question 6-Continued

h. Please provide a description of how PSPS risk reduction is calculated (starting in cell A27).
    i. Please provide the numerical values used to quantify PSPS risk and explain how these inform the PSPS risk reduction value.

SDG&E Response 6h(i):

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_6h_i_2023_01_23.xlsx

Data Request Number: TURN-SEU-017

Proceeding Name: A2205015_016 - SoCalGas and SDGE 2024 GRC

Publish To: The Utility Reform Network

Date Received: 1/12/2023

Date Responded: 1/27/2023

8. Re Excel workpaper "1Final TY2024 GRC RSE Workpaper - SDGE - Wildfire_53773", tab "Risk Scoring Workpaper," please explain and provide underlying data (in Excel) and sources for how the following metrics were determined, (starting in row 58 and below).

    a. Expected total fire size (please include at minimum if this is in acres?) (row 59)

SDG&E Response 8a:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Data Request Number: TURN-SEU-017

Proceeding Name: A2205015_016 - SoCalGas and SDGE 2024 GRC

Publish To: The Utility Reform Network

Date Received: 1/12/2023

Date Responded: 1/27/2023

Question 8-Continued

b. Total Significant Fire Incidents per Year (row 60)

SDG&E Response 8b:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Data Request Number: TURN-SEU-017

Proceeding Name: A2205015_016 - SoCalGas and SDGE 2024 GRC

Publish To: The Utility Reform Network

Date Received: 1/12/2023

Date Responded: 1/27/2023

Question 8-Continued

c. % Tier 2 (row 62)

SDG&E Response 8c:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

d. % Tier 3 (row 63)

SDG&E Response 8:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Data Request Number: TURN-SEU-017

Proceeding Name: A2205015_016 - SoCalGas and SDGE 2024 GRC

Publish To: The Utility Reform Network

Date Received: 1/12/2023

Date Responded: 1/27/2023

Question 8-Continued

e. Total Serious Injuries and Fatalities (SIFs) per significant fire incident (row 61)

SDG&E Response 8e:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

f. Total safety index per year (including what the .00005 represents and where it comes from) (row 68)

SDG&E Response 8f:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

g. $ per acre (row 69)

SDG&E Response 8g:

Please refer to the following attachments with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx
- TURN_SEU_017_Question_8_Suppression_Cost_2023_01_23.xlsx

Question 8-Continued

h. $ per structure damaged (row 70)

SDG&E Response 8h:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

i. Structures per acre (row 71)

SDG&E Response 8i:

Please refer to the following attachments with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx
- TURN_SEU_017_Question_8_RedbookDatasetPreProcessing_2023_01_23.xlsx

Question 8-Continued

j. PSPS LORE – Total incidents per year (row 76)

SDG&E Response 8j:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

k. PSPS – Total Safety Incidents per year (row 87)

SDG&E Response 8k:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

l. Financial – PSPS – Tier 3 $M USD per incident […] (including a definition of this) (row 97)

SDG&E Response 8l:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

m. Financial – PSPS – Tier 2 $M USD per incident […] (including a definition of this) (row 98)

SDG&E Response 8m:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

Question 8-Continued

n. All rows/values of the reliability calculation (rows 99-107).

SDG&E Response 8n:

Please refer to the following attachment with supporting documentation, formulas, and an explanation of how those values are calculated:

- TURN_SEU_017_Question_8_Risk_Scoring_Workpaper_Table_2023_01_23.xlsx

SDGE

PSPS reduction calculations for Strategic Undergrounding

Legend	color
Input	
Output (calculation)	
calculation	

This color legend only applies to this workbook

Step 1: Estimate number of customers affected by this mitigation (per year)
Table in K41:N47

	2022	2023	2024
Tier 3	1409	1567.53336	1881.262535
Tier 2	1124	1250.46664	1500.737465
Total	2533	2818	3382

Tier 2 (%)	56%
Tier 3 (%)	44%

Comments

To estimate the number of customers affected by this mitigation per year, SDG&E uses actual data for projects scoped in 2022 per Tier and extrapolates proportionally based on the 2022 ratio.

Step 2: Estimating percentage of customers per type in 2020. Note that table label indicated 2022 customer counts
Table in K51:S53

	2020 Residential/Industrial/Commercial	2020 Essential	2020 Urgent	2020 Medical Baseline	Total
Tier 3	1190	106	0	0	1296
Tier 2	5827	68	0	1	5896
Total	7017	174	0	1	7192

Comments

This step is needed as scaling factors are applied to artificially increase the PSPS impact on SDG&E's customers in the Safety, Reliability, and Financial attributes.
Please refer to the response provided in question 4-c-iii and supporting documentation "Medical_Factors_Table_2023_01_20.xlsx" for additional details on how this scaling factors are estimated and applied in the calculations.

Ratios

	2020 Residential/Industrial/Commercial	2020 Essential	2020 Urgent	2020 Medical Baseline	Total
Tier 3	91.82%	8.18%	0.00%	0.00%	1
Tier 2	98.83%	1.15%	0.00%	0.02%	1

Step 3: Calculate the number of customers per customer type and year
Table A:27 to M33

		Residential/Industrial/Commercial	Essential	Urgent	Medical Baseline	Total
2022	Tier 3	1293.76	115.24	0.00	0.00	1409
	Tier 2	1110.85	12.96	0.00	0.19	1124
2023	Tier 3	1439.32	128.21	0.00	0.00	1567.53336
	Tier 2	1235.83	14.42	0.00	0.21	1250.46664
2024	Tier 3	1727.39	153.87	0.00	0.00	1881.262535
	Tier 2	1483.17	17.31	0.00	0.25	1500.737465

Step 4) Use pre-calculated CoRE values for each customer type to estimate Pre PSPS CoRE
Table O:27 to O:31

	CoRE	Safety	Reliability	Financial
MedicalFactors	0.089260628	0.00288	0.077880628	0.0085
Residential	0.086956628	0.000576	0.077880628	0.0085
Essential	2.432938832	0.01152	2.336418832	0.085

Comments

Please refer to the response provided in question 4-c-iii and supporting documentation "Medical_Factors_Table_2023_01_20.xlsx" for additional details on how this scaling factors are estimated and applied in the calculations.

		Residential/Industrial/Commercial	Essential	Urgent	Medical Baseline	Total
2022	Tier 3	1293.76	115.24	0.00	0.00	1409
	Tier 2	1110.85	12.96	0.00	0.19	1124

		Pre PSPS CoRE
2022	Tier 3	392.88
	Tier 2	128.15

Comments

Pre CoRE values for Tier 3 and Tier 3 are calculated based on 2022 customer counts

Step 5) Calculate Pre PSPS risk scores as LoRExCoRE and risk reductions based on SME assumption on mitigation effectiveness
Table N:27 to Q:32

		Pre PSPS CoRE	Pre PSPS LoRE	Pre PSPS Risk	Extent of PSPS mitigation/Effectiveness	PSPS Risk Reduced
2022	Tier 3	392.88	3.20	1257.21	100%	1257.21
	Tier 2	128.15	2.40	307.56	100%	307.56

Comments

To calculate the overall risk reduction of this mitigation, a 100% mitigation effectiveness is estimated by Subject Matter Experts. This assumption is currently being review and will be updated in the near future.

SDGE

Row Number	Name	Incident Type	Metric	Assumed Value	Source	Explanation
59			Expected total fire size	500,000	SME Input, based on Wildfire Activity Statistics	Subject Matter Expert assumption to estimate the potential maximum footprint (acres) of a catastrophic wildfire in SDG&E service territory. The assumption is 500,000 acres.
60			Total Significant Fire Incidents per Year	0.05	SME, internal data	Subject Matter Expert conservative assumption to estimate the frequency of a catastrophic wildfire in SDG&E service territory. The assumption is 1 in 20 years
61			Total Serious Injuries and Fatalities (SIFs) per significant fire incident	12.6	SME, internal data	See Tab "Supporting Data" starting on row 6
62			% Tier 2	35.79%	calculated from Technosylva simulations, ratios based on cAcrAve	See Tab "Supporting Data" starting on row 18
63			% Tier 3	62.65%	calculated from Technosylva simulations, ratios based on cAcrAve	See Tab "Supporting Data" starting on row 18
64			% Non-HFTD	1.56%	calculated from Technosylva simulations, ratios based on cAcrAve	See Tab "Supporting Data" starting on row 18
68			Total safety index per year	1.88	Calculation	See Tab "Supporting Data" starting on row 33
69			$ per acre	$1,766	SME assumption	Subject Matter Expert conservative assumption to estimate the financial amount of suppression and restoration activities. See "TURN_SEU_017_Question_8_Suppression_Cost_2023_01_23.xlsx" for details on how this value is calculated
70			$ per structure damaged	$1,000,000	SME assumption	See Tab "Supporting Data" starting on row 48
71			Structures per acre	0.00875	SME assumption	Average value of structures destroyed per acre burned. See "TURN_SEU_017_Question_8_RedbookDatasetPreProcessing_2023_01_23.xlsx" for details on how this ratio is calculated
73	Wildfire LoRE	Tier 3	Total Incidents per Year	6.2	See Masters Inputs -- 2017 –2021 ignition data, SME inputs	Not asked in Data Request, left here for reference only as this value is used to calculate others
74		Tier 2	Total Incidents per Year	5.8	See Masters Inputs -- 2017 –2021 ignition data, SME inputs	Not asked in Data Request, left here for reference only as this value is used to calculate others
75		Non-HFTD	Total incidents per year	7.2	See Masters Inputs -- 2017 –2021 ignition data, SME inputs	Not asked in Data Request, left here for reference only as this value is used to calculate others
76	PSPS LoRE	Tier 3 and Tier 2	Total incidents per year	4	Internal reliability data	Subject Matter Expert conservative assumption to estimate the annual expected number of PSPS de-energization events in SDG&E service territory.
87	Safety	PSPS	Total safety incidents per year	0.018	SME, internal data	See Tab "Supporting Data" starting on row 71
97	Financial	PSPS	Tier 3, $M USD per incident (repair cost, destruction of property)	12.92	SME, internal data	See Tab "Supporting Data" starting on row 87 The name of this variable is incorrect. The correct name for this variable is: Tier 3, $M USD per PSPS de-energization event
98			Tier 2, $M USD per incident (repair cost, destruction of property)	5.54	SME, internal data	See Tab "Supporting Data" starting on row 87 The name of this variable is incorrect. The correct name for this variable is: Tier 2, $M USD per PSPS de-energization event
99	Reliability	HFTD	Reliability index per incident, tier 3	0.0039	SME based on internal reliability data	See Tab "Supporting Data" starting on row 103
100			Reliability index per incident, tier 2	0.0024	SME based on internal reliability data	See Tab "Supporting Data" starting on row 103
101		Non-HFTD	Reliability index per incident	0.0001	SME based on internal reliability data	See Tab "Supporting Data" starting on row 103
102		PSPS	Tier 3, SAIDI Minutes per year	37.62	SME, internal data	See Tab "Supporting Data" starting on row 131
103			Tier 3, SAIFI Outages per year	0.02	SME, internal data	See Tab "Supporting Data" starting on row 131
104			Tier 3, Reliability Index per incident	0.025	Calculation	See Tab "Supporting Data" starting on row 131
105			Tier 2, SAIDI Minutes per year	16.12	SME, internal data	See Tab "Supporting Data" starting on row 131
106			Tier 2, SAIFI Outages per year	0.01	SME, internal data	See Tab "Supporting Data" starting on row 131
107			Tier 2, Reliability Index per incident	0.011	Calculation	See Tab "Supporting Data" starting on row 131

Appendix C - Risk Model Working Group Presentation - December 14, 2022

RISK MODEL WORKING GROUP

Comprehensive Accounting For Wildfire Smoke Consequences

December 14, 2022

CALIFORNIA OFFICE OF ENERGY INFRASTRUCTURE SAFETY

SMEs

Prompt	Question	SME
1. Two obvious smoke consequences are the impact of smoke on air quality (with resultant health impacts); and the impact of wildfire related Carbon-Dioxide (CO_2) emissions on global warming.	a. Are there other wildfire smoke related consequences that should be considered?	Richie Veihl
2. In terms of quantifying the impact of wildfire smoke on air quality and health:	a. What existing models and research are available? What data sources and approaches are available to validate and refine the model based on actual data? (**give examples? Sensors, hospital data, etc.)	@Hamon, Kristin L (AQI? RMS Model into WiNGS Ops/Planning?)
	b. What should the inputs to and outputs from this model be for the purpose of risk and risk spend efficiency modeling?	@Sebastian Peral, Joaquin, @Butler, Daniel J, @Wang, Denis
	c. How should this model be incorporated into existing wildfire models?	@Sebastian Peral, Joaquin @Flamenbaum, Robert
3. In terms of quantifying the impact of wildfires on CO_2 emissions, and the subsequent impact on global warming:	a. What existing models and research are available? What data sources and approaches are available to validate and refine the model based on actual data?	@Beller, Maxwell M @Kull, Mackenna N
	b. What should the inputs to and outputs from this model be for the purpose of risk and risk spend efficiency modeling?	
	c. How should this model be incorporated into existing wildfire models?	

QUESTION 1

Two obvious smoke consequences are the impact of smoke on air quality (with resultant health impacts); and the impact of wildfire related Carbon-Dioxide (CO_2) emissions on global warming. Are there other wildfire smoke related consequences that should be considered?

SDG&E

Q: Two obvious smoke consequences are the impact of smoke on air quality (with resultant health impacts); and the impact of wildfire related Carbon-Dioxide (CO_2) emissions on global warming. Are there other wildfire smoke related consequences that should be considered?

- It is SDG&E's position that there are several federal and statewide agencies, as well as the academic community, that are better equipped to quantify the holistic impact of wildfire smoke on air quality, health, and CO_2 emissions. There are several dimensions of wildfire impacts on air quality – which are often convoluted and contradictory and require information that is not in the purview or the control of SDG&E – and it is difficult to define relative weights between them. For example, it may be difficult to quantify the actual impacts on wildfire smoke on air quality, given that many sources, including other greenhouse (GHG) emissions sources, contribute to air quality. Additionally, there is not a consensus regarding the impacts of wildfire smoke on overall air quality and any specific resultant health impacts, to the extent they exist. In addition, there are challenges in ascertaining whether and to what degree the smoke inhalation is the triggering cause for a given health impact, because health conditions may be influenced by several factors, including lifestyle choices and pre-existing conditions, and the health impact may not manifest for years or even decades after the wildfire event.

- SDG&E will continue to review scientific, academic and governmental research regarding the impacts of wildfire smoke. But at this time, SDG&E does not believe that any other wildfire smoke-related consequences should be considered for risk modelling purposes.

QUESTION 2

In terms of quantifying the impact of wildfire smoke on air quality and health:

a.What existing models and research are available? What data sources and approaches are available to validate and refine the model based on actual data? (**give examples? Sensors, hospital data, etc.)
b. What should the inputs to and outputs from this model be for the purpose of risk and risk spend efficiency modeling?
c. How should this model be incorporated into existing wildfire models?

SDG&E

In terms of quantifying the impact of wildfire smoke on air quality and health:

a. What existing models and research are available? What data sources and approaches are available to validate and refine the model based on actual data? (**give examples? Sensors, hospital data, etc.)

b. What should the inputs to and outputs from this model be for the purpose of risk and risk spend efficiency modeling?

c. How should this model be incorporated into existing wildfire models?

a. CARB's Smoke Management Programs: The 2022 CARB scoping plan released in late November 2022 proposes addressing the emissions released during a fire and the resulting impacts at statewide level. Wildfire smoke impacts and potential mitigations are also debated in academia as well as the government agencies charged with protecting the health and wellbeing of the public (e.g. CARB, EPA).

b. SDG&E’s risk spend efficiency modeling for investment aims to design and improve its infrastructure to prevent utility ignited fires and reduce their potential size and impact to its customers. SDG&E’s view is that by prioritizing the reduction and mitigation of utility-related ignitions in its risk models, it reduces any corresponding smoke impacts, thus secondary smoke impacts should not currently be included in its risk models. SDG&E will continue to review academic and governmental research regarding the impact levels of wildfire smoke and, if requested, will support the agencies designated to address AQI issues.

c. Today, SDG&E’s Risk Quantification Framework includes “Acres Burned” in its MAVF Safety attribute. This is partially intended to account for the detrimental impacts from pollution to human health. SDG&E continues to monitor ongoing research and the 2022 CARB final scoping plan released on November 16, 2022.

QUESTION 3

In terms of quantifying the impact of wildfires on CO2 emissions, and the subsequent impact on global warming:

a) What existing models and research are available? What data sources and approaches are available to validate and refine the model based on actual data?
b) What should the *inputs to* and *outputs from* this model be for the purpose of risk and risk spend efficiency modeling?
c) How should this model be incorporated into existing wildfire models?

SDGE

In terms of quantifying the impact of wildfires on CO_2 emissions, and the subsequent impact on global warming:

a) What existing models and research are available? What data sources and approaches are available to validate and refine the model based on actual data?
b) What should the inputs to and outputs from this model be for the purpose of risk and risk spend efficiency modeling?
c) How should this model be incorporated into existing wildfire models?

a) Based on SDG&E's research, the U.S. Forest Service has a model called the First Order Fire Effects Model (FOFEM) which, amongst other things, can estimate the greenhouse gas emissions of a fire based on several inputs. This model was used by the California Air Resources Board (CARB) for analysis on past wildfires in the state and their relative emissions. The inputs of this model are fuel loading, fuel and vegetation maps, and fuel moisture maps. The fuel moisture input can be measured through direct measurements, remote sensing, and modeling to create a scientifically viable dataset.

b) The calculation of CO_2 emission is convoluted; ongoing research should be completed and vetted prior to making determinations about the use of wildfire smoke data in risk and risk spend efficiency modeling. For instance, if SDG&E were to consider the impact of CO_2 due to wildfire then we should also consider any ecological benefits of new growth capturing carbon after a fire, and models should be honed to better identify the impacts of utility-related wildfire smoke. Because of the current inherent uncertainty in the inputs, the outputs of the data, as well as impactful assumptions in social cost of carbon calculations, might reduce the legitimacy and helpfulness of this type of modeling for investment justifications.

c) SDG&E believes that it is prudent at this time to continue to monitor ongoing research performed by the U.S. Forest Service, CARB, and other agencies. When fully developed, Energy Safety and all stakeholders may further vet the appropriateness of its use in existing wildfire risk models.

Appendix D - Joint IOU Covered Conductor Working Group Report

JOINT IOU COVERED CONDUCTOR WORKING GROUP REPORT

2023 Wildfire Mitigation Plan

Table of Contents

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List of Appendices

1 Introduction

In the 2021 WMP Update Final Action Statements, Energy Safety ordered the Joint IOUs[1] to coordinate to develop a consistent approach to evaluating the long-term risk reduction and cost-effectiveness of covered conductor (CC) deployment, including 1) the effectiveness of CC in the field in comparison to alternative initiatives and 2) how CC installation compares to other initiatives in its potential to reduce PSPS risk. The utilities thus formed a Joint IOU Covered Conductor Working Group and developed an approach, assumptions, and preliminary milestones to enable the utilities' to better discern the long-term risk reduction effectiveness of CC to reduce the probability of ignition, assess its effectiveness compared to alternative initiatives, and assess its potential to reduce PSPS risk in comparison to other initiatives. The approach consisted of multiple workstreams including: Benchmarking, Testing, Estimated Effectiveness, Recorded Effectiveness, Alternatives Comparison, Potential to Reduce PSPS Risk, and Costs. In the 2022 WMP Update filings, the utilities produced a joint report that provided an update on their progress for each of the workstreams, added efforts, and preliminary plans for 2023.

