BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Docket #2023-UPs ElectricalUndergroundingPlans@energysafety.ca.gov

MUSSEY GRADE ROAD ALLIANCE COMMENTS

ON THE DRAFT GUIDELINES FOR THE 10-YEAR ELECTRICAL

UNDERGROUNDING DISTRIBUTION INFRASTRUCTURE PLAN

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INTRODUCTION

The following comments have been prepared for Mussey Grade Road Alliance (MGRA or Alliance) regarding stakeholder comments on the Development of Guidelines for 10-Year Electrical Undergrounding Distribution Infrastructure Plan.[1] As per the cover letter posted to the docket on May 8, 2024 by Program Manager Kristin Ralff Douglas May 29, 2024 is the due date for comments and June 10, 2024 the due date for reply comments.[2]

BACKGROUND

MGRA generally supports the Draft 10-Year Electrical Undergrounding Plan Guidelines. While we have fundamental issues with the whole prospect of making undergrounding a preferred mitigation, we find that Energy Safety Staff have put tremendous effort into developing a rigorous methodology that will ensure that the proposed undergrounding projects that will be passed on to the CPUC will be highly vetted and ready for appropriate Commission action. MGRA has incorporated new information acquired during the 2025 WMP Update reviews that allows for significant improvements in some aspects of the Guidelines.

MGRA will use the OEIS numbering scheme to raise its comments.

1 EXECUTIVE SUMMARY

1.2 Purpose and Scope

Page 1 - The original language of the Draft states that:
"*the EUP can only be approved if (1) it will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and (2) it will substantially reduce the risk of wildfire. To support this, the EUP must include the Portfolio Mitigation Objective, and specific objectives and targets as described below*."

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[1] Docket #2023-Ups; TN14039; OFFICE OF ENERGY INFRASTRUCTURE SAFETY DRAFT 10-YEAR ELECTRICAL UNDERGROUNDING PLAN GUIDELINES; May 8, 2024 (Draft).
[2] Docket #2023-Ups; TN14049; Letter Re: Draft Electrical Undergrounding Plan Guidelines; May 8, 2024.

MGRA recognizes that OEIS is following the lead of 8388.5(d)(2) in putting the role of undergrounding as primarily to increase reliability and secondarily to reduce the risk of wildfire. However, this emphasis may be misguided. When power shutoff as a strategy was first purposed by SDG&E in 2009, MGRA suggested that the correct way to determine power shutoff thresholds and mitigation would be to do a cost/benefit analysis, a proposal that was adopted by the Commission.[3]

It appears that the Draft Guidelines would adequately ensure a cost/benefit analysis be carried out for the wildfire risk presented by circuits in the study. In wildfire risk reduction, a number of mitigations adequately compete with undergrounding, specifically combinations of covered conductor and advanced electronic technologies capable of detecting faults and neutralizing line currents, or identifying incipient faults before they manifest.

2.3.2 Objectives and Targets

Transparency:

On p. 6, the Guidelines state that "*The EUP must include this list of In-Area Circuit Segments along with the following risk scores for each Circuit Segment: (i) Overall Utility Risk Score; (ii) Ignition Consequence Score; and (iii) Outage Program Reliability Score. Section 2.7.9 of these Guidelines details the requirements for these risk scores.*

The EUP must contain three versions of the All Circuit Segment List, sorted by (i) Overall Utility Risk Score; (ii) Ignition Consequence Score; and (iii) Outage Program Reliability Score"

MGRA is glad that the utilities are being required to disclose a significant amount of data that will allow their projects to be evaluated. However, based on MGRA interaction with utilities since 2022, utilities seem to becoming less, not more transparent in the data they are willing to disclose without a Non-Disclosure Agreement in place. Hence for members of the public to engage with this data they must either: 1) sign an NDA with all utilities for which they want the data, or 2) ask the utilities for data with sensitive data redacted. Many members of the public may not wish to sign an NDA with the utilities for a number of reasons:

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[3] D.09-09-030; pp. 55;
A.08-12-021; MGRA Opening Comments; Appendix A; Mitchell, Joseph W; M-bar Technologies and Consulting, LLC for the Mussey Grade Road Alliance; "WHEN TO TURN OFF THE POWER? COST/BENEFIT OUTLINE FOR PROACTIVE DEENERGIZATION"; March 27, 2009

- It puts them at legal and financial risk if data is accidentally lost or stolen
- It strongly limits what the public can say publicly about the utility programs without fear of transgressing the limit of the NDA.
- Utilities have been known to disclose "secret" information confirming stakeholder concern over programs, only to have stakeholders prevented from raising those concerns.

