TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Northern California
360 Grand Avenue, #150
Oakland, CA 94610
415 929-8876 • www.turn.org

Southern California
1620 Fifth Avenue, Suite 810
San Diego, CA 92101
619 398-3680 • www.turn.org

Comments of The Utility Reform Network on Electrical Undergrounding Plans (Docket #2023-UPs) Request for Comments on Development of Guidelines for the 10-Year Electrical Undergrounding Distribution Infrastructure Plan (Undergrounding Plan)

Senate Bill (SB) 884 directs the California Public Utilities Commission (CPUC or Commission) to establish an expedited utility distribution undergrounding program consistent with the requirements of Public Utilities Code Section 8388.5. The process described in the statute includes the submission by a utility that so elects of a proposed undergrounding plan to the Office of Energy Infrastructure Safety (Energy Safety). The Request for Comment issued by the Electrical Undergrounding Division identifies questions for response as Energy Safety develops its guidelines for review of the undergrounding plans. These comments will inform an upcoming series of working group meetings all of which will presumably inform Energy Safety's ultimate guidelines for the SB 884 Undergrounding Plans. TURN offers the attached initial comments on the questions posed by Energy Safety and looks forward to discussing these issues further in the upcoming working group sessions as TURN's resources allow.

The CPUC previously submitted a Staff Proposal for the CPUC process for review of utility plans. TURN and other interested parties submitted informal comments on that plan. Given the joint responsibility of Energy Safety and the CPUC to review and approve the plans, the requirements and review at Energy Safety should be informed by the process at the CPUC and vice versa. TURN recommends that both Energy Safety and CPUC adopt Appendix 1 outlined in the CPUC Staff Proposal as modified by TURN (Modified Appendix 1) (attached) as discussed further below. These comments by TURN are intended to complement the comments previously provided on the CPUC Staff proposal.

1. Consistent with the Statute, Energy Safety's Review Should Include a Comparison of the Cost-Effectiveness of Undergrounding with Alternative Mitigations

Before addressing the specific questions posted by Energy Safety, TURN highlights specific language in the statute that informs its understanding of the requirements for Energy Safety's review of the plans and TURN's responses to the questions posed by Energy Safety.

Section 8388.5(c) lays out the requirements for a utility "distribution infrastructure undergrounding plan." The requirements include:

(1) "A 10-year plan for undergrounding";[1]
(2) Identification of all projects included in the plan and the "means of prioritizing undergrounding projects on wildfire risk reduction";[2]
(3) Timelines for the projects;[3]
(4) A comparison of the projects against alternatives "emphasiz[ing] risk reduction and including an analysis of costs;[4]
(5) Plans for "workforce development";[5] and
(6) Evaluation of costs and economies of scale.

[1] Section 8388.5(c)(1).
[2] Section 8388.5(c)(2).
[3] Section 8388.5(c)(3).
[4] Section 8388.5(c)(4).
[5] Section 8388.5(c)(5).

Section 8388.5(d)(2) expressly directs Energy Safety: "Before approving the plan, the office may require the large electrical corporation to modify the plans." As an initial matter, Energy Safety's approval must determine that the utility has provided all required elements of the plan including the 6 items identified above.

Section 8388.5(d)(2) directs that Energy Safety can only approve a utility plan that "will substantially increase reliability…and substantially reduce the risk of wildfire." Part I of the Request for Comment focuses on this language and poses questions regarding how this language should be interpreted. However, Section 8388.5 makes clear that the subsection (d)(2) requirements do not comprise the entirety of considerations that Energy Safety must address in its review of a utility plan. Energy Safety must also consider each of the required elements of Section 8388.5(c), which include the following:

> (4) A comparison of undergrounding versus aboveground hardening of electrical infrastructure and wildfire mitigation for achieving comparable risk reduction, or any other alternative mitigation strategy, such as covered conductor and rapid earth fault current limiter devices, for those prioritized undergrounding projects, evaluating the scope, cost, extent, and risk reduction of each activity, separately and collectively, over the duration of the plan. The comparison shall emphasize risk reduction and include an analysis of the cost of each activity for reducing wildfire risk, separately and collectively, over the duration of the plan.