In the 2022 WMP Update Final Decisions, Energy Safety identified Areas of Continued Improvement and Required Progress (ACI) for all utilities to expand this working group to include: 1) Joint CC Lessons Learned, 2) CC Maintenance and Inspection (M&I) Practices, and 3) New Technologies Implementation. Given these directions, the utilities expanded the Joint IOU Covered Conductor Working Group to include 10 workstreams and began meeting on the new workstreams in Q3/Q4 2022.

2 Overview

The information compiled and assessments completed in 2022 continue to indicate CC effectiveness between approximately 60 to 90 percent in reducing the drivers of wildfire risk, consistent with benchmarking, testing and utility estimates. In 2022, laboratory testing on CC has largely been completed with a few tests remaining.

In 2023, the utilities plan to conduct workshops across several workstreams to assess testing results, identify CC M&I best practices, develop a common framework for calculating the effectiveness of a combination of alternatives, assess data and information for effectiveness of new technologies and share practices and implementation strategies, and assess studies to be performed on CC's ability to reduce PSPS impacts amongst other actions. The utilities will also continue to meet to further benchmark efforts, improve methods for estimating and measuring effectiveness, and continue to track and compare unit costs. Below, the utilities describe the progress made on each workstream and steps planned to continue this effort in 2023.

As explained in the 2022 WMP Update report, the current type of CC being installed in each of the utilities' service areas is an extruded multi-layer design of protective high-density or cross-linked polyethylene material. In this report, "covered conductor" or "CC" refers generally to a system installed on cross-arms, in a spacer cable configuration, or as aerial bundled cable (ABC). Distinctions are made where utilities install CC on cross arms and in a spacer cable configuration. Table 1 below, provides an

[1] In this progress report, "Joint IOUs," "IOUs," or "utilities" refers to SDG&E, PG&E, SCE, PacifiCorp, BVES, and Liberty.

updated snapshot of the approximate amount and types of CC installed in the utilities' service areas through 2022.

Table 1: Covered Conductor Type and Approximate Circuit Miles Deployed by Utility

Utility	First covered conductor installation (year)	Type of covered conductor installed	Approx. miles of covered conductor deployed through 2022	Notes
SCE	2018	Covered Conductor	4,400	Includes WCCP and Non-WCCP
	2022	Spacer Cable	0.15	Pilot
	Installed Historically	Tree Wire	50	
	Installed Historically	ABC	64	
PG&E	2018	Covered Conductor	960	Primary distribution overhead only
	2022	ABC	3	Like for like replacement
SDG&E	2020	Covered Conductor	84	
		Tree Wire	2	
		Spacer Cable	6	
Liberty	2019	Covered Conductor	11	
	2019	Spacer Cable	9	
Pacificorp	2007	Spacer Cable	76	
	2022	Covered Conductor	7	
Bear Valley	2018	Covered Conductor	34	

3 Testing

3.1 Introduction

In 2022, the joint IOUs performed Phase 2, or testing of CC, to better understand the advantages, operative failure modes, and current state of knowledge regarding CCs. As explained in the utilities' 2022 WMP Update filings, the utilities contracted with Exponent, Inc. (Exponent) to develop a report for a Phase 1 study (see Appendix A). The Phase 1 study consisted of a literature review, discussions with SMEs, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. The Phase 1 report was completed in December 2021 and was an attachment to the utilities' 2022 WMP Update filings. The outcome of the Phase 1 report identified gaps in previous testing and informed the scope of laboratory testing. For the remainder of 2022, the IOUs executed Phase 2 to perform testing and analyses of CC, which had the following objectives:

- Develop test plans based on Phase 1 report identified gaps and recommendations
- Complete physical testing of CC
- Document and discuss results from physical testing of CC

Within Phase 2 of the study, SCE, SDG&E, and PG&E all performed specific testing scopes of work, informed by the findings and recommendations of the Phase 1 report issued by Exponent. The three utilities, led by SCE, contracted with Exponent to independently investigate the effectiveness of CC for overhead distribution systems and, in the case of PG&E and SDG&E, executed additional testing plans as part of this joint effort.[2] Exponent conducted several testing scenarios that covered various contact-from-object, wire down, system strength, flammability, and water ingress scenarios. PG&E developed an additional test plan to ensure coverage of failure modes and additional CC types. SDG&E's additional test plan included environmental, service life, UV exposure, degradation, and mechanical strength tests. Exponent's investigation included lab-based testing of 15 kV rated 1/0 aluminum conductor, steel reinforced (ACSR) CC provided by SDG&E, 17 kV and 35 kV rated 1/0 ACSR provided by SCE, 22 kV rated 397.5 kcmil all aluminum conductor (AAC) provided by PG&E, and 17 kV rated 2/0 copper CC provided by SCE (corrosion testing only). PG&E's additional testing included 15 kV rated 397.5 AAC and 15 kV rated 1/0 ACSR. SDG&E's additional testing included a 15 kV rated 1/0 ACSR conductor.

SCE's testing began in Q1 2022 and was completed in Q4 2022. Exponent completed its final report in late December 2022.[3] SDG&E and PG&E began testing in Q2 2022. PG&E completed its testing and finalized its report in December 2022.[4] SDG&E has not completed all its testing with some tests anticipated to be competed in Q1 and early Q2 2023. All testing is not yet complete; however, the utilities have recently started to collaborate on the results of the tests that have been completed. This report provides a summary of the test results that have been completed. In 2023, the utilities plan to continue discussing the results of the tests as further described below.

Based on all the testing completed as of the end of December 2022, the following high-level conclusions were made:[5]

- CC effectiveness was evaluated by phase-to-phase contact and simulated wire-down testing. The study indicated that CCs are up to 100% effective at preventing arcing and ignition in tested scenarios at rated voltages. This is consistent with documented field experience as reported in the Phase I report.
- The study indicated CCs showed effectiveness at preventing arcing and ignition and limited current flow to less than 2.5 mA in 100% of tested phase-to-phase contact scenarios at rated conductor voltages, which included different types of vegetation, balloons, simulated animals, and conductor slapping.
- CCs exceeded insulation ratings for rated voltage with 50% covering removed.
- In wire down situations, broken CCs and CCs with damage that exposed the underlying metal showed potential for arcing/ignition. However, pursuant to the CCs tested, the results showed the CCs prevented arcing and ignition during simulated wire-down events in dry brush in the Exponent testing.
- Thermal testing was performed to understand the impact of a nearby wildfire on CC installations. Results suggested that the heat fluxes and times required for auto-ignition of the polyethylene sheaths were unlikely to be encountered during a surface or low-lying brush fire; however, a canopy fire may be sufficient to cause conductor sheath ignition.

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[2]To distinguish between the results described below, "SCE testing" refers to the joint IOU Exponent testing, "PG&E testing" refers to the testing PG&E conducted, and "SDG&E testing" refers to the testing SDG&E has completed and is still conducting for the Joint IOU effort.
3 The joint IOU Exponent report entitled, "Joint-IOU Covered Conductor Testing Cumulative Report 12-22-22" is included in each utility's Supporting Documents.
4 The PG&E report entitled, "PGE Covered Conductor Testing-1219" is included in each utility's Supporting Documents.
5All tests were performed under controlled conditions. Actual field performance may vary depending on a variety of factors.

- Water ingress testing was performed to understand if implementation of CCs inherently seals the conductor from moisture exposure, recognizing moisture is often a factor in corrosion occurrences. Stripped ends of CCs and CCs with insulation-piercing connectors (IPCs) were found to be susceptible to water ingress. While the test conditions were extreme relative to typical service conditions, water may travel down the conductor length from a stripped end.
- Corrosion was observed under the CC sheath near the stripped ends but was not observed under IPCs following salt spray testing. While this indicates that subsurface corrosion is possible near a stripped CC end, subsequent tensile testing showed minimal reduction in total strength of the conductor after corrosive environmental exposure for 1,000 hours. Potential water-ingress mitigation measures may help to prevent corrosion in areas where precipitation is likely to collect on the conductor.
- Mechanical testing was performed to assess the strength of CCs and their associated hardware. Strength testing of splices met or exceeded the rated strengths of the conductors. In simulated tree-fall conditions and insulator slip tests, one insulator type exhibited deformation of the metal pin but at a slip strength beyond GO 95 requirements. Another type of insulator exhibited conductor slippage with no apparent signs of damage but at a slip strength below GO 95 requirements.

3.2 Summary of Testing Results

3.2.1 Arc Testing

The purpose of the Arc testing was to understand the effectiveness of CC in mitigating faults and ignition for various contact-from-object scenarios. These tests involved simulating wire-to-wire contact and contact from foreign objects by bridging two conductors, one energized and one grounded. Several permutations of CC, sheath damage, and bare conductors were tested. Overall, CC was successful at mitigating arcing/ignition under all tested conditions at their design voltages. Current flows for CC were recorded to be less than 2.5 mA. In comparison, current flows for bare wire were recorded to be greater than 2,000 mA. For a five-minute contact duration, no arcing, insulation breakdown, or visual damage was observed.

The testing of phase-to-phase contact demonstrates that CC is effective at reducing arcing and the potential for ignitions whenever the insulation is intact, and the operating voltage is within normal ranges. Potential for ignition exists when the insulation is damaged/removed which may occur when objects collide with the CC. This testing also involved energizing the CC at extreme voltages much higher than the CC was designed to withstand. At 90 kV, which far exceeds the conductor ratings, there was no insulation breakdown, pinhole formation, or arcing/ignition observed.

These test results illustrate the effectiveness of CC at mitigating ignitions due to contact-from-object events. Future testing may be done to simulate branches or other debris striking the conductor at speed to determine the ability of the insulation to withstand impact. Future testing may also include simulating the effects of long-term object contact.

3.2.2 Simulated Wire-down Testing

The wire-down testing investigated ignition risk posed by CC and bare wire wire-down events. Flaws were introduced to the covering to represent various scenarios during a CC wire-down. These flaws included the full removal of the covering, removing half the thickness of the covering, and having a broken end. The SCE wire-down testing demonstrated that conductors whose covering was still intact upon contacting the dry brush did not result in an ignition. Upon introducing a full thickness flaw into the covering, which exposed the bare conductor, arcing and ignition were observed. PG&E testing showed that Individual conductor strands can be exposed from the covering during simulated conductor breaks.

SCE testing was also performed by inserting a half-thickness flaw into the covering which did not result in arcing or ignition; this indicates that the CC can sustain significant damage without exposing the bare conductor and still be effective at mitigating ignitions. This conclusion is also corroborated through testing that showed that the CCs had a minimum of 66% of the insulation rating even with 50% abraded insulation.

3.2.3 Fire risk / Flammability Testing

SCE's Fire Risk testing subjected a small segment of conductor to local radiant heat to simulate how CCs would react to various magnitudes of wildfires. The magnitude of the heat represents surface fires, brush fires, and crown fires. Crown fires with a long residence time have the highest potential to cause damage to the covering of the conductor. The study noted that the measurements were taken with direct contact of the flame; however, properly maintained vegetation clearances would decrease an overhead primary distribution line's potential of being in contact with a flame. According to the inverse square law for heat, the intensity of the flame is inversely proportional to the distance squared X=1/d^2. Using this equation, we can approximate the amount of radiated heat the conductor might experience at a particular distance away from a flame. The shortest distance that should be expected between vegetation and the conductor would be when there are crowns of trees nearby (6-foot clearance, GO 95). There would be a significantly greater distance between the conductor and vegetation for surface and brush fires. At 6 feet, the heat flux is approximately 30% of what would be felt directly at the flame. At a distance of 6 feet (1.8288m) and utilizing the scenario-based heat fluxes provided, we can approximate the amount of heat the conductor would encounter. See Table 2 below that shows the heat flux ranges for direct contact and contact at six feet for the different fire types.

Table 2: Heat Flux Ranges by Fire Type

Fire Type	Heat Flux (kW/m^2) Range with Direct Contact		Heat Flux (kW/m^2) Range with Contact at 6 feet (1.8288m)	
Surface fires	18	77	5	23
Brush fires	97	110	29	33
Crown fires	179	263	54	79

3.2.4 Corrosion Testing

To make electrical and structural connections, some utilities remove the covering of the conductor to expose bare wire. When a bare wire is exposed to the elements, it becomes more susceptible to various types of corrosion. This was a common failure mode that was identified when benchmarking with other utilities. To mitigate this failure mode, some utilities use medium voltage fusion tape (MVFT) on electrical connections to the line. SDG&E utilizes Insulated Piercing Connectors (IPCs) to make electrical connections and a tensioning clamp for structural connections. Water ingress testing was performed by both SCE and PG&E to evaluate the corrosion susceptibility for instances when the covering is removed. SCE varied the test by utilizing a tool specifically designed to remove the covering to expose a length of bare conductor and removing the covering manually without unique tools; they also varied the conductor material to include copper and aluminum. The conductor was then placed vertically with a dedicated reservoir of fluorescent water at the top to simulate moisture intrusion. In all the tests, water was visible at the opposite end of the conductor segment within 5-10 minutes. PG&E's version of the testing was varied to test various types of CC with and without water-blocking agents. PG&E's test was also slightly different because a length of exposed conductor was not left at the top, but rather a clean cut was made on each of the conductors. For the conductors without water-blocking agents, fluorescent water was observed at the opposite ends of the conductor while there was no liquid observed for the conductors with water-blocking.

Although the water ingress testing setup, conducted in a submersible configuration, is not likely to occur in the field, water ingress can lead to accelerated corrosion. Additional preventative actions taken during installation and/or maintenance, such as the use of IPCs, tension clamps, gel wraps/packs, wildlife covers, or MVFT, may help limit moisture ingress and related corrosion effects. For example, PG&E's water immersion test of gel wraps demonstrates this mitigation's ability to prevent water intrusion for splice and other electrical connections. Additionally, corrosion can potentially be mitigated with the use of copper CCs due to copper being less susceptible to corrosion than aluminum in high corrosive areas.

Salt spray testing was performed by SCE to evaluate the susceptibility of exposed ends of CC to corrosion in coastal and industrial environments. This testing utilized a 5% salt solution for 168 hours with a SO_2 solution introduced intermittently. The testing varied like the water intrusion testing, but also added artificial defects to simulate mid-span damage and performed the testing on bare conductors as well. Corrosion was identified on the exposed portion of the CC as well as under the covering. When a conductor had simulated damage, the most severe corrosion occurred. Exponent did identify that a segment of CC was evaluated which utilized an IPC; however, this did not demonstrate corrosion.

PG&E's atmospheric corrosion tests consisted of 1,000 hours of exposure using a 5% salt solution. This test evaluated bare conductor, CC, and splice connections with MVFT or gel packs. PG&E summarized that aluminum CCs are more susceptible to corrosion compared to bare conductor when exposed to a corrosive environment. This ingress is reduced with the application of MVFT and altogether eliminated with the use of gel packs. It is also important to note that all conductors met the rated breaking strength after the testing was completed.

3.2.5 Aging Susceptibility Testing

PG&E performed UV weathering tests with 1,000 hours of exposure time (ASTM G155-21). Two types of CCs were tested and neither met the tensile or elongation requirements of ANSI/ICEA S-121-733 to be considered resistant to sunlight. The results indicate that the covering is susceptible to degradation and cracking after long-term exposure to UV for the conductors tested.

Exponent, with SDG&E, performed accelerated aging testing by monitoring a segment of the cover at 10% thickness. It is assumed that the rate of change that is observed with a segment at 10% thickness can be used to anticipate the amount of deterioration over 40 years. Three tests were performed at 80C, 110C, and 130C; one test was performed at 80C with 1.60W/m^2 at 340nm UV. The UV data would then be interpolated with the results of the 110C and 130C samples to test the properties of interest; those include dielectric constant, mechanical strength, chemical changes, and visual changes. The results of this test also indicate that the covering is susceptible to degradation and cracking after long-term exposure to UV.

3.2.6 System Strength Testing

After the salt-spray corrosion testing, Exponent evaluated the tensile testing strength of the various aluminum, copper, and steel strand samples. The results from the individual strands can be used to assess the condition of the whole conductor. They showed that even though the aluminum strands underwent corrosion due to the accelerated aging, there was not a significant loss of strength in the conductor overall. For conductors with IPCs installed, there was a measurable decrease in tensile strength of the conductor strands related to the damage caused by the IPC, the degradation was not due to corrosion. Other utilities that utilize IPCs to make electrical connections have not identified this to be a concern.

PG&E evaluated the tensile strength of the conductors to confirm that they met the rated breaking strength and to evaluate how the conductor and cover would react. Both conductors tested exceeded the rated breaking strength. At the point of fracture, necking occurred but was more significant for the covering than the aluminum and steel wires. Small segments of exposed conductor could be seen protruding from the covering. Because of this, breaks in the conductor could result in phase-to-ground contact, which could lead to an ignition.

SCE’s system strength tests included a splice maximum load test, insulator slip test, and a tree fall test. For the splice max load test, all spices met or exceeded specifications. For the insulator slip test and tree fall test, two different types of insulators were used. One experienced deformation of the metal pin while the other showed signs of slippage with no apparent damage. For a simulated tree fall on a dead-end configuration, a failure occurred with smaller sized conductor due to it slipping out of the dead-end shoe. It was noted that the failure likely occurred above the rated strength of the conductor. For larger conductors, the failure point was at the crossarm.

3.2.7 Electrical Properties Testing

PG&E performed leakage current and dielectric withstand tests on the covering and various splice coverings. For the covering tests, two different types and sizes of conductor were used, both with full cover thickness and 50% cover thickness to simulate a flaw. In all the covering test cases, the insulation failed at a voltage level that greatly exceeded its rated value. The splice covers tests consisted of a compression splice with gel pack, compression splice with MVFT, and a fired wedge connector with a cover. In all cases the splice coverings met or exceeded the ratings of the CC insulation rating.

To understand if CC could be susceptible to tracking damage, inclined plane tracking and erosion tests and tracking resistance with salt fog tests were performed. For the inclined plane and erosion tests, both conductor samples passed; however, one of the conductors showed a greater erosion depth. The tracking resistance with salt fog tests were designed to understand the impacts of long-term vegetation contact. Again, for these tests, both conductors met the passing criteria but, again, the same conductor showed a greater erosion depth.

PG&E tested the damaging effects that lightning might have on the covering. This was a custom test with guidance from IEEE Std. 4 and IEC 60060-1. The conductor samples were subjected to lightning impulses starting at 85 kV and then increased in the magnitude of the voltage until a breakdown occurred. Both of the conductor samples tested experienced breakdowns between 90-110 kV for each of the 5 samples. The conclusion of the lightning tests is that both coverings have the potential to be damaged by lightning; however, damage is expected to be localized and would be unlikely to cause auto-ignition of the covering.

3.2.8 Covering Properties Testing

The thermal properties of conductor layers were tested by PG&E to verify the glass transition temperatures for each layer of two different conductors. One of the conductors exhibited an onset of glass transition in the conductor shield layer at a lower than emergency temperature rating which could indicate possible early covering degradation if exposed to emergency temperatures repeatedly. The other conductor showed no signs of degradation up to the emergency operating temperatures.