There has also been a pattern of overuse, with more utilities now agreeing that "consequence" data is confidential, which is a ridiculous premise considering that utility infrastructure has nothing to do with wildfire consequences on worst-case weather days. These are simply weather/vegetation hazard maps, the same as those produced by Cal Fire, but at a much finer scale. If a bad actor wishes to start a fire in a bad place they can easily do so using existing maps and would not be aided by utility consequence maps.

Likewise, knowing where ignitions and outages are likely to occur provides little information available to the ill-intended that would help them harm utility infrastructure.

While MGRA acknowledges that there are third-party threats to infrastructure, particularly transmission infrastructure, and supports utility efforts to manage those threats, we believe many of the recent Declarations made regarding confidentiality have been overbroad. We have, unfortunately, had little time to challenge them up to this point. But this may be the last chance to do so, because if utility undergrounding applications are grounded in secrecy from the start there will be few means for the public to monitor or challenge them once they move forward.

Energy Safety also imagines a 30 day public comment period will be adequate (it isn't and this will be raised in another section), and if haggling over the data formats and what is available takes up the time available for data requests this will leave essentially no time for data to be analyzed prior to the deadline. This scenario has already had negative consequences for MGRA in the 2025 Update WMP reviews, as MGRA planned to do a more extensive analysis of PG&E's EPSS program, relating it to weather conditions at the time of outage. This was not possible due to the extreme data restrictions PG&E placed on its GIS outage data.

We would ask that Energy Safety as part of these Guidelines and prior to accepting applications from utilities resolve this problem:

- Energy Safety should determine what data fields may properly be classified as confidential and which should be in the public domain.
- Where utilities are required to provide data as part of their SB884 submission, they should be required to release both public and secure versions of these data.
- Where data is redacted it should be done in the most non-destructive manner that still protects the confidential information – reassigning names/numbers to random elements and adding "wiggle" to location data may still provide adequate information for public scrutiny without causing harm.

2.4.2 Screen 2: Project Information and Alternative Mitigation Comparison

Alternative Mitigations

The Draft Guidelines mandate that: "*The alternative mitigation comparison must include a comparison of at least two alternative mitigations*." MGRA believes this requirement needs to be much more prescriptive due to utility history of avoiding beneficial comparisons.

MGRA has had long experience in trying to persuade or mandate utilities to combine mitigations into the most effective combination for comparison against undergrounding. As we've noted, utilities have a perverse incentive to underground because it is more highly profitable than other forms of mitigation due to the 10% return on equity they receive for working on capital projects. For this reason, it may be better to use more prescriptive directions for utility mitigation comparisons rather than leave them to the utilities. The optimal combination will also depend upon the technologies and infrastructure the utility has available.

Using an example from the 2025 Update analysis of PG&E's submission, we find the following example and MGRA's reaction to it.

TABLE ACI-PG&E-23-05-3:
IGNITION MITIGATION EFFECTIVENESS: REPRESENTATIVE BLENDED AVERAGE VALUES

Scenario	Blended Average Effectiveness[(a)]
Alt. 1 – Baseline	0%
Alt. 2 – Underground Primary	97.7%
Alt. 3 – Underground All	99.2%
Alt. 4 – Covered conductor (CC) Overhead with EPSS	78.2%
Alt. 5 – Bare Conductor Rebuild with EPSS and downed conductor detection	60.9%
Alt. 6 – Line Removal w/ Remote Grid	97.7%
Alt. 7 – EPSS including downed conductor detection (DCD)/Partial Voltage (with bare conductor)	60.4%
Alt. 8 – EPSS and PSPS (with bare conductor)	91.3%
Alt. 9 – Rapid Earth Fault Current Limiter (REFCL), CC Overhead, EPSS and DCD	65.0%
Covered Conductor Rebuild – New	66.4%(b)

Assumptions:

- Analysis assumes no Overhead degradation for life of the asset;
- EPSS and DCD are only active when conditions are greater than R1;
- Ground sensitivity on 4 wire systems for high impedance faults similar to DCD mitigation; and
- Mitigation effectiveness for other Environmental caused outages: None for Overhead and All for Underground.

(a) These are averages based on review of 8 years of outage history between 2015 and 2022. This historical review differs from the methodology used to calculate the annual effectiveness reported by PG&E for any given year.

All of these effectiveness values represent a blended average effectiveness at the circuit segment level with the exception of "Alt. 9 – REFCL, CC Overhead, EPSS and DCD" which is a substation effectiveness score. Not all substations are capable of having REFCL applied, and it cannot be isolated to a circuit segment only.

The approach to calculating outage risk considered the following outage types, however they were deemed not applicable and therefore excluded:

No improvement for existing Underground Type outages; and

All company-initiated outages, Community Wildfire Safety Program and PSPS outages fire forest/grass outages – potential wildfire cause outage/force out.

(b) The mitigation effectiveness value for CC used in the WBCA (66.4%) is similar to the value arrived at as part of the joint California IOUs CC effectiveness study for 2022 (64%). See PG&E's 2023-2025 WMP, Revision 1, April 26, 2023, page 900.

Table 1 - PG&E's claimed ignition mitigation effectiveness table using blended averages**,** as shown in its 2025 Update WMP, Table ACI-PG&E-23-05-03

MGRA does not find PG&E's arguments supporting this table or its completeness convincing. As stated in MGRA's WMP Comments: "*First, there is clearly no mitigation that approaches the effectiveness of covered conductor on its own. However, PG&E shows covered conductor only in Alternatives, 4, 9, and "Covered Conductor Rebuild". Finally, the "ultimate" combination, listed as alternative 9, with REFCL, EPSS, DCD, in combination with Covered Conductor rates as only 65% effective, whereas it estimates that covered conductor alone has a 66.4% efficiency. PG&E's explanation is that this is a "substation effectiveness score", since it claims that not all substations are REFCL-capable.*"[4]

[4] MGRA 2025 WMP Comment; p. 43.

PG&E explained that this analysis was applied to only selected circuits, to which MGRA responded that "*REFCL on its own is estimated to have a 50% efficiency even stated by SCE, and sources in Australia see much higher efficiencies.*[5] *Covered conductor, in addition, is estimated by PG&E to have 66% effectiveness alone, and DCD specifically compensates for the CC vulnerability most likely to lead to catastrophic wildfire – tree fall in. On top of that, EPSS has been shown to be extremely effective in reducing ignitions – initial results of 80% were reported by PG&E.*[6] *While some of the protective effects of these multiple layers of protection may be redundant, some in fact are complimentary, such as DCD and covered conductor*."[7]

This was not a problem isolated to PG&E.

Energy Safety should require that at least one non-UG solution should combine at least:

- Covered conductor
- REFCL (if applicable for the utility/segments)
- Downed/open conductor protection
- "Fast trip"/EPSS settings
- High impedance fault detections
- Electronic Fault Detection

Finally, MGRA has published an analysis of SCE field data showing definitively that covered conductor has an effectiveness of 85% in reducing wildfire ignitions, rather than the 65-72% used by the major IOUs.[8]

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[5] Marxen, T., 2019. How do Victoria's REFCLs deliver more fire-risk reduction than simple theory and experience elsewhere say they should? | LinkedIn [WWW Document]. URL https://www.linkedin.com/pulse/how-do-victorias-refcls-deliver-more-fire-risk-than-simple-marxsen%3FtrackingId=YoM4zpCp9cG1uYmCn5Lkcg%253D%253D/?trackingId=YoM4zpCp9cG1uYmCn5Lkcg%3D%3D (accessed 5.16.23). Also,
PG&E Data Request Response WMP-Discovery2023_DR_CalAdvocates_011-Q008g.
REFCL Functional Performance Review; Report for Energy Safe Victoria; PSC Reference: JA8648-0-0 REFCL Functional Performance Report. (Downloaded 2/24/2024).
https://www.esv.vic.gov.au/sites/default/files/2022-12/REFCL-Functional-Performance-Review.pdf

[6] PG&E 2022 WMP; p. 738.

[7] MGRA 2025 WMP Comments; p. 44.

[8] Id.; pp. 22-24.