3.3 Next Steps

As explained above, several testing results were completed in December 2022 with a few still remaining. The utilities have met to overview the results of some completed tests but have not yet discussed all results nor in detail yet. In 2023, the utilities will conduct meetings and workshops to assess the testing results, determine if any additional tests are needed, determine if any mitigations are warranted (such as changes to materials, construction methods, or inspection practices), and will meet to assess whether changes to effectiveness estimates are warranted. Additionally, and as part of the workshops, the utilities will discuss the testing results in relation to PSPS de-energization thresholds. Below, we present a preliminary schedule for workshops and discussion themes.

- March 2023 – Corrosion Testing
- April 2023 – Aging Susceptibility Testing
- May 2023 – Arc Testing
- June 2023 – High Impedance Faults
- July 2023 – Tree Fall-in

Once the utilities finalize the workshop schedule, Energy Safety will be invited. Based on findings from the workshops, additional workshops may be scheduled in 2023. Additionally, the utilities will continue to meet on a biweekly basis. Should the results of the workshops lead to changes in materials, construction practices, effectiveness values, etc., the utilities will establish plans to implement these changes and document as part of lessons learned.

4 Recorded Effectiveness

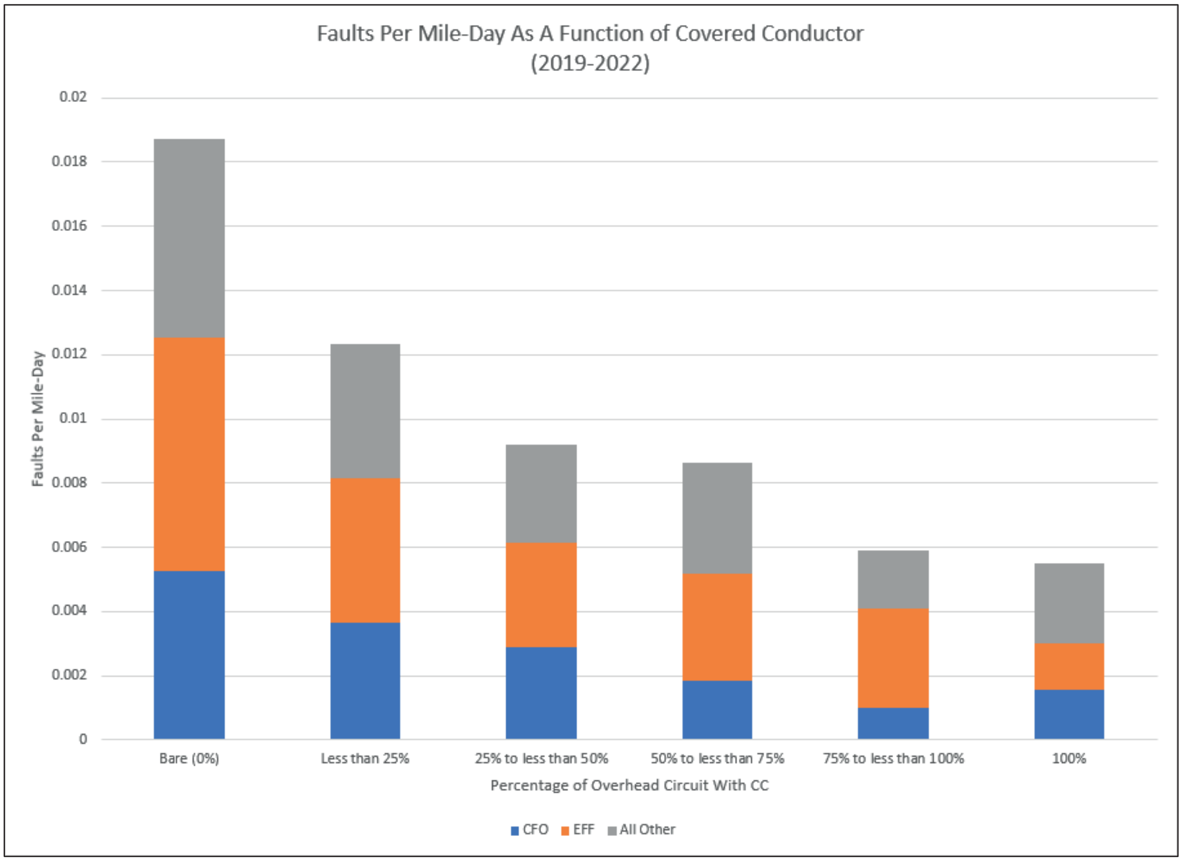
As explained throughout this report, the utilities have continued to implement CC and are using recorded data to help assess its effectiveness in the field. Though the utilities' data is still relatively limited, the outcomes in 2022 in addition to previous years outcomes, as presented below, continue to show CC effectiveness at reducing the risk drivers that can lead to wildfires range between approximately 60 to 90 percent, which is consistent with the utilities' estimated effectiveness values and supported by recent testing results. Below, the utilities provide an update on its 2022 WMP Update report describing data and analyses used to measure recorded effectiveness of CC and plans for 2023 to continue to discuss and share recorded data and methods to measure effectiveness, and document lessons learned.

4.1 Covered Conductor Recorded Effectiveness

4.1.1 SCE

SCE has continued to refine its data and methods to measure the effectiveness of CC in the field. In 2022, SCE set up a CC dashboard that tracks fault rates on overhead distribution circuits with 100% CC installed, circuits that are partially covered, and circuits with no CC installed (bare wire). The data can be broken down by fault sub-drivers such as CFO, EFF, and Other. The data is based on all circuits that traverse HFTD and includes a breakdown of how many miles fall into the fully covered, partially covered, and not covered categories. The dashboard refreshes daily with updated fault and CC data. Because faults that occur on partially covered circuits are difficult to determine if occurred on the covered or bare portion, SCE has further delineated this data into the following partially covered groups: Less than 25%, 25% to 49%, 50% to 74%, 75% to less than 100%. Furthermore, SCE is now using a faults per mile-day method that factors in how long the circuit was fully or partially covered. In 2022, SCE provided overviews of its dashboard, grouping and methods to this working group. Faults per mile-day data from 2019-2022 are shown in Figure 1 below.

Figure 1: SCE Faults Per Mile-Day as a Function of Covered Conductor



By comparing fault events on fully and partially covered circuits to bare circuits in its HFRA on a per mile-day basis from 2019 to 2022, the data shows that circuits fully covered experience approximately 70% less faults than bare conductor when factoring in all sub-drivers (see Table 3 below). Additionally, circuits that are in the 75% to less than 100% covered group experience a similar improvement over bare conductor at approximately 69% less faults. The data also shows a predicted trend with an increasing reduction in faults as more of a circuit is covered. Furthermore, on segments where SCE has covered bare wire, there has not been a CPUC-reportable ignition from the drivers that CC is expected to mitigate.

Table 3: SCE Fault Events on Fully and Partially Covered Circuits Compared to Bare Circuits

Grouping	Reduction Compared to Bare			
	CFO	EFF	All Other	Total
Bare (0%)	0.0%	0.0%	0.0%	0.0%
Less than 25%	30.6%	38.3%	32.0%	34.1%
25% to less than 50%	45.3%	54.9%	50.7%	50.8%
50% to less than 75%	65.0%	54.0%	43.9%	53.8%

Grouping	Reduction Compared to Bare			
	CFO	EFF	All Other	Total
75% to less than 100%	81.0%	57.6%	70.8%	68.5%
100%	70.3%	80.3%	59.2%	70.5%

4.1.2 PG&E

As of the end of 2022, the number of ignitions observed on the CC lines does not provide statistically significant data for calculating effectiveness with respect to ignitions. As most distribution outages (momentary and sustained) typically involve a fault condition, PG&E assumes that all distribution outages can potentially result in an ignition, regardless of other prevailing conditions. Therefore, PG&E is measuring the recorded effectiveness of CC by comparing the outages on the circuit segments with CCs to outages on circuit segments with bare conductors.

PG&E's recorded effectiveness is calculated in three different snapshots. The first snapshot considers all CC installations by the end of 2019 and average yearly outages in 2020-2022. The 2nd snapshot considers the CC installations by the end of 2020 and average yearly outages in 2021-2022. Lastly, all CC installations by the end of 2021 and outages in 2022 are considered in the 3rd snapshot.

PG&E has not included CC installations that were completed in the middle of year 2022. PG&E is only including locations that were completed by end of year (EOY) 2021, so that there is a minimum of 1 year of outage performance data to be able to compare with outage performance in areas with bare conductor.

The comparison was conducted on an outages per year, per mile basis to normalize outage rates pre- and post- CC. Table 4 below presents the results of this preliminary recorded effectiveness analysis.

Table 4: PG&E Recorded Effectiveness Snapshots

Snapshot	Category of OH HFTD circuit segments (downstream of SSDs)	Total CC miles in this category	Total OH HFTD miles in this category	% CC'ed	Average yearly HFTD outages	Outage / Total OH HFTD miles / year	Improvement compared to Category 1
1: CC miles % of total OH miles by the end of 2019	Outages considered: 2020-2022						
	Category 1: not covered at all	0	24,849	0%	9339.7	0.38	-
	Category 2: 1-80% (partial)	27	242	11%	53.7	0.22	**41%**
	Category 3: 80%+ (mostly)	36	38	95%	4.3	0.11	**69%**
2: CC miles % of total OH miles by the end of 2020	Outages considered: 2021-2022						
	Category 1: not covered at all	0	24,950	0%	9544	0.38	-
	Category 2: 1-80% (partial)	122	640	19%	157.5	0.25	**36%**
	Category 3: 80%+ (mostly)	178	185	96%	19.5	0.11	**72%**
3: CC miles % of total OH miles by the end of 2021	Outages considered: 2022						
	Category 1: not covered at all	0	24,942	0%	5978	0.24	-
	Category 2: 1-80% (partial)	148	877	17%	151	0.17	**28%**
	Category 3: 80%+ (mostly)	238	248	96%	18	0.07	**70%**

The calculated outage reduction percentage (used as a measure for the recorded effectiveness) shows that CC sections experience approximately 28-70% fewer faults compared to bare conductor circuit segments.

PG&E’s results are presented in Table 4. These results are preliminary due to the following factors:

- Using an averaged per mile rate for the outages inherently omits the granular perspective related to each individual section of the circuits in PG&E’s service area because it does not capture the impact of localized environmental/weather conditions. Hence, this analysis may over or under-represent effectiveness.
- It is assumed that all distribution outages could potentially result in an ignition. It does not factor in if one type of outage is more or less likely to result in an ignition. However, there are several failure modes such as tie-wire failure that have a much lower likelihood of ignition compared to an outage due to a broken conductor.
- The outages in partially covered and mostly covered categories (category 2 and 3) could have occurred on parts of the line that are not covered, which cannot be validated due to lack of exact geospatial information for the outages.

As part of PG&E’s ignition investigation process, it is incorporating additional review of ignition identification that occurs on a CC line to ensure visibility of failures based on observed incidents. Below are some examples related to the effectiveness of CCs in the field that have been observed in PG&E’s service area.

Example 1: On 5/10/2021, a 125-foot ponderosa pine that was 55-feet away from a pole, failed approximately 40-feet above ground, severing the CC, causing a wire down, and a subsequent CPUC reportable ignition.

Figure 2: PG&E Covered Conductor Effectiveness – Example 1

Example 2: On 5/2/2022, a 120-foot ponderosa pine that was being abated for previously reported structural concerns, fell on a CC line, severing it, and starting a CPUC reportable ignition.

Figure 3: PG&E Covered Conductor Effectiveness – Example 2

These two incidents highlight some limitations concerning CC. In both incidents, there were vegetation management inspections and CC deployed. But even with the combined mitigations, it still resulted in an ignition.

Example 3: On 12/27/2021, two CCs were supporting an entire tree. There was no ignition; however, an electrical outage did occur on the line.

Figure 4: PG&E Covered Conductor Effectiveness – Example 3

4.1.3 SDG&E

As CCs become a larger part of the system, the performance indicators that impact the efficacy of this mitigation will continue to be monitored and measured, including the measured effectiveness. As there are approximately 84 miles of CC installed with an average age of less than one year, SDG&E does not have sufficient data yet to draw any conclusions on the recorded effectiveness of CC.

Moving forward, SDG&E will continue to track the mileage, years of service, and faults on all CC circuit segments and will continue to collaborate with this working group to improve methods to measure the effectiveness of its system hardening initiatives. SDG&E's approach is to calculate the risk events per one hundred miles per year on segments that have been covered and compare the risk event rate before and after the installation of CC.

4.1.4 PacifiCorp

PacifiCorp continues to track risk events within each zone of protection (ZOP) with known conductor types and assumes homogenous performance across the ZOP. Current processes do not establish specific locations where fault events occur, but are reconciled to the device that protects the ZOP. To establish the recorded effectiveness, PacifiCorp queried pre- versus post-installation performance with risk event drivers for all ZOPs having CC (specifically spacer cable construction). It was important to recognize that legacy projects were focused on reliability and thus did not require reconductoring of the entire ZOP. As such, the recorded effectiveness calculations accounted for the percentage of the ZOP that wasn't reconductored. The smaller the percentage of the ZOP the less the confidence of the recorded effectiveness, while the higher the percentage of the ZOP the higher the confidence of the calculation.

PacifiCorp has also documented known contact-related events with CC. As shown in Figure 5 below, these events did not result in faults, wires down, or ignitions because spacer cable was deployed and provide examples of effectiveness in the field.

Figure 5: PacifiCorp Covered Conductor Effectiveness Examples

PacifiCorp will continue to monitor and track all faults on our CC circuits and track performance as compared to bare wire installs. PacifiCorp will also continue to collaborate in this working group to ensure we gather and share information from the other IOUs.

4.1.5 BVES

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a CC pilot program in Q2 2018 and completed it in Q3 2019 using two different type of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then, BVES started the cover conductor WMP in late 2019 with plans to cover 4.3 circuit miles on 34.5 kV over the next 4 years and 8.6 circuit miles on 4.16 kV over the next 10 years. As of end of Dec. 2022, BVES has covered approximately 34 miles between its 34 kV and 4 kV systems.

In Q3 2018, BVES started a new tree-trimming contract with a new tree service contractor. BVES has been very aggressive with its vegetation manage program having up to four tree crews or more at a time to complete its three-year cycle and remediating any issue trees which has helped reduce outages from vegetation contacts. As of end of 2021, BVES has completed its vegetation three-year cycle and in 2022 has started a new three-year cycle vegetation manage program.

As part of its wildfire mitigation efforts, in June 2019, BVES began replacing all explosion fuses in its service area with Trip Savers and Elf Fuses. BVES completed this project in May 2021, which eliminated the potential for ignitions from explosion fuses.

Though 2022, BVES has still not had any outages, wire down, tree limbs and/or ignitions on the lines that have been covered. BVES is still in the early stages of its CC program. As more areas are covered and as more time passes, BVES will compile more recorded data to inform on the effectiveness of CC. The Table 5 below provides a simple assessment of recorded outages since 2016 and through 2022.

Table 5: BVES Recorded Outages (2016-2022)

Year	# of Outages
2016	75
2017	95
2018	34
2019	26
2020	57
2021	46
2022	52

4.1.6 Liberty

Liberty's CC program is relatively new, having begun in 2020. Because the program is new, data on the performance of CC effectiveness do not yet demonstrate meaningful recorded effectiveness results based on the limited sample period and the wide variations in weather conditions from year-to-year. In addition, the CC projects completed thus far represent a small percentage of each circuit's total line miles.

Based on a review of Liberty's Outage Management System (OMS) data, there have been zero reported outages or ignitions caused by an event on CC spans. The only known event that occurred on a CC span, in a spacer cable configuration, happened during a winter storm in early January 2023. The event did not create an outage or ignition and it was found as a result of a post-storm aerial patrol. In this incident, a tree fell across a spacer cable span that was installed in 2020. The tree pulled down the span and caused three poles to lean significantly; however, the messenger wire held up the tree and prevented a fault and a wire from falling to the ground. Figure 6 and Figure 7 below represent this one incident.

Figure 6: Liberty Spacer Cable System Preventing a Fault – Viewpoint 1

Figure 7: Liberty Spacer Cable System Preventing a Fault – Viewpoint 2

Upon finding the damage, the poles were reset to vertical and the damaged support brackets were replaced. No damage was found related to the conductor.

Liberty intends to continue to monitor CC effectiveness and reinforce the need to collect and highlight any events that occur on CC. As more CC is installed and is in service for a longer period of time, the data collected will become more meaningful.

4.2 Next Steps

In 2023, the utilities will continue meet on a regular basis, provide updates on risk event recorded data, discuss the methods used to measure the effectiveness of CC in the field, and continue to work towards developing consistent methods to measure the effectiveness of CC for better comparability. The utilities also plan to discuss outage data, causation identification and reporting. These efforts will require SME discussions and review of outage, wire-down and ignition data across the utilities. The utilities will also document any lessons learned.

5 Alternatives

5.1 Overview

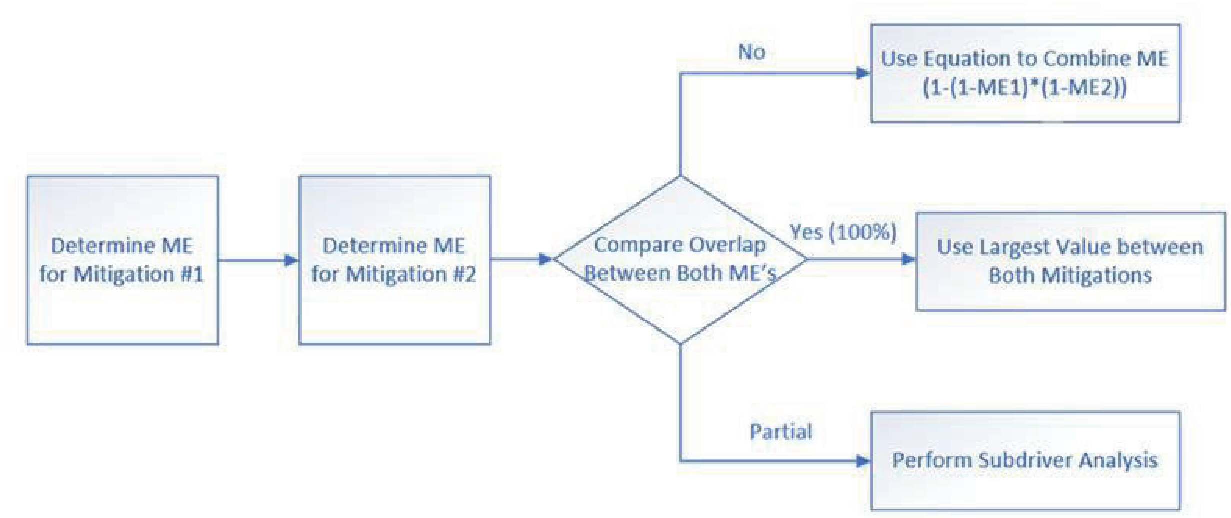
In the 2022 WMP Update filings, the utilities identified a list of viable alternatives to CC and conducted workshops with SMEs that assessed the effectiveness of those alternatives against the same risk drivers that CC is designed to mitigate. In 2022, the utilities focused on the combination of mitigations utilities deploy as it relates to CC and alternatives to CC and discussing a framework to calculate the effectiveness of the combination of mitigations deployed on the same circuit or circuit-segment. Below, we describe these efforts and plans for 2023 to further this workstream.