Customer PSPS Avoidance Cost

Another screen that should be applied to circuits due to the emphasis of SB 884 on improving reliability is the cost of PSPS avoidance per customer for a given circuit. Data and analysis supporting this potential metric constituted a considerable portion of MGRA's Comments on the 2025 Update.[9] Looking at the language of SB884 once again:

"*…the EUP can only be approved if (1) it will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and (2) it will substantially reduce the risk of wildfire. To support this, the EUP must include the Portfolio Mitigation Objective, and specific objectives and targets as described below*."

It is clear that substantial improvement of reliability must be demonstrated in the IUP. Unlike wildfire risk, which is distributed over a wide area so that a faulty component can potentially cause significant harm miles away, PSPS risk affects only the customers on the circuit itself. This calls for an alternative reliability metric that can track how efficient undergrounding mitigation is, a metric that will prove vitally important to the CPUC's later analysis and approval of the IUP.

To begin with a *reductio-ad-absurdum* argument, what if a 20 mile circuit segment supports only one customer. At a cost of $3 million per mile for undergrounding this single customer would cost other ratepayers $60 million to keep on the grid. Surprisingly, there are some circuits segments that approach these costs. To measure how much of an effect each of these long and poorly served circuits have, MGRA presented two metrics: The first was an "counterfactual" metric based on number of customers per circuit that would pay for off-grid customer solutions if cost per customer exceeded $60k. The other metric is the cost to reduce 1 minute of PSPS time through an undergrounding solution using both customer and historical PSPS data. MGRA was able to successfully perform this analysis for both PG&E and SDG&E data. The results are below:[10]

[9] MGRA 2025 WMP Comments; pp. 27-49.

[10] Id.; Raw data taken from MGRA 2025 Update Workpapers https://github.com/jwmitchell/Workpapers/tree/main/WMP25

	SDG&E 2023 Data	SDG&E 2025 Projection
Projected cost	$118 million	$182 million
Customers	10,042	4,410
Cost / Customer	$11,785	$41,422
Savings at $60 k Off-Grid cutofff	17%	35%

Table 2 - Cost per customer for SDG&E underground segments completed in 2023 and slotted for completion by 2025. Counterfactual potential savings from "off-gridding" customer segments costing more than $60k per customer is also shown**.**

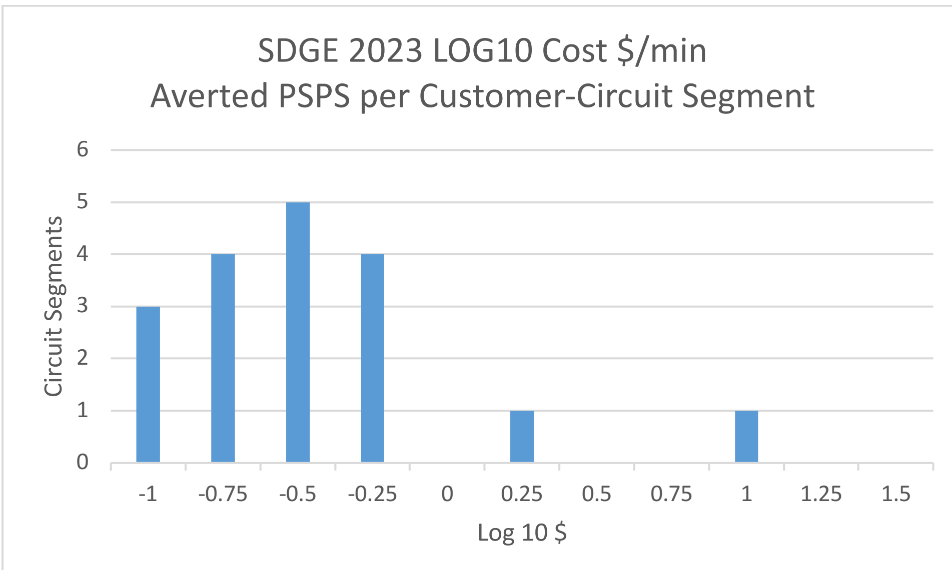

Figure 1 - Cost per avoided PSPS minute for each grid segment in the SDG&E 2023 undergrounding program. The scale is logarithmic.