5.2 Combination of Mitigations:

The combination of mitigations refers to the suite of mitigations utilities deploy in relation to CC and alternatives to CC on circuits or circuit-segments to mitigate wildfire risk and/or reduce the impacts of PSPS. For example, all utilities deploy CC and where CC is installed all utilities conduct vegetation management mitigations and asset inspection mitigations. Additionally, circuits that have CC are still in scope for potential PSPS and most utilities also employ fast curve settings on these circuits during elevated fire-weather conditions. Likewise, several utilities deploy undergrounding to mitigate wildfire risk and PSPS impacts and where circuits are undergrounded, vegetation management mitigations are significantly lessened if not eliminated, the potential for PSPS is in most cases eliminated, and asset inspection mitigations can also be reduced. Notwithstanding system configuration, geography, terrain, permitting, costs, the time to deploy, operational/resource constraints, environmental constraints and other considerations, utilities can choose to install CC or other mitigations such as traditional hardening, new bare conductor, undergrounding, a remote grid, and/or new technologies to mitigate wildfire risk and/or reduce the impacts of PSPS. In choosing between CC and alternatives to CC, utilities will also deploy other mitigations. As such, the utilities understand the need to explore methods to assess the effectiveness of a combination of mitigations.

Historically, utilities have largely estimated the effectiveness of mitigations separately. The utilities have discussed methods to calculate the effectiveness of multiple mitigations deployed on the same circuit or circuit-segment. In 2022, the utilities discussed efforts to perform such a combination of mitigations calculation. While PG&E and SDG&E have not yet adopted a framework for this evaluation, SCE shared its preliminary framework (Figure 8) to calculate the effectiveness of a combination of mitigations.

Figure 8 SCE Preliminary Framework – Calculation of a Combination of Mitigations



SCE's preliminary framework includes three prongs given that mitigation measures can target the same or different risk drivers. For example, CC is highly effective at reducing most contact-from-object sub-drivers such as light vegetation contact, animal contact, and metallic balloons. However, CC is not highly effective at reducing faults/ignitions from large trees that can fall into lines. The framework thus distinguishes the overlap of multiple mitigations. In the first prong, if multiple mitigations have no overlap in the risk drivers they mitigate, a standard equation can be used to calculate the combined effectiveness, as seen in Figure 8. In the second prong, SCE considers where mitigations directly overlap with one another for a particular risk driver. In these instances, the mitigation with the highest effectiveness would be the combined effectiveness value. In the third prong, SCE considers where mitigations may target the same risk driver but they reduce the risk differently. In these situations, further analysis is needed to determine the incremental effectiveness prior to then combining the effectiveness values. Additionally, once the effectiveness of combined mitigations by driver are calculated, those values then need to be applied to the frequency of the driver risk events. Given that these estimated values are based on calculations and quantitative data can be limited and not always available, the utilities have also discussed discounting the individual estimated mitigation values.

To illustrate this framework, we use a subset of SCE's CC++ portfolio mitigation strategy. CC++ represents deploying CC, vegetation management, asset inspections, and other mitigations on the same circuit / circuit-segment that work collectively to better address the risk drivers than each by themselves. The tables and descriptions below are based on assessing the combination of CC, asset ground inspections, enhanced line clearing, pole brushing, and SCE's HTMP.

Table 6 shows independent estimated mitigation effectiveness values for the selected mitigations across selected contact-from-object and equipment failure sub-drivers. For purposes of this illustration, no discounting of individual estimated mitigation values was included.

Table 6: SCE Independent Mitigation Effectiveness Values

Risk Driver Description	WCCP	Distr Ground Asset Inspections	VM - Hazard Tree	VM - Expanded Pole Brushing	VM - Expanded Line Clearing
Animal contact- Distribution	65%	48%	0%	0%	0%
Balloon contact- Distribution	99%	0%	0%	0%	0%
Other contact from object - Distribution	77%	0%	0%	0%	0%
Unknown contact - Distribution	80%	0%	0%	0%	0%
Veg. contact- Distribution	71%	77%	64%	33%	36%
Vehicle contact- Distribution	82%	0%	0%	0%	0%
Capacitor bank damage or failure- Distribution	20%	87%	0%	20%	0%
Conductor damage or failure — Distribution	82%	80%	0%	7%	0%
Switch damage or failure- Distribution	2%	76%	0%	20%	0%
Transformer damage or failure - Distribution	20%	66%	0%	20%	0%

Using the risk driver vegetation contact, Table 6, above, shows varying estimated effectiveness values for WCCP, asset inspection, HTMP, expanded pole brushing, and expanded line clearing. All these mitigations work together to reduce the risk of vegetation contact causing a fire. For example, though CC addresses vegetation making contact with wires, line clearance and HTMP activities are also necessary to reduce heavy branches or trees falling into lines that CC may not be able to withstand. Asset inspection work assures equipment is in good condition, covers are in place, and if abnormalities are found, these are scheduled for remediation. These inspections also identify where vegetation may be in contact with equipment and conductors. While CC has shown, in the field, that there are times where it can withstand a large limb / tree fall-in and not create an outage and/or ignition, CC is not designed to withstand tree fall-ins. As such, and for purposes of this illustration, it is assumed these two mitigations do not overlap. Using the formula, described above, these two mitigations have an estimated combined mitigation effectiveness of approximately 90% (1-(1-71%)*(1-64%)). Asset inspections, expanded pole bushing, and expanded line clearing all have overlaps with CC for mitigating vegetation contact and thus require separate analyses. For purposes of this illustration, we assume these mitigations provide an approximate 9% incremental effectiveness for reducing vegetation contact risk. Combining all these values provides an estimated approximately 99% effectiveness value for risk of vegetation contact when all five mitigations are deployed on the same circuit / circuit-segment.

Following the same process, Table 7, below, shows the illustrative combined effectiveness values without considering quality control discounts. Additionally, applying the average annual frequency of historic faults and ignitions for these risk drivers, Table 7 shows the combined weighted average estimated effectiveness value for the selected mitigations.

Table 7: SCE Combined Mitigation Effectiveness Values

Risk Driver Description	Combined Effectiveness	Annual Fault Frequency in HFRA (2015-2020 Avg)	Fault-Weighted Combined Effectiveness	Annual Ignition Frequency in HFRA (2015-2020 Avg)	Ignition-Weighted Combined Effectiveness
Animal contact- Distribution	71%	644	6%	4.8	12%
Balloon contact- Distribution	99%	866	11%	5.0	17%
Other contact from object - Distribution	77%	420	4%	1.7	4%
Unknown contact - Distribution	80%	0	0%	0.0	0%
Veg. contact - Distribution	99%	469	6%	4.7	16%
Vehicle contact - Distribution	82%	550	6%	3.7	10%
Capacitor bank damage or failure- Distribution	92%	382	4%	0.2	1%
Conductor damage or failure - Distribution	85%	2,280	24%	8.3	24%
Switch damage or failure - Distribution	82%	58	1%	0.0	0%
Transformer damage or failure - Distribution	78%	2,334	23%	1.3	4%
Total Estimated Combined Effectiveness			84%		86%

In this illustration, Table 7 shows that when you combine WCCP with asset inspections, HTMP, expanded pole brushing, and expanded line clearing, the combined estimated effectiveness in mitigating faults and ignitions for the selected risk drivers and without discounting is approximately 84% and 86%, respectively.

Understanding the effectiveness of the combination of mitigations can be a helpful guide in utility decision-making. A common framework could also assist in greater comparability across the utilities. Challenges to developing such calculations include data availability, disaggregating effectiveness below the driver/sub-driver level to determine mitigation overlaps, and limitations in a purely formulaic method.

5.3 Next Steps

In 2023, the utilities will meet regularly to discuss methods to determine effectiveness for the combination of mitigations. This will include building on the preliminary framework described above by detailing examples across the utilities. Because many mitigations overlap with one another and can reduce a driver of a risk event differently, the utilities will also discuss and share available data and analytical methods to determine these differences. Additionally, the utilities will explore the process to develop suites of mitigation measures that include new technologies in continuing to evaluate methods to calculate the effectiveness of a combination of mitigations.

6 New Technologies

6.1 Introduction

In the utilities' 2022 WMP Update Action Statements, Energy Safety identified an ACI for all utilities to collaborate to evaluate the effectiveness of new technologies supporting grid hardening and situational awareness such as REFCL and DFA/EFD, particularly in combination with other initiatives. The utilities were also ordered to share practices and evaluate implementation strategies and that this effort should be a continuation of the CC study from the 2021 WMP Action Statements, including Energy Safety as a participant. Below, we outline the utilities' approach, information gathered to date, and 2023 milestones to assess the effectiveness of new technologies and share practices and implementation strategies.

6.2 Summary of Approach

The utilities initiated this workstream in Q4 2022 and have since conducted bi-weekly meetings. The initial meetings focused on identifying utility SMEs, discussing types of alternative technologies employed by the utilities, the status of those technologies, effectiveness values, approaches to sharing practices and implementation strategies and how to meet the ACI requirements, timelines/milestones. Evaluating the effectiveness of the technologies in combination with other mitigations is addressed in the scope for the Alternatives workstream, as described in the section above. Based on these initial discussions, it was first decided to document the various alternative technologies the utilities are employing. As seen below, very few technologies are employed across all utilities. The utilities then generally discussed effectiveness values and whether the new technologies can help reduce the impact of PSPS. It was learned that the majority of new technologies are still undergoing investigation and have limited data regarding effectiveness values. The utilities also discussed practices of how the technologies are being employed and learned that where utilities all employ a technology such as disabling reclosing settings, the practices are not all consistent. These areas of focus are further described below along with 2023 plans to conduct regular meetings and workshops focused on specific technologies. Beyond assessing the new technologies, the utilities also plan to document questions for benchmarking with other utilities and discuss any new research and/or other new technologies that the utilities are made aware of.

6.2.1 New Technologies

The utilities have identified 15 new technologies that one or more utilities employ, are piloting, and/or investigating. These include, for example, disabling reclosing settings, fuse replacements, fast curve settings, RAR/RCS, DFA, EFD, REFCL, and OPD. Table 8, below, identifies the new technologies or protection strategies being employed, piloted, and/or investigated to either mitigate wildfire risk and/or reduce the impacts of PSPS.

Table 8: New Technologies by Utility

New Technology / Protection Strategy	SCE	SDG&E	PG&E	Liberty	BVES	PacifiCorp
Fuse replacement (current limiting fuses, expulsion fuses)	Yes	Yes	Yes	Yes	Yes	Yes
Reclosing Settings (Disabling)	Yes	Yes	Yes	Yes	Yes	Yes
Fast curve settings / EPSS / SRP	Yes	Yes	Yes	Yes	No	Yes
Remote Controlled Automatic Reclosers / Remote Controlled Switches (RAR/RCS)	Yes	Yes	Yes	Yes	Yes	Yes
Distribution Fault Anticipation (DFA)	Yes	Yes	Pilot - Moving to Deployment	Investigating	No	Pilot
Early Fault Detection (EFD)	Yes	Yes	Pilot	No	No	No
Rapid Earth Fault Current Limiter (REFCL)	Pilot - Moving to Deployment	No	Pilot	No	No	No
Open Phase Detection (OPD)	Yes	No	Yes	No	No	No
Falling Conductor Protection (FCP)	No	Yes	Pilot	No	No	No
Smart meter (MADEC)	Yes	Yes	Yes	No	No	No
Household Outlet	Pilot	No	Pilot	No	No	No
Sensitive ground fault detection (relays)	Pilot	Yes	Yes	No	No	No
Electrical Grid Monitoring (EGM)	No	No	No	No	Pilot	No
Thor Hammer	No	No	Pilot	No	No	No
Intumescaent wrap / Fire-wrap poles	Yes	No	Yes	No	Yes	Yes

As seen in Table 8, there are only three types of new technology or protection strategies employed by all utilities. These include fuse replacements, disabling reclosing settings, and RAR/RCS. The other technologies are either being deployed, piloted, and/or investigated by a few utilities. Two technologies, DFA and REFCL, are moving from a pilot phase to deployment for PG&E and SCE, respectively. The utilities will further discuss the differences of these technologies to understand overlaps and similarities. For example, OPD and FCP have a similar purpose.

6.2.2 Practices and Implementation Strategies

The utilities have started to share practices for the new technologies. For example, while all utilities disable reclosing settings to mitigate wildfire risk, utility practices vary. For instance, SCE, PG&E and Liberty disable reclosing settings on circuits in HFRA during fire season, SDG&E disables settings, also on circuits in HFRA, but does it year-round, and BVES disables from April to October. The utilities believe that focused meetings and workshops on specific technologies are needed to share practices and implementation strategies. As such, the utilities will conduct focused workshops for specific technologies, as described below, to determine if best practices can be identified and will continue to share practices and implementation strategies in bi-weekly meetings.

6.2.3 Effectiveness Values

In many instances, the utilities are still investigating or have limited data as it relates to effectiveness values. The utilities have documented and shared effectiveness values for a few technologies but have not yet discussed these in detail. For example, effectiveness values for fast curve settings (when operating) range from approximately 49% to 100% effective at reducing ignitions (based on limited data that is not statistically significant). Given the large range, the utilities will conduct a workshop on the effectiveness of fast curve settings to share data and methods. Additionally, the utilities will discuss whether the technologies help reduce the impact of PSPS. As described in the next steps, the utilities have identified certain technologies for workshops and will continue to document estimated effectiveness values and the potential to reduce PSPS across all technologies.

6.3 Next Steps

In 2023, the utilities will continue to document and assess the estimated effectiveness of new technologies where data is available, their ability to reduce PSPS impacts, and will continue to document and share practices and implementation strategies. These objectives will be accomplished through biweekly meetings and a series of workshops. Based on discussions to date, the utilities provide the following preliminary workshop schedule and themes.

- April 2023 – Disable Reclosing Settings – Discuss practices and effectiveness
- May 2023 – Fast Curve Settings – Discuss practices and effectiveness
- June 2023 – DFA – Discuss implementation strategies, practices and effectiveness
- July 2023 – EFD – Discuss implementation strategies, practices and effectiveness
- Aug 2023 – REFCL Discuss implementation strategies, practices and effectiveness

Once the utilities finalize the workshop schedule, Energy Safety will be invited. Additional workshops may also be scheduled in Q3/Q4 2023. Should the results of the workshops lead to best practices, the utilities will establish plans to implement the changes and document as part of lessons learned.

7 M&I Practices

7.1 Introduction

In the utilities' 2022 WMP Update Action Statements, Energy Safety identified an ACI for all utilities to share and determine best practices for inspecting and maintaining CC, including either augmenting existing practices or developing new programs, to include this effort as part of the Joint IOU Covered Conductor Working Group, and for the IOUs to continue to lead this study and to include Energy Safety as a participant. Below, we outline the utilities' approach, information gathered to date, and 2023 milestones to assess the utilities' CC M&I practices, determine if best practices can be identified, and if best practices can be identified, put in place plans to implement those best practices.

7.2 Summary of Approach:

The utilities initiated this workstream in Q4 2022 and have since conducted weekly meetings. The initial meetings focused on identifying utility SMEs, discussing approaches to determine best practices and how to meet the ACI requirements, and timelines and milestones. Based on these initial discussions, the utilities agreed to a common approach that is both broad and focused. The approach includes first capturing information such as each key utility facts (e.g., service area size in HFRA), types of inspections utilities perform on distribution overhead conductor, general M&I practices for distribution overhead conductor, specific practices for CC, general and specific training the utilities conduct, and QA/QC information. Capturing broad information such as the types of inspections utilities perform provides a high-level understanding of how each utility performs inspections, the frequency it performs them at, and other related information. In assessing these sets of information, the utilities believe the determination of best practices will require a series of focused workshops and follow up meetings with SMEs, engineers, inspectors, QA/QC personnel and other resources as needed. Focused workshops are needed to facilitate determining if best practices can be identified. For example, all utilities perform ground and aerial inspections which are generally conducted similarly; however, they are not all performed the same way. Determining a best practice relating to performing a ground and/or aerial inspection for CC will require detailed discussions focusing on very specific aspects of the resources that do the work, tools and equipment used, the methods used, and other factors, some of which may only be obtained by conducting field observations across the utilities. It is also important to note that while there are differences in practices, determining best practices can take months, if not years, and that a best practice for one utility may not be a best practice for another utility for reasons such as costs, geographic size of the utility, and resource limitations. Given these facts, the utilities will also document any lessons learned that may be helpful for one or more utilities and can be added to existing M&I practices. Beyond assessing existing practices, the utilities also plan to document M&I-related questions for benchmarking with other utilities, learn from the testing workstream (should any CC inspection and/or maintenance practice be recommended from that workstream), and discuss any new research and/or new technologies that the utilities are made aware of as it relates to CC M&I practices.

7.2.1 Key Distribution Data

The joint utilities vary in size and it is important to consider this information when assessing best practices. Table 9, below, provides a few data points in HFRA, unless as otherwise noted, regarding the utilities' service area size, the facilities they maintain, and the average number of distribution inspectors. The figures in Table 9 are approximate values.

Table 9: Key Distribution Data by Utility

Key Data in HFRA	PG&E	SCE	SDG&E	PacifiCorp	Liberty	BVES
Distribution Overhead Circuit Miles	25,200	9,600	3,400	813	676	211
Distribution Poles	630,000	290,000	81,000	20,378	23,058	8,860
Square Miles	41,000	14,000	2,600	7,155	938	32
Average Number of Ground Inspectors (Systemwide)	203	153	50	5	4	2

As illustrated in Table 9 above, PG&E has significantly more square miles, distribution overhead circuit miles, and distribution poles in its HFRA to inspect and maintain. Conversely, BVES has the smallest HFRA square miles and least amount of distribution overhead circuit miles and distribution poles to maintain and inspect. As described more below, due to HFRA size alone, a best practice at PG&E may not be an ideal practice for BVES and vice versa.

7.2.2 Types of Distribution Inspections

The utilities perform several types of inspections on distribution facilities. These include detailed ground inspections, aerial inspections, infrared, patrols, Areas of Concern (AOCs) and LiDAR. These distribution inspection types are designed to meet or exceed GO 95 and GO 165, and also to mitigate wildfire risk. Table 10 and Table 11 below highlight the types of distribution inspections the utilities perform.

Table 10: Types of Distribution Inspections performed by SCE, PG&E and SDG&E

Types of Distribution Inspections	SCE	PG&E	SDG&E
Detailed - Ground	Every distribution structure inspected between twice a year and up to once every 3 years, and high-risk structures inspected at least every year; Inspectors on the ground can use binoculars and/or cameras when needed	HFTD: Structures inspected every 1-3 years based on wildfire consequence; Top 10% risk structures inspected every year; Non-HFTD: every 5 years Inspectors use binoculars when needed	Every distribution structure inspected every 5 years
Detailed - Aerial	Every distribution structure inspected between twice a year and up to once every 3 years, and high risk structures inspected at least every year; SCE does 360 degree inspection from ground and the air with the same resources (drone) in the same time period	Will cover ~48K distribution structures in 2023 in the highest wildfire consequence areas; Longer-term plan will be developed based on the learnings from 2023 drone program	Drone inspections are performed on high-risk assets each year; Risk assessment performed annually to determine scope of assets to be inspected that year; Approximately 15,000 structures inspected per year.
Infrared	5,100 distribution overhead circuit miles targeted for inspection in 2023; performed on the ground	Conducted at high risk locations on an ad hoc basis	18,000 structures per year; plus ad hoc based on cause-unknown outages; Combination of aerial and ground
Patrol	100% of above ground and subsurface assets inspected annually; Conducted by ground mostly and helicopter/drone if needed (e.g., access issues)	HFTD: 100% of assets that are not inspected each year Non-HFTD: Based on urban/rural designations	100% of assets inspected annually
Areas of Concern (AOCs)	Additional inspections based on area of concern analysis conducted in late spring / early summer	Additional inspections are performed in areas of concern when needed.	See drone inspections - areas of concern determined by risk assessment and these are performed via drone
LiDAR	In 2023, will evaluate the use of this technology for asset-condition assessments; Historically, used for construction, planning, crew access, vegetation, etc.	Utilized to update pole orientation and associated attributes such as communication line, guy, anchor Database is then leveraged to conduct pole loading assessment to identify overloaded poles for replacement	Only utilized for construction planning purposes

Table 11: Types of Distribution Inspections performed by PacifiCorp, BVES, and Liberty

Types of Distribution Inspections	PacifiCorp	BVES	Liberty
Detailed - Ground	Every distribution structure inspected every 5 years; Inspections on ground use cameras and binoculars	Every distribution structure inspected every 5 years	Every distribution structure inspected every 5 years
Detailed - Aerial	Every distribution structure is inspected every year in Tier 2/3 areas and every 2 years in non-Tier areas; Inspection is performed from the ground with same resources in the same time period	Contractor performs drone inspections yearly with infrared on 100% of 34 kV and 4 kV distribution circuits	No aerial inspections on distribution at this time.
Infrared	Only when requested	100% of 34 kV and 4 kV distribution circuits per year	No infrared at this time
Patrol	100% of assets inspected annually	100% of assets inspected annually	100% of assets inspected annually
Areas of Concern (AOC)	Additional inspections performed when requested	May complete addition patrol inspection during extreme dry day with possible high fire risk	Additional inspections are performed in areas of concern when needed
LiDAR	Not performed on distribution circuits, but has been used in the past for vegetation	Use yearly for vegetation management (Check to see if vegetation is near lines)	Use for vegetation management

As shown in Table 10 and Table 11 above, the utilities perform similar types of inspections. Given the requirements of GO 95 and GO 165, this was to be expected. There are differences, however, in some inspection types as well as in some practices. For example, not all utilities conduct detailed ground inspections on high-risk / high consequence structures (and conductor) every year. Being that the focus of this effort is on CC M&I practices, obtaining findings for CC during these inspections and discussing amongst the utilities will help inform if a best practice can be identified and whether that best practice should and can be applied to all utilities. Similarly, some utilities conduct Areas of Concern (AOCs) inspections and SCE is evaluating LiDAR for asset condition assessments, which has historically been used for vegetation clearances and construction-related purposes. The utilities will discuss these types of inspections, focused on CC, and assess how useful they are in maintaining CC to determine if they should and can be utilized across all utilities.

7.2.3 General M&I Practices

Because utilities have performed inspections and remediation on overhead facilities for decades, the utilities have shared and discussed various aspects of what inspectors look for when assessing the condition of overhead conductor, regardless if covered or bare (as most assessments for bare will also apply to covered). For example, during detailed ground inspections, inspectors will assess (naked eye and/or binoculars) all components and equipment attached to a pole and any materials connected to conductors. These inspections look for deterioration/corrosion, pitting, damage, clearance issues, sagging, loading, alignment issues (e.g., dead-end covers), misconfigurations, conformance with construction standards (e.g., missing covers/guards), exposed sections for splices, connectors, vegetation in immediate need for remediation, and other abnormal conditions. All of these potential issues apply to bare and CC. In large part, many of the methods and potential issues inspectors look for with bare conductor equally apply to CC. Given this fact, it is important to understand the general M&I practices for overhead conductor that utilities use. The utilities will also explore determining abnormal conditions that could cause a safety or fire ignition risk resulting in remediation and how these are prioritized. Additionally, inspectors that perform this work have understanding and knowledge that can inform the assessment of potential best practices and the utilities intend to include these resources in the workshops. The utilities will continue to discuss and document these practices and prepare for workshops to determine if best practices for CC can be determined.

7.2.4 Specific M&I Practices

This category refers to specific M&I practices for CC. SCE has shared its specific M&I practices which include prompts for data accuracy including types of CC and directions CC is installed, construction standard checks including any missing items such as dead-end covers, connector covers, fuse covers, lightning arrestors and covers, and pothead covers, and identifying abnormal conditions such as visible signs of tracking or damage on the outer jacket. Additionally, in 2023, PG&E updated their Detailed Ground Inspection checklist to include prompts for identifying failure modes that are unique to CC such as CC wire jacket cut into and bare conductor exposed, CC exposed and burnt, and dead-end cover mis-aligned on CC construction. While other utilities may not have tools that have these specific prompts, as part of their training, they look for visible signs of tracking and/or damage on the covering as well as discoloration. As noted above, the majority of M&I practices for bare conductor apply to CC. Because damage to the outer layer of CC may lead to faults/failures, this is an important inspection assessment all utility inspectors perform. Likewise, all utility inspectors are trained on their CC construction standards and thus assess conformance to the construction standard in the field. Most utilities do not collect asset information for data quality checks as some SCE prompts provide for; however, if deficiencies are noted during other utilities' inspections, they can be submitted through their processes. The utilities will assess these details in workshop settings to determine if best practices can be identified. Field observations may also be conducted to capture additional information.

7.2.5 Training

All utility inspectors are trained to understand CC construction standards and maintenance of CC through new inspector training, refresher training, ad hoc training and/or training conducted by the conductor manufacturer or through industry partners. The large utilities have similar types of training including new inspector training, refresher training, and ad hoc training for changes to standards, materials, etc. that may occur. The small utilities have few inspectors and typically are trained linemen with 20+ years' experience. These inspectors are trained on CC through industry organizations and/or the manufacturer as opposed to through a utility-developed training curriculum. For example, BVES has two inspectors that are trained lineman with over 20 years' experience. As such, developing a training curriculum for two inspectors may not be cost-effective when alternative training through the manufacturer or industry partner is available. The utilities will continue to collect training information and conduct a workshop to determine any best practices.

7.2.6 QA/QC

All utilities employ a quality assurance / quality check (QA/QC) process for asset inspections as well as construction of CC lines. For example, the large utilities will QA/QC CC as part of their QA/QC program, which are based on sampling methods. BVES and Liberty QA/QC all CC installations. Given the difference in size of utilities, it makes sense that the large utilities use QA/QC sampling methods whereas the small utilities QA/QC all new CC work. The utilities will further discuss and assess each utilities QA/QC practices related to CC in a workshop setting to determine if best practices can be identified.

7.3 Next Steps

In 2023, the utilities will continue to capture general and specific CC M&I practices across the utilities and will conduct workshops to determine if best practices can be identified. Meetings will also be held to follow up on the workshops and set plans to implement any best practices that are identified. Below, the utilities provide a preliminary workshop schedule and themes.

- April 2023 – General conductor and specific CC M&I practices
- May 2023 – General conductor and specific CC Training
- June 2023 – QA/QC of CC
- July 2023 – Recommendations from Testing Results
- Aug 2023 – Inspection Types and Tools Used

Once the utilities finalize the workshop schedule, Energy Safety will be invited. Additional workshops may also be scheduled if needed. Should the workshops lead to best practices, the utilities will establish plans to implement the changes and document as part of lessons learned.

8 Estimated Effectiveness:

8.1 Overview

As explained in the 2022 WMP Update report, each utility's CC programs are different due to factors such as location, terrain, and existing overhead facilities. The utilities also have different frequencies of risk drivers. Additionally, the utilities are still at different phases of installing CC as some have limited miles deployed while others have deployed thousands of miles of CC. These features, amongst others, result in data, calculations, and methods of estimating effectiveness that are different. As such, the utilities have been working on understanding differences and discussing methods for better consistency. In 2022, the utilities focused on testing, recorded effectiveness, and the new requirements. The utilities' continue to estimate CC effectiveness from approximately 60 to 90 percent at reducing outages/ignitions and/or the drivers of wildfire risk.

Below, the utilities describe any updates to their data, analyses, and methods used to estimate the effectiveness of CC to mitigate outages/ignitions and/or the drivers of wildfire risk and present their estimated effectiveness values, and describe next steps to improve consistency of data, calculations and methods.

8.2 Covered Conductor Estimated Effectiveness

8.2.1 SCE

SCE's Wildfire Covered Conductor Program (WCCP) consists of replacing bare conductor with CC, the installation fire-resistant poles (FRPs) where applicable, wildlife covers (animal safe construction), lighting arresters, and vibration dampers below 3,000 feet. Additionally, in 2022, SCE modified its CC construction standard to include the replacement of open wire secondary or weather-resistant aluminum (OWS or WAL) with multiplex secondary conductors. Weather resistant aluminum wire on the secondary system are outdated technology and will be updated to the new standard when WCCP is installed. Because this standard update will only affect WCCP installations starting in 2024, and not WCCP completed in 2022 or planned for 2023, This activity is not yet accounted for in determining the overall mitigation effectiveness of SCE's WCCP.

In 2022, SCE assessed the Joint IOU testing results and mapped the test results to risk drivers and sub-drivers to determine if any changes were warranted. Results from the Wire Down Event Scenarios demonstrate that the bare portion of the conductor must be exposed to lead to an ignition. The System Strength Tests demonstrates that tangent structures will not significantly damage the conductor enough to expose the bare conductor. Tangent structures without equipment do not have any exposed bare conductor or taps (~50% of all structures are tangent). As a result, the current mitigation effectiveness of Vehicle Contacts did not account for the performance of CC on tangent structures, therefore SCE increased the mitigation effectiveness from 50% to 82%. SCE also evaluated phase-to-phase contact and simulated wire-down testing. CCs were 100% effective at preventing arcing and ignition in tested scenarios at rated voltage, consistent Exponent's Phase I field reporting. Per the testing results, adjustments were also made for vegetation contact and unknown contacts. Below, SCE provides the updated estimated mitigation effectiveness for WCCP. Overall, the estimated mitigation effectiveness for WCCP increased from approximately 67% to 72%.

Table 12: SCE Covered Conductor Mitigation Effectiveness Estimate

Driver Type	Sub-Driver/ Consequence Type	% Drivers	Current Driver ME	New Drive ME	Directional Change	Indicative Test Result
D-CFO	Vegetation contact	12%	60%	71%	Increased	Wire Down Events + System Strength
D-CFO	Animal contact	13%	65%	65%	No Change	Wildlife cover test
D-CFO	Balloon contact	13%	99%	99%	No Change	
D-CFO	Vehicle contact	10%	50%	82%	Increased	Wire Down Events + System Strength
D-CFO	Unknown contact	8%	77%	80%	Increased	Aggregate of CFO Result
D-CFO	Other contact from object	3%	77%	77%	No Change	
D-WTW	Wire-to-wire contact / contamination	3%	99%	99%	No Change	
D-EFF	Conductor damage or failure	13%	90%	90%	No Change	Degraded covering
D-EFF	Connection device damage or failure	5%	90%	90%	No Change	
D-EFF	Connector damage or failure	5%	90%	90%	No Change	
D-EFF	Crossarm damage or failure	~0%	50%	50%	No Change	System Strength
D-EFF	Insulator and brushing damage or failure	4%	90%	90%	No Change	
D-EFF	Splice damage or failure	5%	90%	90%	No Change	

8.2.2 PG&E

PG&E's overhead hardening program consists of primary and secondary CC replacement along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers, framing and animal protection upgrades, and vegetation clearing. PG&E understands the focus of this request to be centered on CC, however our efforts to estimate effectiveness include all elements of our Overhead Hardening program, which PG&E believes is more complete.

Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination for each event, estimating overhead hardening effectiveness relies upon the following proxy to derive its estimates. Most distribution outages (momentary and sustained) typically involve a fault condition. Thus, for purposes of estimating overhead hardening effectiveness, it is assumed that all distribution outages could potentially result in an ignition, regardless of other prevailing conditions. This approach aligns with what has been previously stated in PG&E's 2020 WMP as well as its 2020 RAMP filing.

In early 2023, PG&E assessed the Joint IOU testing results to re-evaluate the SME effectiveness designations and adjusted the effectiveness in a few key areas. While this is expected to be an ongoing process, we have refreshed our effectiveness values based on updated designations and the data as follows:

- Tree fall-in associated with wire on object, and wire on ground, changed from "none" (not effective) to "medium" (some effectiveness). While other IOUs considered a higher effectiveness than PG&E, there are large enough trees in our service area that can damage CC and as such, CC does not have as substantial an increase in effectiveness.
- Contact from Object Vehicle changed from "none" (not effective) to "medium" (some effectiveness). We agree with other IOUs that this has some limited benefit. Given that we are installing larger poles to support CCs, the larger poles have the potential to sustain more impact from vehicle than existing infrastructure.
- Animal caused outages associated with conductor contact changed from "none' (not effective) to "All" (very high effectiveness). Testing on the covering material of the CCs showed a high resiliency to damage. Also, PG&E found that the insulating properties of the covering did not diminish significantly when damaged. Therefore, we have increased CC effectiveness for mitigating damage caused by animals like squirrels and birds.

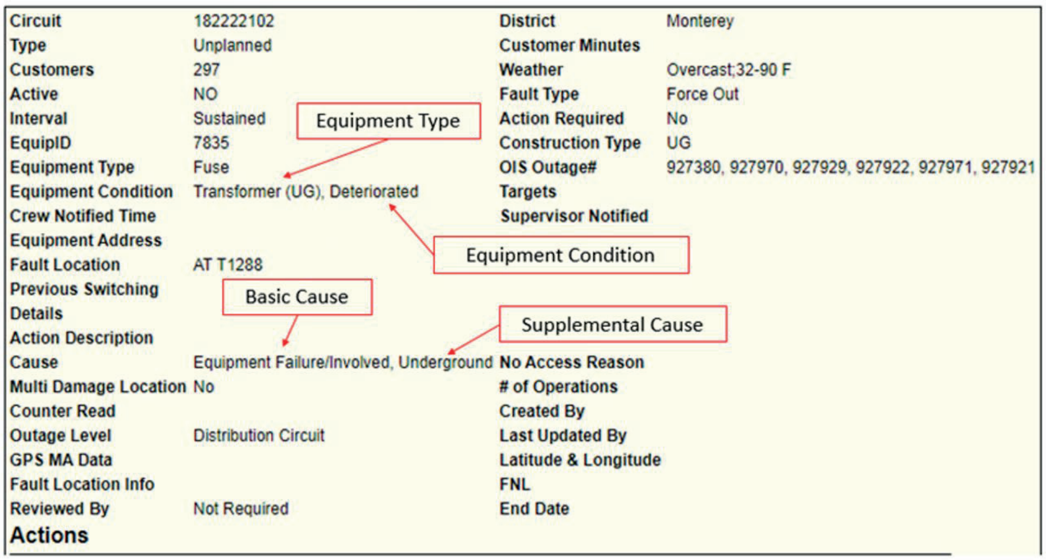
Additionally, PG&E has refreshed our data for estimated effectiveness to include outage data through 2022. Previously, the last PG&E update including outage data was from PG&E's 2023 GRC filing, which had data through 2020.

With the above assumptions from the PG&E's 2020 WMP as well as our 2020 RAMP filing, PG&E updated the estimated effectiveness factor for overhead hardening in 2023, incorporating the 2023 re-evaluated SME effectiveness designations:

1. SMEs identified ~80k distinct outages between 2016-2022 by using all known combinations of basic cause, supplemental cause, equipment type and equipment condition from the distribution outage database as show in Figure 9 below. Whenever an outage is reported, an

operator fills in different fields that provide information about the outage. Through SME evaluation, it was decided that a combination of the four aforementioned fields provide an appropriate distinction of different outage types.

Figure 9: PG&E Distribution Outage Database Record



Circuit	182222102	District	Monterey
Type	Unplanned	Customer Minutes	
Customers	297	Weather	Overcast;32-90 F
Active	NO	Fault Type	Force Out
Interval	Sustained	Action Required	No
EquipID	7835	Construction Type	UG
Equipment Type	Fuse	OIS Outage#	927380, 927970, 927929, 927922, 927971, 927921
Equipment Condition	Transformer (UG), Deteriorated	Targets	
Crew Notified Time		Supervisor Notified	
Equipment Address			
Fault Location	AT T1288		
Previous Switching Details			
Action Description			
Cause	Equipment Failure/Involved, Underground	No Access Reason	
Multi Damage Location	No	# of Operations	
Counter Read		Created By	
Outage Level	Distribution Circuit	Last Updated By	
GPS MA Data		Latitude & Longitude	
Fault Location Info		FNL	
Reviewed By	Not Required	End Date	
Actions			

2. Subject matter experts identified whether overhead hardening would eliminate, reduce significantly, reduce moderately, reduce minimally, or not affect the likelihood of a certain type of outage occurring leading to an ignition when an asset has been hardened. From this classification the following qualitative categorization was performed:
   - All = Eliminates likelihood of a certain type of outage occurring resulting in an ignition
   - High = Reduces likelihood significantly of a certain type of outage occurring resulting in an ignition
   - Medium = Reduces likelihood moderately of a certain type of outage occurring resulting in an ignition
   - Low = Reduces likelihood minimally of a certain type of outage occurring resulting in an ignition
   - None = Will not affect the likelihood of a certain type of outage occurring resulting in an ignition
3. Each qualitative category was assigned a quantitative value, which measured the likelihood of outage reduction:
   - All = 90%
   - High = 70%
   - Medium = 40%
   - Low = 20%

- None = 0%

4. The above criteria were applied to historical outages, and this resulted in the likelihood of outage reduction for each outage.
5. Outages were classified by drivers. The outage drivers identified were: Animal, D-Line Equipment Failure, Environmental/External, Third Party, Vegetation. The Wildfire Mitigation driver was excluded as it captures all PSPS triggered outages.
6. A Pivot table was then created to aggregate Outages in HFTD. The aggregation was done at the outage driver level and the result are shown below in Table 13.

Table 13: PG&E Covered Conductor Mitigation Effectiveness Estimate

Driver	Average Yearly Count of Incident ID	Average of SH_Effect_Pct
Animal	429	75%
D-Line Equipment Failure	2,233	69%
Environmental/External	255	42%
Third Party	397	57%
Vegetation	2,735	62%
Grand Total	6,049	64%

Based on the latest update using outage data through 2022 and repeating the process from PG&E's 2020 WMP filing, the updated estimated effectiveness is 64% where Overhead Hardening has been completed. Therefore, a section of a line that has been hardened is approximately 64% less likely to have an outage of any type. Similarly, a section of a line that has been hardened is approximately 64% less likely to have an outage of each of the drivers. This result is consistent with the previous results that were completed using data for the 2020 WMP.

8.2.3 SDG&E

SDG&E initially began to examine CC from a personnel safety and reliability standpoint. The three-layered construction showed prospective reduction of injuries to people in the event of an energized wire-down in which the wire contacted a person and/or also might reduce the step potential to people in the vicinity. Outages that result from light momentary contacts (i.e. mylar balloons, birds, palm fronds) also have shown the potential to be reduced. In late 2018, focus was shifted towards using CC as an alternative to SDG&E's traditional overhead hardening program with the primary focus of reducing utility-caused ignitions.

SME's conducted research on the history and use of CC in the industry. Additionally, the SMEs reached out to utilities on the East Coast and internationally to receive their feedback of the effectiveness and work methods for installation purposes.