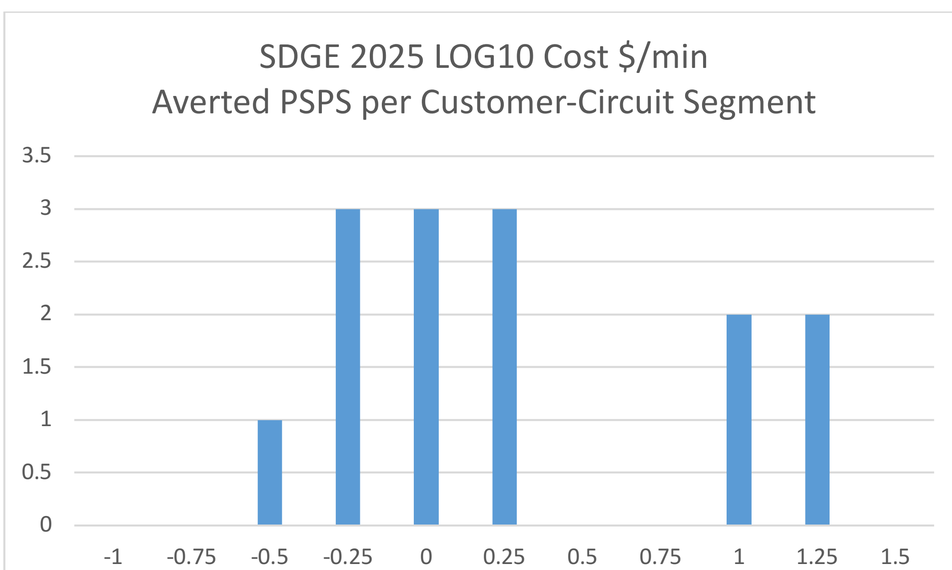

Figure 2- Projected cost per avoided PSPS minute for each grid segment in the SDG&E 2025 undergrounding program. The scale is logarithmic.

As is shown in Figure 1, the cost to avoid a customer PSPS minute varies widely between circuits with a range of two orders of magnitude (from ~$.01 to $10)

A similar analysis was applied to PG&E data:

	PG&E 2023 Data	**P&E 2025 Projection**
Projected cost	$1.18 billion	$3.4 billion
Customers	31,399	18,640
Cost / Customer	$42,689	$87,811
Savings at $60 k Off-Grid cutofff	38%	56%

Table 3 - Cost per customer for PG&E underground segments completed in 2023 and slotted for completion by 2025. Counterfactual potential savings from “off-gridding” customer segments costing more than $60k per customer is also shown.

Cost to reduce a customer PSPS-minute is shown in the graph below:

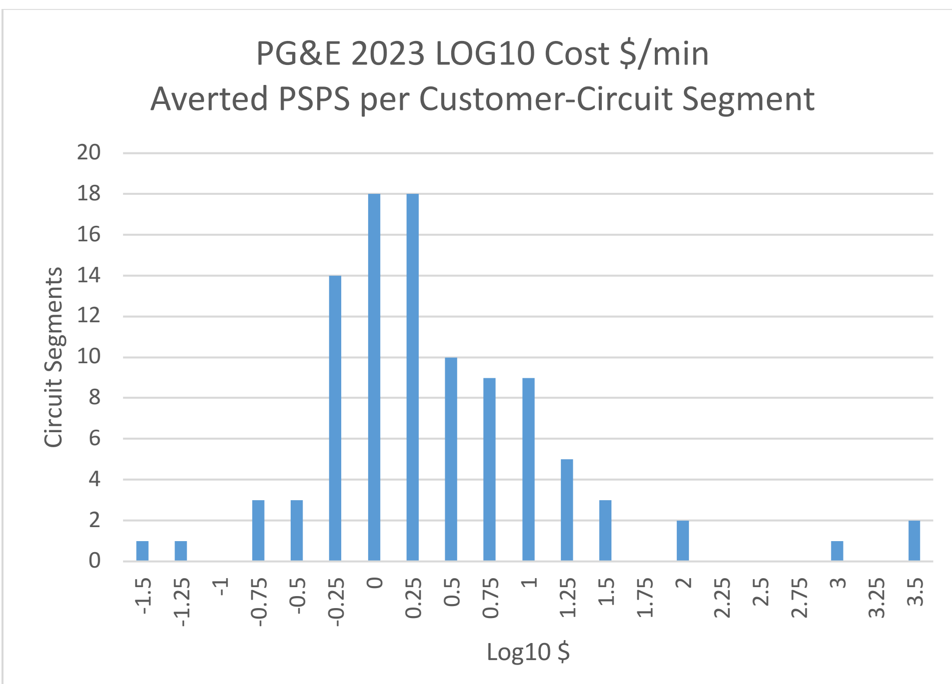

Figure 3 - Cost per avoided PSPS minute for each grid segment in the PG&E 2023 undergrounding program. The scale is logarithmic.

As is evident, the cost to reduce a PSPS-minute in the PG&E territory varies much more than that in the SDG&E territory: by five orders of magnitude (a few cents to a few thousand dollars).

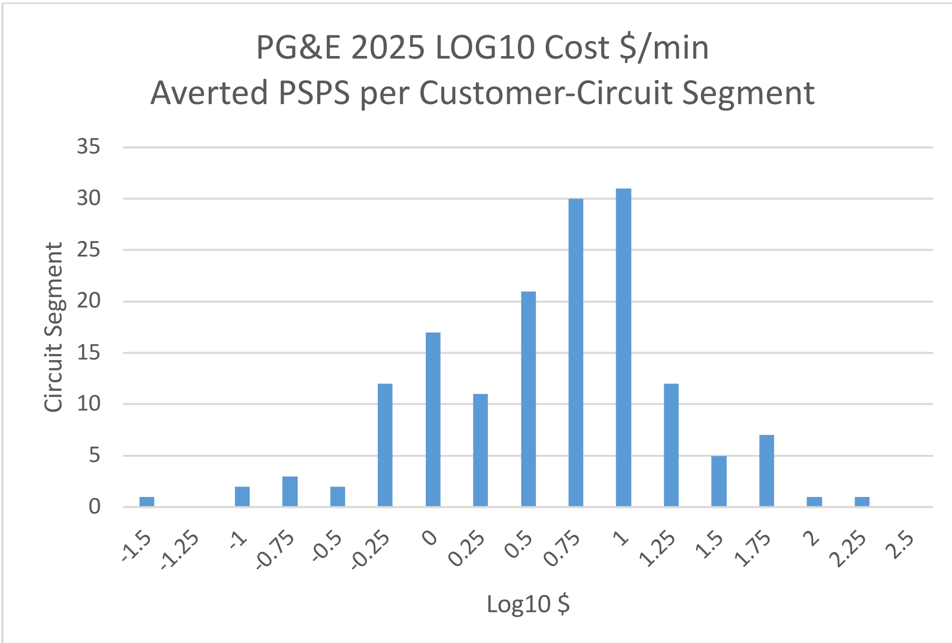

Figure 4 - Cost per avoided PSPS minute for each grid segment in the planned PG&E undergrounding program through 2025. The scale is logarithmic.

Note that PG&E's undergrounding program through 2025 will cost roughly 10 times more per customer PSPS minute averted than the undergrounding work that PG&E has already completed.

Comments on the cost of PSPS customer avoidance:

- These are optimistic estimates, since in order for customers to avoid PSPS *all* circuit segments supplying the customer must be treated.
- Some circuits showed zero customers (and therefore infinite cost per PSPS minute avoided. One might optimistically assume that these circuit segments are being treated only for their wildfire risk, subject to check.
- The $60k cutoff is assumed to be the cost of a stand-alone solar installation with storage, but such a solution is not currently practical with existing regulations. However, such high-cost circuit segments should not be prioritized for undergrounding. Instead, covered conductor with supplemental advanced technology should provide sufficient wildfire ignition protection, and under extreme conditions these circuits should also be subject to

PSPS and EPSS as appropriate. The CPUC could potentially consider providing grants for long-term battery storage for customers on these circuits, which would still cost substantially less than undergrounding the circuit segments.