In addition to other studies/tests that have been and will be performed by SCE and PG&E, as described in the Testing section, SDG&E will have a third-party evaluate the likelihood and effect specific to conductors clashing at various wind speeds. Accelerated aging studies will also be performed to mimic a

40-year service life; after which, the samples will be subjected to tests designed to understand the potential for both mechanical degradation, as well as reduction in dielectric strength. These tests will be performed in accordance with ASTM or other industry recognized standards. Final reports for this testing are expected to be completed in April 2023.

In order to quantify the risk reduction of wildfires that would be achieved by CC, SDG&E evaluated 80 events that resulted in ignitions. SMEs weighed in on the likelihood that CC installation would prevent an ignition for the particular type of outage depending on the severity of the incident. As seen in Table 14 below, the result is a reduction in ignitions from 60 to 20.6, and a resulting effectiveness estimate of 65.7%.

In 2022, SDG&E has been participating in collaborating with other utilities as part of the Joint IOU working groups in the evaluation of the testing that has been and is currently still being performed. Once all testing has been completed in 2023, SDG&E will perform an analysis based on risk drivers to re-evaluate the estimated efficacy of CC.

Table 14: SDG&E Covered Conductor Mitigation Effectiveness Estimate

Fault/Ignition Cause	Number of Ignitions	SME Effectiveness	Post-Mitigation Ignitions
Animal contact	7	90%	0.7
Balloon contact	9	90%	0.9
Vegetation contact	2	90%	0.2
Vehicle contact	8	20%	6.4
Other contact	3	10%	2.7
Other	4	10%	3.6
Equipment - All	26	80%	5.2
Unknown	1	10%	0.9
Total	60	65.7%	20.6

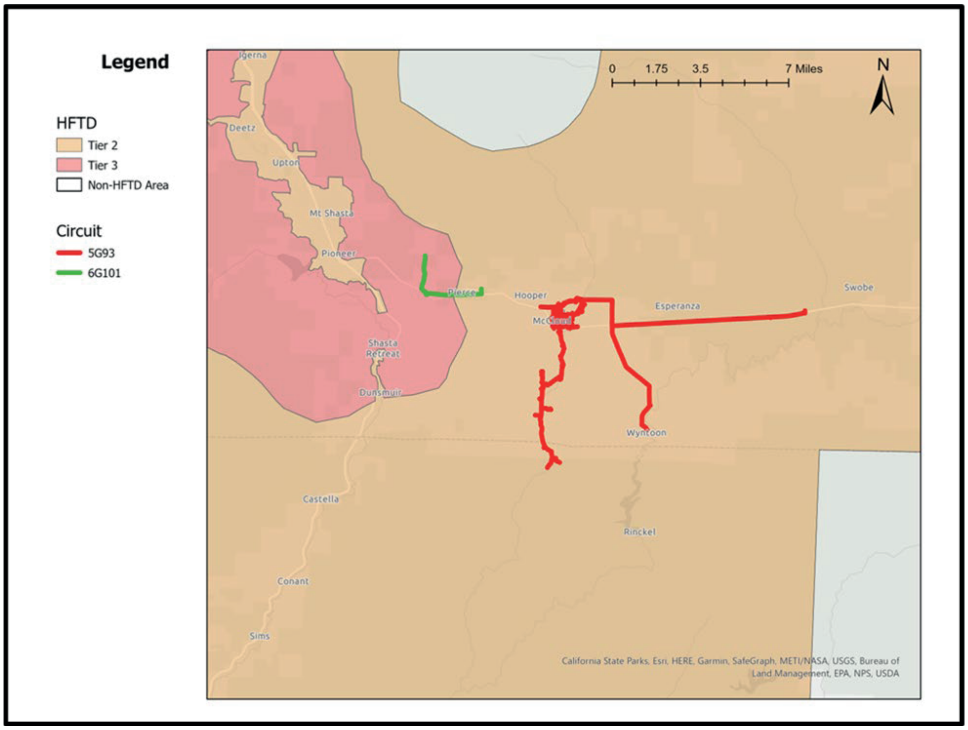
Table 14 above was updated with the number of ignitions occurring between 2017-2021 compared to last year's report that was based on 2016-2020 data. Updates to SDG&E's overall effectiveness methodology are anticipated to be completed by December 2023.

8.2.4 PacifiCorp

Prior to development of the WMP, PacifiCorp historically pursued CC designs and systems due to historical experience with elevated outage count from trees, limbs, and incidental contact (resulting in grow in) throughout its service area. Additionally, access conditions on some of its circuits are extremely difficult in certain times of the year, and those circuits also tend to have elevated outage rates. For the above-mentioned reasons, when siting its historic CC pilot projects, PacifiCorp tended to focus its deployment on circuit-segments that had above average vegetation and/or animal outage rates in conjunction with difficult access. Now, as part of the company's line rebuild program to install CC and mitigate wildfire risk, PacifiCorp is actively pursuing both CC and spacer cable systems. Most projects completed so far as part this program have leveraged a spacer cable system, which primarily includes CC, a structural member (messenger), and specialized attachment brackets. Therefore, the effectiveness examples and estimations were determined for spacer cable.

As an example of how to assess the effectiveness of newly installed spacer cable, PacifiCorp compared two circuits, one with bare wire and one with spacer cable installed. Both circuits are in the same general geographic area and shown in Figure 10 below. Additionally, the circuits are in a HFTD, with the spacer cable partially located in a tier 3 area near Mt. Shasta and the bare conductor located completely within a tier 2 area, though it is still located within a few miles of the tier 3 boundary.

Figure 10: PacifiCorp Map Showing the Two Circuits Plotted with the HFTD Overlay



To begin characterizing outage frequency variation prior to and after the installation of spacer cable, 18 years of outage data (2005-present) for both circuits was reviewed and is summarized in Table 15, below.

Table 15: PacifiCorp Outage Frequency for Bare Wire and Spacer Cable Circuits (2005 – present; Asterisk (*) indicates the year spacer cable was installed)

Year:	Outages - Bare Wire Circuit:	Outages - Spacer Cable Circuit (Q4 2021):
2005	8	0
2006	6	2
2007	2	2
2008	10	10

Year:	Outages - Bare Wire Circuit:	Outages - Spacer Cable Circuit (Q4 2021):
2009	0	0
2010	6	12
2011	42	18
2012	6	4
2013	10	2
2014	2	0
2015	2	2
2016	2	2
2017	2	4
2018	0	0
2019	4	2
2020	4	0
2021	2	4 *
2022	8	**0**
2023	4	**0**

Generally, the data demonstrates that outage frequency can significantly vary year over year. Additionally, in this example, the bare wire circuit has historically experienced either an equivalent or higher frequency of outages than the circuit the spacer cable was installed, except in 2010. While many factors can impact outages and reliability, this general trend is expected given the significant differences in circuit length. This same data was then normalized based on circuit mile and summarized in Table 16 below.

In Table 15 and Table 16, the data generally shows that for the spacer cable installation (completed in Q4 2021), there was a reduction in outages in all years following the rebuild project (0 for 2022 and 2023 so far). Additionally, the nearby bare wire circuit experienced a total of 12 outage events in 2022 and 2023 (as of January 2023). While certainly not conclusive or representative of a clear trend, the data does support that potential impact spacer cable can have on outage frequency.

A further analysis into outage causes for each circuit at the time of spacer cable installation was performed and included in Table 16 below. The table shows the spacer cable experienced 0 outages in 2022 and 2023 (as of January 2023) for all risk drivers. However, for the bare wire circuit, there was a total of 12 outages across all risk drivers, with trees being the main driver in 2022.

Table 16: PacifiCorp Risk Drivers for Bare Wire and Spacer Cable Circuits (2021 – present; Asterisk (*) indicates the year spacer cable was installed)

Year:	Risk Drivers:	Bare Wire Circuit:	Spacer Cable Circuit (Q4 2021):
2021	TREES	2	0 *
2021	LOSS OF SUPPLY	0	4 *
2022	TREES	4	**0**
2022	INTERFERENCE	2	**0**

Year:	Risk Drivers:	Bare Wire Circuit:	Spacer Cable Circuit (Q4 2021):
2022	PLANNED	2	**0**
2023	TREES	2	**0**
2023	WEATHER	2	**0**

While promising, this analysis is neither conclusive nor representative of a clear trend. Additionally, this individual analysis may not be representative of macro trends. The circuit that has the spacer cable is installed on only 6.1 miles which serves only 12 customers and has been in place since Q4 2021. Furthermore, PacifiCorp believes that determining the long-term effectiveness of CC, both in its ability to reduce wildfire risk and PSPS impacts, requires additional data and time. At a minimum, a longer history of outage data would be necessary to fully understand the impacts of the spacer cable.

8.2.5 BVES

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a CC pilot program in Q2 2018 and completed it in Q3 2019 using two different types of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then BVES started the cover conductor WMP in late 2019 with a plan to cover 4.3 circuit miles on 34.5kV over the next 5 years and 8.6 circuit miles on 4.16 kV over the next 10 years. As of the end of Dec. 2021, BVES has covered approximately 21.1 miles between its 34 kV and 4 kV systems. BVES' average span length is approximately 150 feet and installing CC on cross arms. As part of its CC program when there are spliced locations, BVES installs premade cold shrink kits (3M) and installs avian protection (raptor protection/wildlife guard).

Based on benchmarking with other utilities' estimated effectiveness against ignition risks, discussions with its CC supplier, and the short amount of time that it has installed CC, BVES continues to believe that the estimate of effectiveness on ignition risk drivers in its service area is approximately 90%. As BVES installs more CC and gathers more historical data, it will continue to assess the estimate of effectiveness. BVES presents its estimated effectiveness in Table 17 below.

Table 17: BVES Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Vegetation Contact	90% +	Vegetation contact on 1, 2, 3 phase and/or neutral wire.
Animal Contact	90% +	Animal contact on 1, 2, 3 phase and/or neutral wire.
Balloon Contact	90% +	Balloon contact on 1, 2, 3 phase and/or neutral wire.
Wire down contact	90% +	Due to the following: tree/tree limb fallen on line, car hit pole, wind gust, etc.
Vehicle Contact	90% +	Vehicle Contact due to wire down on vehicle.
Wire to Wire Contact	90% +	Due to the wind gust forces causing tree/tree limb fall on line or just wire to wire contact.

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Splice location contact	90% +	BVES installs Avian protection/raptor protection/wildlife guards and uses premade cold shrink kits (3M) on splice locations.
Vandalism/Theft	90% +	In BVES' service area there is a low risk of conductor theft as well as vandalism. If vandalism occurs, Ex. damage from "gunshot" to the conductor covering installed.
Lightning Contact	90% +	During raining seasons, sometimes encounter a good amount of lightning strikes in BVES' service area. BVES using priority covered conductor (flame resistant) cable.
Third Party	90% +	Third party including contact from joint use, boom arms, etc. should be mostly mitigated with covered conductor cable.
Flame Propagation along the covered conductor	90% +	Caused by Lightning or other.
Flame particle dripping	90% +	Caused by Lightning or other.

8.2.6 Liberty

The CC mitigation estimated effectiveness values for the various ignition risk drivers in 2023 remain unchanged from values in Liberty's 2022 WMP report update. The estimated effectiveness ranges from 95% for vegetation contact risk driver to 15% for lightning risk driver.

8.3 Next Steps

As detailed above, the utilities estimate the effectiveness of CC between approximately 60 and 90 percent. In 2023, the utilities will continue to meet on a regular basis to discuss estimated effectiveness methods, data and calculations. The utilities will learn from the testing, and recorded results and collaborate to improve each utilities' understanding and approach to estimate effectiveness. The utilities will also discuss opportunities to align data and methods for greater comparability and will document any lessons learned.

9 PSPS

9.1 Introduction

In the 2022 WMP Update report, the utilities described their general PSPS approach and how a CC system can reduce PSPS impacts, and provided an assessment of alternatives and their ability to reduce PSPS impacts compared to CC. As described in the 2022 WMP Update report, only SCE has increased PSPS thresholds for fully-isolatable circuit-segments that are covered in comparison to bare conductor. Other utilities, such as SDG&E, informed that circuits with CC could likely withstand higher wind speed tolerances; however, more real-world experience and studies would be required prior to increasing PSPS thresholds. As SDG&E completes construction and obtains this data, it will inform wind-speed tolerances for PSPS. Below, the utilities describe its efforts to better understand the ability of CC and alternatives to reduce the impacts of PSPS as well as plans for 2023 to further this effort.

9.2 Summary

In 2022, the utilities continued to meet and discuss CC and its ability to reduce the impact of PSPS. No utility made changes, per descriptions in last year's report, to their general PSPS practices and thresholds in 2022. The utilities did discuss studies being considered to further assess CC and other mitigations in their ability to reduce the impact of PSPS. Additionally, the utilities have recently discussed the testing results in relation to reducing the impact of PSPS. For example, SCE described how the testing results can provide boundary conditions/limits that enable more granular analysis. While other data such as improved understanding of local hazards are needed to fully inform of potential changes to PSPS thresholds, the testing results can help enable analyses that could provide additional benefits like changes in PSPS de-energization thresholds. SCE and SDG&E will be conducting studies to investigate different aspects and conditions of CC and local conditions to further inform potential changes to PSPS de-energization thresholds. Additionally, and as identified in the Testing workstream, the utilities will discuss the results of the testing in relation to PSPS de-energization thresholds in the testing workshops.

9.3 Next Steps

In 2023, the utilities will assess new technologies in their ability to reduce PSPS impacts as part of the New Technology workstream. Additionally, the utilities will discuss the testing results to further inform PSPS de-energization thresholds as part of the testing workshops. The utilities will also regularly meet to assess the status of related studies and discuss any changes to PSPS practices. If changes to PSPS de-energization thresholds are made and/or to general PSPS practices, the utilities will document any lessons learned.

10 Benchmarking

In 2021, the utilities benchmarked with utilities around the world to improve its understanding of CC deployment and applications. A survey was sent to over 150 utilities around the globe. In total, 19 utilities participated in the benchmarking survey. The survey consisted of 24 questions that focused on CC usage, performance metrics, conductor applications, and system protection. While a limited number of utilities responded (compared to the outreach), the benchmarking survey provided helpful information on CC deployment and performance metrics. This information supported the utilities understanding of the benefits of CC including reliability and safety improvements and wildfire risk reduction. The utilities did not conduct additional benchmarking outside of this joint IOU effort in 2022. In 2023, the utilities will develop a new survey that accounts for results from the testing workstream, learnings from the M&I best practices and new technologies workstreams, and other information that becomes available. The utilities will deploy a new survey in Q3/Q4 2023. Based on the results of the survey and the collaboration and learnings from the other workstreams, the utilities will look to continue to benchmark over this WMP period.

11 Costs

11.1 Introduction

In the 2022 WMP Update filings, the utilities presented an initial capital cost per circuit mile comparison of installation of CC and described the types of costs incurred, cost accounting methods, and the factors that can drive CC costs higher or lower. The utilities demonstrated that based on each utilities' CC / system hardening program, costs are relatively comparable taking into account each utilities' resources, scope, and operational constraints. Since the 2022 WMP Update, the utilities have continued to meet and discuss CC unit costs and undergrounding unit costs. Below, the utilities provide an updated CC capital cost per circuit mile, initial undergrounding unit costs, and plans for 2023.

11.2 Updated Covered Conductor Capital Cost Per Circuit Mile

The utilities have prepared an updated capital cost per circuit mile comparison of the installation of CC. To construct this unit cost comparison, the utilities used the same six cost categories presented in the 2022 WMP Update filings including labor, material, contract, overhead, other, and financing.[6] These cost categories are intended to capture the total capital cost per circuit mile of CC installations. For purposes of this report, the utilities obtained recorded and/or estimated costs for construction that occurred during 2022. Table 18, below, shows the current CC capital unit cost per circuit mile comparison across the six utilities.

Table 18: IOU Comparison of Covered Conductor Capital Costs Per Circuit Mile

Cost Components	SCE		PG&E		SDG&E		Liberty		PacifiCorp		BVES	
	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%
Labor (Internal)	$ 9,000	1%	$ 130,000	16%	$ 321,000	22%	$ 117,000	10%	$ 18,000	2%	$ 18,000	2%
Materials	$ 132,000	19%	$ 151,000	18%	$ 84,000	6%	$ 73,000	6%	$ 218,000	28%	$ 360,000	49%
Contractor	$ 383,000	56%	$ 394,000	48%	$ 303,000	21%	$ 857,000	70%	$ 446,000	57%	$ 300,000	41%
Overhead (division, corporate, etc.)	$ 141,000	20%	$ 140,000	17%	$ 355,000	24%	$ 163,000	13%	$ 50,000	6%	$ 60,000	8%
Other	$ 14,000	2%	$ 3,000	0%	$ 317,000	22%		0%	$ 25,000	3%		0%
Financing Costs	$ 9,000	1%	$ 8,000	1%	$ 71,000	5%	$ 10,000	1%	$ 21,000	3%		0%
2022 Total	$ 688,000	100%	$ 826,000	100%	$1,451,000	100%	$ 1,220,000	100%	$ 777,000	100%	$ 738,000	100%

As illustrated in Table 18, the 2022 CC capital cost per circuit mile ranges from approximately $688 thousand to approximately $1.45 million. While not a true comparison, because the figures are in

[6] Labor represents internal utility resources, such as field crews, that charge directly to a project work order. Materials include conductor, poles, etc. that get installed as part of a project. Contract represents all contractors, such as field crews and planners, and consultants utilities use as part of their CC programs. Overhead represents costs, such as engineers, project managers and administrative and general, that get allocated to project work orders. Other represents costs such as land fees, permit fees and costs not assignable to the other categories. Financing represents allowance for funds used during construction (AFUDC) which is the estimated cost of debt and equity funds that finance utility plant construction and is accrued as a carrying charge to work orders.

nominal dollars, the 2022 unit cost range is similar to the 2021 unit cost range of approximately $565 thousand to approximately $1.5 million. As discussed in the 2022 WMP Update report, the capital cost per circuit mile for CC can vary due to multiple factors such as type of CC system and components installed, terrain, access limitations, permitting, environmental requirements and restrictions, construction method (e.g., helicopter use), amount of poles/equipment replaced, degree of site clearance and vegetation management needed, and economies of scale. Below, the utilities describe any changes to their cost make-up and the factors that contribute to the cost changes from 2021.

11.3 Initial Undergrounding Capital Cost Per Circuit Mile:

PG&E, SCE and SDG&E have prepared an initial capital cost per circuit mile comparison of the conversion of overhead conductor to underground. Liberty and BVES are not installing undergrounding as part of their wildfire mitigations. PacifiCorp has only installed one half of a mile so does not have sufficient recorded data to add; however, PacifiCorp is installing undergrounding projects over this WMP period and thus unit cost data will be assembled once more undergrounding is installed. Similar to the construction of the CC unit cost comparison, the utilities organized their capital costs (and/or estimates) into the same six cost categories. These cost categories are intended to capture the total capital cost per circuit mile of undergrounding. For purposes of this report, the utilities obtained recorded and/or estimated costs for construction that occurred during 2022. Table 19, below, shows the initial undergrounding capital unit cost per circuit mile comparison across the three large utilities.

Table 19: SCE, PG&E and SDG&E Comparison of Undergrounding Capital Costs Per Circuit Mile

Cost Components	SCE		PG&E		SDG&E	
	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%
Labor (Internal)	$ 25,000	1%	$ 231,000	9%	$ 45,000	2%
Materials	$ 417,000	19%	$ 271,000	11%	$ 165,000	7%
Contractor	$ 1,201,000	56%	$ 1,665,000	66%	$ 1,754,000	71%
Overhead (division, corporate, etc.)	$ 438,000	20%	$ 247,000	10%	$ 417,839	17%
Other	$ 35,000	2%	$ 63,000	3%	$ 14,654	1%
Financing Costs	$ 29,000	1%	$ 31,000	1%	$ 77,756	3%
Total	$ 2,145,000	100%	$ 2,508,000	100%	$ 2,474,739	100%

As illustrated in Table 19, the 2022 undergrounding capital cost per circuit mile ranges from approximately $2.03 million to approximately $2.51 million. The capital cost per circuit mile for undergrounding across the three utilities is remarkably consistent given that undergrounding costs typically have a much larger cost range than CC. Similar to CC, undergrounding costs vary due to multiple factors such as type of undergrounding system and conductor, terrain, access limitations, route changes, permitting, environmental requirements and restrictions, construction methods, and economies of scale. Below, SCE, SDG&E and PG&E describe the make-up of their undergrounding capital costs and the factors that contribute to the cost differences.

11.3.1 SCE

11.3.1.1 CC Unit Cost Make Up

The 2022 CC costs are based on work completed in 2022. Some projects completed in 2022 have incurred costs from prior years. SCE's unit cost is based on the average cost of nine different regions within SCE's service area. SCE's unit costs are typically presented as direct costs only (exclude corporate overheads and financing costs). For purposes of this report, SCE has added corporate overheads (to the overhead cost category) and financing costs to its direct unit cost for comparison with the other utilities. SCE continues to use two CC designs, a 17 kV and 35 kV CC with multiple ACSR and copper conductor sizes.

In 2022, SCE did make a change to its WCCP construction standard by adding the replacement of open wire secondary or weather-resistant aluminum (OWS or WAL) with multiplex secondary conductors; however, this change is not anticipated to show up in the unit costs until 2024. No CC projects completed in 2022 included replacement of secondaries. SCE estimates, on average, replacing secondaries will cost approximately $60 thousand per circuit mile.

11.3.1.2 CC 2022 Cost Changes:

Using the nominal amounts of the 2021 and 2022 unit costs, SCE experienced an approximate 16% increase. The primary drivers of this increase include a combination of a larger percentage of work in the Rural region, e.g., the Arrowhead District, and contractor rate increases. Work in higher elevations in rugged areas tend to take longer, increasing contract labor costs. This increase coupled with higher contractor rates were the main cost drivers. Additionally, SCE experienced material and supply price increases. Also, in 2022, SCE began to use SCE labor in some regions.

11.3.1.3 Undergrounding Cost Make up

The 2022 undergrounding costs are based on work completed in 2022. Projects completed in 2022 have incurred costs from prior years. SCE's unit cost is based on approximately 14 miles of undergrounding. The 14 miles of undergrounding had a low level of difficulty and did not include secondaries or services.

A low difficulty level means the terrain was relatively flat, there was less civil construction due to existing infrastructure, and there were none to minimal re-routing required. SCE anticipates higher costs in future unit cost assessments because the projects will have a mix of low to high difficulty.

11.3.1.4 Undergrounding Cost Drivers

For undergrounding projects, SCE leverages its Integrated Wildfire Mitigation Strategy consequence model, which defines the most severe locations in SCE's HFRA. These are locations that meet one or more of the following characteristics: 1) egress constrained, 2) burn-in buffer, 3) 10,000+ acres burned at 8 hours, 4) extreme high wind areas, and 5) communities of elevated fire concern. The costs to underground in these areas can vary significantly. Below, SCE describes several cost drivers that could lead to increased costs.

Construction – in various types of terrain, geography, topography, and population density. Different levels of difficulty in construction can significantly impact the costs. For example, a low difficulty level project that includes straight/minimal bends and minimal re-routing will likely be a lower cost compared to a high difficulty level project, which can have rocky, hilly terrain requiring significant re-routing. Additionally, any unanticipated changes in design after release can impact costs. For example, sometimes, during construction, a trench is not able to be constructed due to other infrastructure already there (an outcome of outdated basemaps). In this type of circumstance, the planning department would re-design the route including seeking agency feedback which would take additional time to complete and impact schedule and costs.

Permitting and environmental clearances – acquiring permits, resolving land rights and agency requirements, and curing cultural discoveries can be a lengthy process. The number of permits, the types of permits, the amount of land right issues that need to be resolved, and the types of cultural discoveries can increase the costs of a project.

Labor type and resource availability – Both civil crews and QEW electrical crews are required and using internal SCE labor versus contract labor may impact costs.

Additionally, delays can occur due to weather (e.g., rain/snow, RFW days, etc.), supply chain constraints, permit requirements, and environmental constraints (e.g., nesting birds), which can also increase costs.

11.3.2 PG&E

11.3.2.1 CC Unit Cost Make Up

PG&E's unit cost analysis is based on completed projects. Projects are defined by circuit and span. Costs are recorded using SAP software. Of the 335 miles used to analyze the unit cost, these were projects that were marked completed in 2022. Some of the mileage may have been constructed in previous years. Five of the miles were fire rebuild, which typically have a lower unit cost. 329 miles completed were regular system hardening work and one mile was classified as other.

Costs were organized per the six main categories agreed upon with the other utilities. 200 miles were constructed using external crews, categorized as Contract and 135 miles were constructed using Internal labor, categorized as Labor.

PG&E's Overhead Hardening (CC Installation) scope achieves risk reduction through these foundational elements: bare primary and secondary conductor replacement with covered equivalent, pole replacements, non-exempt equipment replacement, overhead distribution line transformer replacement, framing (composite crossarms and insulators) and animal protection, and vegetation clearing.

11.3.2.2 CC Cost Drivers:

PG&E's CC installation costs are driven by these key contributors:

1. Pole replacement – nearly 100% of the poles require replacement due to the additional weight/sag of the new CC.
2. PG&E incorporates numerous initiatives into a single hardening project. Non-exempt equipment and ignition component replacement impacts the cost by including the material and labor installation cost of the new equipment where it requires replacement.
3. Vegetation clearing in support of the new overhead line can be a significant cost added to these projects. Both the increased height of the poles, the widened cross-arms, and the increased sag

of the line can vary the cost considerably. This cost alone can add between $50k to $400k per mile depending on the terrain and the location of the line. The rural nature of much of the high-risk HFTD infrastructure drives this need.

11.3.2.3 CC Cost and Impact Driver changes for 2022

For PG&E, unit costs have steadily decreased for the Overhead System Hardening program, that includes CC, into 2022. Major cost drivers include a decreased volume of vegetation impacts on overhead hardened lines and unit cost RFPs (request for proposals) to stabilize contract pricing.

It is likely that these unit costs have mostly leveled off and will only increase due to inflation and economic pressures as this program continues.

Continued costs for PG&E are labor costs, both internal and external (contractor) costs.

For impact drivers to CCs, PG&E is continuing to utilize a combination of undergrounding and microgrids as the primary system hardening effort to reduce wildfire risks. Where these efforts are less feasible, PG&E may use CC as a wildfire mitigation tool for Overhead System Hardening. As PG&E continues undergrounding efforts and finds additional areas that are prohibitive to the undergrounding program, PG&E may increase CC use for those specific areas.

11.3.2.4 Undergrounding Cost Make up

PG&E's unit cost analysis is based on completed projects with costs recorded in our SAP software. Of the 76 miles used to analyze the unit cost, these were projects that were marked completed in 2022. Some of the mileage may have been constructed in previous years, 46 of the miles were fire rebuild, which typically have a lower unit cost, and 30 miles completed were regular system hardening work.

Costs were organized per the six main categories agreed upon with the other utilities, 53 miles were constructed using external crews, categorized as Contract, and 23 miles were constructed using internal labor, categorized as Labor.

11.3.2.5 Undergrounding Cost Drivers:

In executing the System Hardening program, PG&E first uses a scoping criterion that identifies the highest risk areas, and then selects the appropriate risk mitigation approach for that circuit which may include undergrounding, remote grid installation, line removal, or overhead hardening (depending on the local circumstances). Since late 2021, PG&E has prioritized undergrounding as the preferred approach to reduce the most system risk. Once a circuit is selected for undergrounding, PG&E evaluates each proposed circuit segment quantitatively and qualitatively to mitigate the maximum amount of risk and evaluate feasibility and executability. Potential cost drivers can include:

- Existing infrastructure (e.g., water, natural gas, and sewer/stormwater drainage systems, bridges, streetlights, SCADA communications, number of services and transformers, community traffic and access impacts)
- Major execution dependencies (e.g., land rights, environmental permitting, requirements for future road widening, paving plans, or moratoriums by local governments)
- Land and environment considerations (e.g., accessibility for ingress and egress of areas, waterway crossings, sensitive species habitats, land rights and easements, tribal lands, steep gradient, hard rock, tree density)

- Community and Customer Considerations (e.g., cultural considerations, community, and customer impact)

Any of the above considerations may create delays or complexities that can impact the scope, cost, and schedule of undergrounding projects.

Furthermore, undergrounding projects are executed in multiple stages once the circuit segment has been identified based on the criterion described above for undergrounding:

1. Scoping: Identifying the proposed route of undergrounding the electric distribution lines, including gathering base map data (e.g., LiDAR and survey data of the expected route) and identifying any long lead time dependencies (e.g., land acquisitions, environmental sensitivities and permits). Scoping includes breaking out planned circuit segments into smaller, more manageable projects. Scoping is the first step necessary to provide visibility to the construction feasibility and possible execution timing.
2. Designing/Estimating: Designing the specific project to determine trench location, connection points, equipment details, materials needed, and all related details, such as circuitry and pull boxes. This design also provides specifics for the land rights needed and the drawings that are submitted for permits. The total project cost, including expected labor and materials, is calculated at this stage.
3. Dependencies: During this stage we may need to obtain land rights, environmental permits, construction contracts, encroachment permits from local counties, order long-lead materials, finalize construction cost estimates, and determine the construction schedule. The two longest lead dependencies often include obtaining 1) land rights and 2) environmental permits.
4. Construction: Executing the undergrounding takes place in two phases: 1) civil construction and 2) electric construction. Project schedules may be significantly impacted during civil construction for some of the following reasons: unanticipated weather, discovery of hard rock, and detection of unmarked existing utility infrastructure. Once civil construction is complete with conduit and boxes installed, then electric construction resources pull the cable through the conduit, splices segments together and re-connects the customers to the new underground system. Customer input to the timing of re-connection, material availability, weather and other risks can impact the electric construction schedule, as well.

As projects move through each stage, schedule certainty improves. Project schedules can change at any time from project dependencies, which may cause specific projects to move across years. Generally, if a project is not completed during the year that it was originally targeted for completion, it will continue through all the job phases and be completed in a subsequent year.

PG&E works closely with customers, governments, agencies, tribes, and regulatory officials to manage these issues within the program to minimize delays and optimize the efficiency of projects wherever possible.

11.3.3 SDG&E

11.3.3.1 CC Cost Make Up

Each project goes through a six-stage gate process as follows:

Stage 1 – Project Initiation (duration ~1-3 months)
Stage 2 – Preliminary Engineering & Design (duration ~6-9 months)
Stage 3 – Final Design (duration ~3-5 months)
Stage 4 – Pre-Construction (duration ~1-2 months)
Stage 5 – Construction (duration ~3-4 months)
Stage 6 – Close Out (duration ~6-12 months)

The total duration of a project has an estimated duration of approximately 20 to 35 months.

SDG&E's CC per mile unit capital costs is made up of the following six major cost categories:

1. Labor (internal) – directs costs associated with SDG&E full-time employees (FTE), including but not limited to individuals from project management, engineering, permitting, environmental, and land management departments.
2. Materials – estimated costs of material used for construction including steel poles, wire, transformers, capacitors, regulators, switches, fuses, crossarms, insulators, guy wire, anchors, hardware (nuts, bolts, and washers), signage, conduit, cable, secondary wire, ground rods, and connectors.
3. Contractor – estimated costs for construction-related services, including civil construction contractors for pole hole digging, anchor digging and substructures, and street/sidewalk repair; electrical construction for pole setting, wire stringing, electric equipment installation and removals; vegetation management where required including tree trimming or removal, and vegetation removal for poles and access paths; environmental support services including biological and cultural monitoring; traffic control; and helicopter support for pole setting, wire stringing, and removals. SDG&E's contractor costs is an estimated average for both internal and contracted electric construction activities, where contract crews are estimated to account for approximately 50% of the construction costs typically completed in a year starting in 2023 versus the 75% that was in the previous estimate.
4. Overheads – estimated costs associated with contracted services not related to construction including engineering, design, project management, scheduling, reporting, document management, GIS services, material management, constructability reviews by Qualified Electrical Worker (QEW), staging yard leases/setup/teardown/maintenance, and permitting support throughout the entire lifecycle of a project, as well as services related to program management including long term planning and risk assessment.
5. Other – estimated costs associated with indirect capital costs. These costs are estimated to be approximately 22% of direct capital costs that accumulate on a construction work order. This includes administrative pool accounts that are not directly charged to a specific project, including internal labor vacation, sick, legal, and other expenses.
6. Financing Costs – estimated costs associated with the collection of AFUDC when a construction work order remains active. Most SDG&E jobs are active for approximately 6 to 10 months from the time the job is issued to construction until it is fully completed and the collection of AFUDC charges stop.

11.3.3.2 CC Cost Drivers Update

Costs can vary significantly from project to project for a variety of reasons, including engineering and design, land rights, environmental, permitting, materials, and construction. Below is a description of these factors and why the costs can vary from project-to-project.

Engineering & Design

SDG&E collects LiDAR (Light Imaging Data and Ranging) survey data before the start of design and again after construction is completed. During the LiDAR data capture, other data including photos (i.e., ortho-rectified images of the poles and surrounding area, and oblique pole photos), and weather data is acquired. After collection of the raw LiDAR and Imagery data, it is processed to SDG&E's specification and includes feature coding and thinning of the LiDAR data, and selection and processing of the imagery data. The entire process for delivery to SDG&E's specification can take weeks to months depending on the size of the data capture. This LiDAR data capture is used to support the base-mapping, engineering, and design processes (Stage 1 and Stage 6).

Currently, the engineering and design of all CC projects are conducted by engineering and design consultants, and their deliverables are reviewed by a separate Owner's Engineering (OE) consultant to ensure compliance with SDG&E standards and guidelines. At this time, SDG&E does not have the resources to conduct the engineering and design required at this scale of work; however, there are assigned SDG&E full time engineering staff that provide oversight of all engineering and design consultants, including the OE. The engineering component of work relates to the structural analysis, including Power Line Systems – Computer Aided Drafting and Design (PLS-CADD) modeling, foundation calculations, or geotechnical studies. The design component includes the drafting, entering design units into SAP for material ordering and costing system, and building the job packages that are sent to construction. In some cases, one consultant can perform both the engineering and design function, and in others cases an engineering consultant collaborates with a design consultant. In all cases, SDG&E's Owner's Engineer will perform both engineering and design review support. Costs from consultants can vary depending on the size and complexity of the project, and due to various other factors including environmental constraints, land constraints, permitting requirements, or scoping changes that can occur from the start of design and throughout construction. The design stage (i.e., start of design to issuance of job package to construction) typically takes anywhere from six months to two years depending on the size and complexity of the project and the challenges with acquisition of land rights, environmental release, and/or permits. In some cases, our environmental releases cannot be released until we receive the permit from the agency as they may require additional environmental measure to be placed on the work and will need to be outlined in the environmental release.

SDG&E requires every pole be engineered using PLS-CADD software during the design phase and the post-construction phase. This software allows SDG&E to leverage LiDAR survey data (pre- and post-construction) and AutoCAD drawings, and to design the poles, wire, and anchors to meet General Order (GO) 95 Loading (Light and Heavy Loading) and Clearance Requirements, as well as to meet Known Local Wind requirements (e.g., 85 mph and in some cases 111 mph wind). SDG&E also requires its engineering and design contractors who use PLS-CADD software to have a California-registered Professional Engineer review and approve the final PLS-CADD model.

Land and Environmental

SDG&E requires all projects to go through a land and environmental review process at each stage of the design process. These processes are predominantly supported with the help of land management and environmental service consultants but are overseen by SDG&E representatives in each respective department. The land process includes research of our land rights, interpretation, and may include support obtaining the proper land rights when required. Through the land rights design review process, SDG&E determines the land ownership of facilities (e.g., poles and wire) to determine if the scope of work is will stay within existing land rights or if new/amendment land rights would be necessary. These results are shared with the engineering, design, and environmental teams. Once the land rights are determined, environmental performs an assessment, determines the environmental impacts if any, and provides input to the design process to minimize and/or avoid environmental impacts. These land and environmental reviews can drive changes to the design and add time and cost to the project. For example, in many cases, SDG&E does not have the land rights to build the overhead CC design within its existing easement, or in some cases it only has prescriptive rights. In those cases, SDG&E has to amend or acquire the proper land rights, or redesign the project, if possible, to stay within the land and/or environmental constraints. If acquiring or amending land rights is required, this can take weeks to months depending on the property owner (e.g., private, BIA, State, Federal, or Municipality) and the level of change to the existing conditions.

Materials

SDG&E's philosophy with CC, like SCE, is to install it in an open-crossarm configuration. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at the structure. Where connections are necessary, insulation piercing connectors (IPCs) are used to avoid stripping the wire and causing damage to the conductor and negating the need to wrap the connection with insulating tape. SDG&E also requires the use of vibration dampers, where necessary, to mitigate conductor damage due to Aeolian vibration. SDG&E replaces most wood poles to steel, and in some cases replaces existing steel poles if they are not adequate to support the new wire (e.g., inadequate clearance and/or mechanical loading capacity). In many cases equipment is replaced during these reconductor projects if it is older, is showing signs of failure, and/or needs to be brought up to current standards. The reason to replace wood poles with steel is due to several reasons, including the fact steel is more resilient to fires than wood and is seen as a defensive measure, steel is a man-made material and the strength and dimensions are consistent and have much smaller tolerances than wood, and because many of SDG&E's wood poles are over 50 years old. In some cases, SDG&E may also need to relocate the pole line to an area where it is more accessible to build and maintain but will require obtaining a new easement. SDG&E also replaces wood crossarms with fiberglass crossarms, insulators with polymer insulators, and replaces switches and regulators as necessary. For transformers, SDG&E developed specific criteria for replacement. A transformer will be replaced if it is internally-fused regardless of age, if it's greater than 7 years old, if it has visual defects or damage (leaks, burns, corrosion, etc.), is less than 25 kVA, or if the transformer does not pass volt-drop-flicker calculation. SDG&E also replaces secondary wire that is either open (non-insulated) or "grey wire" (covered secondary wire where the insulation is grey in color). On most projects, there is a smaller underground job associated with the overhead work. This typically occurs when a pole feeds underground (aka a Cable or Riser Pole) and the new pole location may be too far from the existing position such that the existing cable, conduit, and terminations may not reach the new pole position. In these cases, a small underground job will be initiated to have the crews intercept the run of underground conduit, install a new handhole, install a new run of conduit and cable to the new pole location, and splice the cable in the new handhole to make the connection to the existing underground system.