- Both PG&E and SDG&E have exhausted the "low hanging fruit" in their undergrounding programs and are reaching a point where returns in terms of reliability are reduced ten-fold below what they were in 2023 per dollar spent.
- I was not able to understand the data from SCE but it would be worth looking at if it can be had in a more comprehensible format.
- It is not the mission of OEIS to make reliability "affordable" but rather to eliminate or severely reduce PSPS and EPSS. It will be up to the CPUC to determine whether circuits are acceptable due to cost within an undergrounding project. However, in order to facilitate a solution compliant with SB 884 Energy Safety should ensure that the CPUC has all the metrics it needs to make optimal decisions, including the cost of reliability.

2.7 Risk Modeling

Table 2:

Comments regarding Table 2:

- Cross reference to latest risk model information in the WMP.
- There should be both confidential and public redacted versions of supplemental documentation.
- Add: VALIDATION - This section should describe how the model was tested and validated to ensure accuracy. References to third-party assessments should be provided.

2.7.3 Key Decision-Making Metrics and Enterprise Diagrams

Core Capability 6: Comparisons with Alternative Mitigation Strategies

The Draft Guidelines would require that "*All reasonable combinations of these alternative mitigations must be considered, unless a reason is given for exclusion of a permutation (e.g., two incompatible strategies would be used). This must include at least two alternative mitigations*."[11] For the reasons described in Section 2.4.2, utilities must be given limited discretion and more direction in their choice of alternative mitigations.

This would be better stated more prescriptively: "*This must include at least three alternative mitigations that have been found to have the highest effectiveness in combination with covered conductor.* There is a risk with the language as stated that the utilities would pick covered conductor as one of their two choices, leaving them with only one alternative mitigation to work with. They also are under no obligation to use their most effective combination with covered conductor unless the language is more prescriptive. In fact, as OEIS learns more about the details utility alternative mitigations, it may consider specifying alternative mitigations explicitly.

Figure 1, p. 20:

The weather model box in Figure 1 should show an additional arrow (causal linkage) between the weather model and the consequence model. Weather is a driver for outage rates, ignition potential, and fire growth.[12]

p. 24 – Model inputs

Weather should include type of weather modeling if used, version and input parameters, as well as weather history set used in the model.

2.8.7.1 Project Index Table

Add: Cost per minute of averted PSPS.

[11] Draft Guidelines; p. 24.
[12] Mitchell, J.W., 2013. Power line failures and catastrophic wildfires under extreme weather conditions. Engineering Failure Analysis, Special issue on ICEFA V- Part 1 35, 726–735. https://doi.org/10.1016/j.engfailanal.2013.07.006

3.5.1 Examples Warranting a Modification Notice

Add: 15 day public comment period for modification notice response

C.1.9 Screen 2 Table

Add: *unit_cost_per_customer_PSPS_minute_avoided* in Tables C.9 and C.13.

Add: *linked_projects_to_achieve_PSPS_resilience*

Reason – There are some projects that might need to be completed in tandem to provide PSPS resilience for some customers.

GENERAL

Public Feedback

30 days is an insufficient time for public feedback for projects that have a 10 year impact on rates and safety. It is also insufficient time to gather the data requests necessary to understand the modeling and project details. While the OEIS process is limited to 9 months, it should not require 8 months for OEIS to process public input. A period of 45-60 days should be allotted for public input, plus 15 day comment periods on modifications.

Project Mutability

Another concern is that a "project" is mutable, in that changes can be made that alter the model and thereby affect the selected circuit segments. This potentially allows an exploit wherein a utility can submit a project with a set of specified circuit segments, complete some of these segments, alter its model in a way to include more circuit segments (which would be "waived into" an approved project, complete the new segments, alter its model again to include even more segments, etcetera. Changes to the models constituting an approved project should open up another public review process if the model changes result in a substantive change to the set of circuit segments to be treated.

Timelines

Looking at the full lifespan of a project should occur during Screen 2 and not at Screen 3. Overall benefit and cost over lifecycle can substantially affect the optimal set of choices for circuits and mitigations. By Screen 3, the project is approved and this information is no longer of significant use in making these choices.

CONCLUSION

The Mussey Grade Road Alliance respectfully requests that Energy Safety consider its comments and take all measures to ensure that undergrounding plans are a public benefit. MGRA and other stakeholders have requested a number of checks, balances, and safeguards that would help both the CPUC and Energy Safety successfully meet criteria set forth in PUC Section (§) 8388.5 ensuring rapid deployment of mitigations while ensuring ratepayer protections.

Respectfully submitted this 29th day of May, 2024,

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