In 2021 and 2022, SDG&E experienced material supply chain issues, with CC materials as well as materials common to bare and CC. These supply chain issues were the result of various factors including impacts from COVID-19. In the case of CC, SDG&E currently sources the conductor from multiple suppliers; however, the associated materials such as piercing connectors and clamp dead-ends come from one supplier out of Europe and experienced significant delivery delays due to COVID-19 and issues with US Customs paperwork in 2021. In 2022 SDG&E had material delays with secondary conductor, 10 ft fiberglass guy strain insulators, transformers, guy grips, and fiberglass crossarms. SDG&E also experienced delays receiving other material due to COVID-19 supply chain disruptions and competition for the same materials used by other utilities including transformers and other materials common to various utilities across the country. Material delays can cause construction delays or cause construction to work less efficiently, thus impacting project schedules and costs. To mitigate material delays SDG&E's engineering and design team, as well as suppliers, work together to provide long term forecasting and ensures materials are ordered with enough lead time to receive the materials in time for construction, and when necessary, substituting material.

Construction

One of the most significant variables, and most difficult to predict, is the civil portion of construction. The civil portion of a project includes the pole hole, anchor, and handhole digging and can vary significantly depending on several factors including accessibility (truck accessible versus non-truck accessible), soil conditions (rock versus soft soil), methods of digging (hand tools versus machine), and environmental constraints that may limit the method of digging or access protocols. For example, a 0.7 miles project completed a couple of years ago was on the side of a steep mountain side and all the material, equipment (pneumatic drill and hand tools), and crews had to be flown in and out every day for months. The civil crews encountered significant rock at most locations and the spoils from the digging had to be flown out due via helicopter to environmental concerns rather than spreading the spoils on location. Each pole and anchor were back-filled with concrete using helicopters because of the slope of the mountain and due to the significant mechanical loading due to winter storms (wind and ice loading). In contrast to this mountain side project example, SDG&E has had other projects that are truck accessible, that do not require concrete backfill and allow the spoils to be spread out on location.

Another reason costs can vary significantly from project to project is due to the time of year and location. SDG&E often deals with elevated fire weather conditions which requires a dedicated fire watch crew to be present at each location where there is work happening that can pose a fire risk. In some cases, SDG&E has multiple dedicated fire watch crews on a project as there may be multiple civil and electric crews working at different locations at the same time on the same project. Some locations are also so remote that the drive time from the staging yard to the site can take a significant amount of time out of each workday that the crew may work longer hours and/or over the weekend, including Sundays, thus increasing overtime hours for the construction crew and all other support services (e.g., traffic control, environmental monitors, etc.). In some cases, generators are used due to the remote nature of some customers and the lack of ties with other circuits in SDG&E's service area. Generators require special protection schemes, equipment, and resources to adequately plan, deploy, setup, monitor, and tear-down which increase the installation costs.

Lastly, construction costs can vary depending on the crew building the project and issues encountered during construction that were not anticipated during design. SDG&E currently uses four primary construction contractors who perform the electrical construction and typically sub-contract the civil work (e.g., pole hole, anchor, handhole digging), helicopter, traffic control and dedicated fire watch. SDG&E also uses internal electric construction teams who typically contract out the helicopter, traffic control, dedicated fire watch and civil work (pole hole and anchor digging). Based on SDG&E's experience with its traditional hardening program, in 2023 it is estimated that 50% of the construction work costs will be performed by contractors and 50% by internal crews. The costs between external and internal crews can vary depending on the work scope, location (rural versus very rural), methods of construction (e.g., truck accessible versus non-truck accessible), time of year (e.g., fire season and non-fire season, and wet versus dry conditions), and issues encountered during construction. Larger projects (typically 20 or more poles) that are not assigned to an internal crew are sent out to bid with the three prime electrical construction contractors and are often bundled with other projects on the same circuit to gain economies of scale. SDG&E has determined that its ideal bid size is 100-200 poles; however, some bids have been significantly greater and some can be much smaller. The size of bids can change significantly depending on the location of a project, time of year, and schedule of the project. SDG&E has seen changes with pricing due to competition for construction resources with the other utilities in the state and this can drive-up costs depending on the volume of work and timing with other projects statewide.

11.3.4 PacifiCorp

11.3.4.1 CC Unit Cost Make Up

For purposes of this comparison, PacifiCorp has again aligned its costs into the six major categories. No changes were made in 2022 related to how costs are organized into the six main categories. PacifiCorp is basing the cost per mile on ten projects totaling about 33 miles of primarily spacer cable. These projects were placed in service during 2022; however, design, material procurement, permitting, and some construction may have taken place prior to 2022.

11.3.4.2 CC Cost Drivers

PacifiCorp has identified eight main cost drivers for the installation of CC. The cost drivers are discussed below in terms of cost increases that have been experienced, highlighting how impactful these components can be on the overall project cost.

Access

PacifiCorp includes costs for required access to facilitate project construction in projects charged to the work order. These costs may include vegetation clearing, road construction, or other site preparation activities. These costs will typically be included in the contractor total for purposes of this cost analysis as this work is predominantly contracted. Additionally, these costs can also range significantly between projects based on the specific location and terrain where work is conducted. Projects that include significant off-road scopes tended to be most impacted, though this is somewhat offset by limited flagging costs.

Pole Replacement:

PacifiCorp evaluates all poles for strength and clearance using PLS CADD on spacer cable projects. Poles are then selected for replacement for the following reasons: insufficient strength to accommodate CC, insufficient minimum clearance, relocation is required, or not constructible in the current state. Projects completed in 2022 averaged 25 poles per mile due to projects with larger conductor sizes, short spans on in-town projects, and two projects designed for double circuits. Additionally, nearly all poles identified are replaced with non-wood fire resistant materials (predominantly fiberglass) at a greater cost than like-for-like replacement with wood.

Construction Labor

In 2022, PacifiCorp continued to receive higher bid prices. Contractors reported needing to include incentives to attract adequate labor to complete projects. Increases in construction labor costs were the single largest driver in project cost increases. As of January 31, 2023, PacifiCorp has awarded approximately one third of the 2023 planned construction work scope and is forecasting that these higher costs will continue.

Post Construction Inspections

In 2022, it was recognized that the total amount of construction exceeded the capacity of internal staff to adequately inspect as the construction was taking place. Based on this, external construction inspectors have been hired to monitor construction, while it is taking place, and complete a formal inspection of each line segment as it is placed into service. While this comes at a higher cost per line mile, it assures that the completed project matches the design. This will be on ongoing addition to project costs.

Permitting

As included in the company's 2021 Change Order, significant cost increases have been experienced for locations requiring access into seasonal wetlands and transmission under build projects. Future projects include environmentally sensitive areas that have been in NEPA or CEQA review with high environmental review costs. Additionally, projects scheduled for completion in 2023 have required cultural monitors for all ground disturbing activities and several re-designs to accommodate changes in current infrastructure layout requested by permitting agencies.

Materials

PacifiCorp experienced material cost increases on most commodity materials in 2022; however, this impact was limited for the group of projects in this analysis as much of the material was on order prior to 2022. Projects scheduled for completion in 2023 are expecting to experience more impact from these cost increases.

Internal Labor and Overhead

Internal labor increased on a per mile basis while overhead costs decreased. This is largely driven by a shift in staff charging directly to projects they are working on rather than an overhead account. These should be viewed largely as offsetting cost shifts.

Design Type

In 2022, PacifiCorp rebuilt approximately 7 miles of overhead distribution lines with CC. While there are many factors impacting the projects overall costs, a cursory review indicates a lower cost per mile as compared to spacer cable, generally attributed to the lower cost of materials, shortened project timeline, and reduction in engineering and design requirements. However, some of these costs are offset by the increase in pole replacements required with using a more standardized product. Based on this one project, PacifiCorp expects that CC could be a cost-effective option in many locations but requires more experience to understand the cost variability.

Based on the cost drivers discussed above, PacifiCorp anticipates higher costs for projects in 2023 and beyond.

11.3.5 BVES

11.3.5.1 CC Unit Cost Make Up

BVES continues to contract out most of the work with an internal Field Inspector overseeing the whole project. The design consists of our contractor performing field visits, wind loading calculations, developing the design and assembling the material lists. BVES purchases the materials and its contractor does the construction. The overhead costs consist of BVES internal groups. The capital cost per circuit mile are based on a double circuits' area in 2022.

11.3.5.2 CC Cost Drivers

CC unit costs decreased in 2022 compared to 2021. A higher percentage of poles were installed which support both 34.4 kV and 4 kV CC lines. These double circuit lines reduce installation and material costs. In addition, the construction crews have gained more experience installing CC and are more efficient.

11.3.6 Liberty

11.3.6.1 CC Unit Cost Make Up

Liberty's CC program is still relatively new and limited in scope compared to the large utilities. Liberty first piloted CC projects in 2020 in select areas that already needed line upgrades because of asset age and condition, and later focused on projects that targeted short line segments in HFTD areas, had reliability issues, and were in remote areas. An average of recent CC projects amounted to less than one circuit mile per project and only a total of 20 miles of CC were installed over the last 3 years. Liberty's CC work is substantially less than, for example, SCE's approximate 1,000+ miles of CC installed each year. Liberty's CC unit costs vary depending on terrain, number of poles replaced, type of conductor installed, project design and permitting requirements, and amount of vegetation management work required for the job order. Liberty used the same cost categories as described in the 2022 WMP Update report and did not make any major changes to its CC program.

11.3.6.2 CC Cost Drivers

Liberty's project life cycle ranges from 18-36 months depending on project scope and permitting complexity. There are many factors that may impact the total project life cycle and costs, including permitting and environmental requirements, easements, geography and terrain, and construction resource availability. Contractor costs for construction in its service area are a major cost driver for

Liberty. Projects typically take longer to construct because of the mountainous terrain and require more costly construction methods like helicopter use and hand digging. Other cost factors include permitting, weather, and environmental restrictions that limit scheduling flexibility and reduce productivity, causing construction costs to increase.

Conductor Type

Liberty has two CC designs that vary depending on project site access and terrain. These include 14.4 kV delta Aerial Spacer Cable (ACS or spacer cable) and CC solutions at this voltage level. In addition, because some of Liberty's service area includes 12.5 kV grounded Wye system, Liberty has piloted the use of CC. Liberty selects the two different system options based on the installation and maintenance of the two solutions.

The ACS solution has two or three covered conductors supported by a steel messenger. The framing for ACS includes brackets that hold the messenger under tension and for the current carrying conductors at full sag or zero tension. Installing and maintaining spacers requires a bucket truck; however, if accessibility is an issue, crews may require a bosun's chair to access the line adding to the costs.

The covered conductor solution includes various sizes of covered wire such as a 1/0, 2/0, or 397 kcmil AAC. The ACS solution projects have installed 1/0 AA wire with 1-052 AWA messenger and 1/0 AAC with 6AW messenger. Covered conductor is installed with framing similar to bare conductor wire in an open-crossarm configuration for framing and installation. CC is the preferred solution in areas with limited bucket truck access. Conductors are sized based on circuit load for both solutions. Wind and ice loading are major concerns in the Liberty service area and do not utilize conductors smaller than 1/0.

Location

A vast majority of Liberty's service area is in HFTD Tier 2 and Tier 3. In the initial phases of its covered conductor program, Liberty selected areas of its service area based on local knowledge of the wildland/urban interface, locations of high fire threat districts, remoteness of overhead lines, and the age and condition of the infrastructure. Areas were also chosen based on their accessibility and egress options during an emergency. Most of Liberty's covered conductor projects are in Tier 2 and Tier 3 at elevations between 6,200 to 7,500 feet over rugged, rocky terrain with limited seasonal access. Projects typically utilize helicopter pole sets, and crews are tasked with digging pole holes with pneumatic tools by hand versus trucks with augers. Pole holes take days versus hours to excavate, increasing labor hours and costs.

Pole and Asset Replacements

Most of the covered conductor projects Liberty has designed and constructed have required a significant number of pole replacements per circuit mile. When replacing existing poles, Liberty uses taller and larger class poles. This is due to new loads and increased weights of the covered conductor, as well as the age of existing infrastructure. Projects include installation of poles, insulators, crossarms, anchors (rock anchors), down guys, transformers, and switches.

Economies of Scale

Liberty has limited contract resources available during its construction period compared to the larger IOUs that have replaced thousands of circuit miles with CC. Liberty's contract costs are higher on a per mile basis than those of large IOUs, given Liberty's ratio of miles installed as compared to IOUs with significantly more miles installed. This factor has likely contributed to Liberty's higher CC cost per circuit mile.

Construction

Liberty's primary construction window is May 1 to October 15 due to weather and Tahoe Regional Planning Agency (TRPA) dig season restrictions. The construction window also coincides with seasonal tourism, a high number of RFW days, and during the typical fire season that further limits construction efforts and effects costs. These restrictions also constrain resources and add a premium on labor during construction season.

Vegetation Management

Liberty's service area is in a high elevation and mountainous terrain that is densely forested, averaging over one hundred trees per mile within maintenance distance of the conductor, given recent LiDAR data. Vegetation management inspectors and tree crews often need to access work sites on foot while carrying tools and equipment, resulting in much higher labor costs compared to typical work areas. In addition, due to the robust tree canopy in the Tahoe region, tree crew cost per circuit mile of construction has increased significantly due to SB 247 labor rate increases. Tree removals and pruning costs are unique to Liberty's service area and will increase the overall CC project costs.

In 2022, Liberty experienced an approximate 20% decrease in CC costs compared to 2021. This cost decrease was mainly due to Liberty's use of internal construction crews instead of contractors in 2021. Additionally, 2022 projects required fewer helicopter pole sets and less hand-digging than 2021 projects.

11.4 Next Steps

In 2023, the utilities will continue this workstream and further discuss and document CC recorded/estimated unit costs, undergrounding unit costs and cost drivers as well as assess adding initial unit costs for other alternatives. The utilities will also document any lessons learned.

12 Lessons Learned

12.1 Introduction

In the utilities' 2022 WMP Update decisions, Energy Safety identified an ACI for all utilities to provide goals and timelines for implementing lessons learned from the CC joint effectiveness study. Specifically, Energy Safety ordered all utilities to:

- Provide a concrete list of goals with planned dates of implementation for any lessons learned in the CC effectiveness joint study.
- Provide a table indicating which WMP sections include changes (compared to its 2021 and 2022 Updates) as a result of the CC effectiveness joint study. This should include, but not be limited to:
    - Changes made to CC effectiveness calculations.

- Changes made to initiative selection based on effectiveness and benchmarking across alternatives.
- Inclusion of REFCL, OPD, EFD, and DFA as alternatives, including for PSPS considerations.
- Changes made to cost impacts and drivers.
- An update on data sharing across utilities on measured effectiveness of CC in-field and pilot results, including collective evaluation.

As described in the sections above, the utilities are sharing and documenting information and lessons learned, and are driving to understand if best practices, common methods, and greater comparability can be established. Where utilities have made improvements based on this working group, they are described in the sections above. Importantly, consistent with the 2022 WMP Update filings, while not an objective of the working group, the utilities anticipated that there could be lessons to learn from one another such as construction methods, engineering/planning, execution tactics, etc. that could help improve each utilities' deployment of CC. Since the final decisions on the utilities' 2022 WMP Update filings and as part of each workstream meeting, the utilities have discussed whether or not there are lessons learned and if so, documented these and any plans the utilities have to implement those lessons. In the limited time the utilities have had in 2022 to meet this requirement, we have documented a few lessons learned; however, it is important to note that each utilities' CC program (the initial focus of this effort) had been previously established and was based on past benchmarking, research, testing, and lessons learned from other utilities including SCE (see, e.g. the Covered Conductor Compendium), i.e., many lessons learned were already incorporated into each utilities' CC program. Notwithstanding this, and considering the expansion of this working group, the utilities are committed to documenting lessons learned and plans to implement them.

12.2 Lessons Learned

The utilities agree that it is helpful to share information, practices, and data across the utilities as this can lead to improvements in reducing wildfire risk, safety incidents, and the impacts of PSPS, and improvements with other utility objectives. In furtherance of this objective, and given that a simple table cannot provide the information in a readable format with the ACI requirements, the utilities describe their lessons learned for this working group by the required subject areas.

12.2.1 CC Effectiveness Values

Pursuant to the testing results and further analysis, SCE and PG&E modified their estimated effectiveness values for certain risk drivers since its 2022 WMP Update submissions and have implemented these changes. SDG&E refreshed its effectiveness analysis per previous methodology but have not yet incorporated the updated value in its decision making. SDG&E anticipates completing this by December 2023. Based on the other utilities' previous estimates, the testing results, and their own data, no changes to CC effectiveness values were warranted at this time. These changes are described above in the Estimated Effectiveness workstream. The changes to effectiveness values have and are being incorporated into RSE calculations which in turn will feed into the utilities' decision-making processes. These updated RSE calculations will also be incorporated into utilities' future filings such as RAMP, GRC, and as applicable the WMP. If additional changes are made to effectiveness values, the utilities will document those lessons learned.

12.2.2 Data Sharing

An update on data sharing across utilities on measured effectiveness of CC in-field and pilot results, including collective evaluation. The utilities have and continue to share information across all workstreams. During 2022, utilities provided updates on recorded effectiveness. These included presentations and overviews on data, dashboards, and areas of continued improvement. The utilities also discussed their CC efforts including any pilots and shared these experiences.

12.2.3 Inclusion of REFCL, OPD, EFD, and DFA as alternatives, including for PSPS considerations

As described in the New Technologies section of this report, the utilities will discuss and document data and methods that can be used to estimate the effectiveness of these technologies. This workstream is new and the utilities have identified a series of workshops to develop this workstream. To date, the utilities have not documented any lessons learned or changes from 2021 or 2022 for inclusion of new technologies.

12.2.4 Cost Impacts and Drivers

As described in the Cost section of this report, the utilities have provided an updated CC capital cost per circuit mile and document the cost changes and drivers. As explained in last year's report, each CC project is unique and will have different costs. Additionally, there are many factors that can increase costs including, for example, economies of scale, the mix of work across regions and differing terrain, contractor rates, permitting, resource constraints, and environmental restrictions. In 2022, the utilities provided updates with one another on these costs through presentations and overviews including trends, material price changes, and other cost-related information. Please see the Cost section in this report for further details the changes in cost impacts and drivers from last year's report.

12.2.5 Changes made to initiative selection based on effectiveness and benchmarking across alternatives.

The utilities have not made changes to initiative selection based on this joint IOU effort. The data and information compiled has confirmed the utilities understanding that CC is effective at reducing wildfire risk and highly effective at reducing most contact from object and wire-to-wire risk drivers. The testing has also shown CC is effective at reducing other risk drivers as well. Should one or more utilities make changes to initiative selection as a result of this effort, we will document those lessons learned as well as plans to implement them.

12.3 Next Steps

In 2023, the utilities will document all lessons learned across all workstreams and will develop plans to implement those lessons learned, as applicable.

13 Conclusion

This joint IOU report provides descriptions of the progress the utilities have made to better understand the long-term effectiveness of CC and its ability to reduce wildfire risk and PSPS impacts (and, in comparison to alternatives) as well as CC M&I practices, new technologies, and lessons learned. The utilities have made progress on this effort and describe plans for 2023 to conduct a large number of workshops to further understand the data and analyses that have been compiled, identify best practices for CC M&I, assess new technology effectiveness and the sharing of practice and implementation strategies, and discuss methodologies that can be employed across all utilities to improve comparability. The utilities look forward to continuing these efforts in 2023 and providing future updates.

Appendix A: Effectiveness and Implementation Considerations of Covered Conductors: Testing and Analysis