Thus, the statute requires Energy Safety ensure that the proposed undergrounding plan would implement undergrounding projects only where it represents the best approach for reducing risk in a cost-effective manner compared to other alternatives. Ignoring the language in Section 8388.5(c) would violate the fundamental principle of statutory interpretation that "Every word within a statute is there for a purpose and should be given its due significance."[6] Unless Energy Safety ensures that these required elements have been given due weight in its consideration of the plan, the language of Section 8388.5(c) would be rendered meaningless.

2. Responses to the Energy Safety Questions

a. "Outage Program" Should Include Proactive Deenergizations of All Kinds

Energy Safety requests that stakeholders suggest a definition for "outage program" which is otherwise undefined in the statute. Other reliability programs identified in the statute include existing programs like Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS) and deenergization programs which are defined as "the proactive interruption of electrical service for the purpose of mitigating or avoiding the risk caused by a wildfire."[7]

The definition provided for "deenergization program" is broad enough to encompass other outage programs that are intended to address wildfire risk. For the phrase "outage program" to have specific and different meaning from deenergization program, it should be considered broadly refer to any other proactive deenergization for any reason, whether or not related to wildfire risk, such as, for example, maintenance outages. This broader definition of the phrase is appropriate to avoid redundancy in the statute cover other and future, as yet unspecified programs, that would result in less reliable service for utility customers.

---

[6] https://www.supremecourt.gov/DocketPDF/18/18-9575/102239/20190611092122150_00000055.pdf; Cal. Code of Civ. Proc. Section 1858 (in the construction of a statute, "the office of the Judge . . . is not to omit what has been inserted . . . and where there are several provisions or particulars, such a construction is, if possible, to be adopted as will give effect to all.")
[7] Section 8388.5(c)(3).

For example, interpreting "outage program" to include maintenance outages could impact the comparison of hardening alternatives. Energy Safety should consider not only whether undergrounding may result in some increase in maintenance outages but also how that number would compare to other mitigation alternatives. For instance, Energy Safety should assess any potential differences in overhead and underground infrastructure maintenance and whether maintenance outages are more common with one type of infrastructure and their relative impacts on reliability of service to end customers.

b. Reliability Benefits Should be Compared Not Just to a Baseline but Also to Alternative Mitigation Options.

To approve the plans, Energy Safety must determine that the plan will result in substantial improvements to reliability. In other words, Energy Safety should determine that the plan will reduce reliance on PSPS, EPSS, deenergization and other program outages. Energy Safety requests comment on "a methodology for determining a level of reliability that should be used as the baseline level of reliability against which any assessment is made."[8]

Assessment of Reliability Benefits Should Include Comparison to Alternatives. The format of the question assumes that there is a single baseline against which the assessment is made. The statute instead states that undergrounding must "substantially" increase reliability. Giving proper meaning to the entirety of the statute, including the considerations set forth in Section 8388.5(c)(4), the proper comparison is not just against a single baseline but also against all potential alternatives to undergrounding installed in the same locations. Further the comparison should incorporate the cost and timeline for completion provided by the utility, considerations that are required by Section 8388.5(c)(3) and (6). This reading is affirmed in the Assembly Analysis of the bill which states approval will "based on specified showings including a substantial increase in electric reliability, and substantial improvements in safety risk and reduction in costs compared to other hardening and rise mitigation measures."[9]

For example, overhead hardening will reduce the need for PSPS and EPSS by, among other things, increasing the wind speeds that the line will withstand. The utility should provide and justify its intended wind speed thresholds for overhead hardened lines for each project. These data points can be used to assess the extent to which undergrounding provides incremental customer reliability impacts in that project location that justify the additional costs and complexity of undergrounding.

Baseline Should Include All Work Prior to Implementation of the Proposed Plan. TURN proposes that the baseline to which both undergrounding and other alternatives will be compared be set at the time the plan is approved and incorporating all projects that the utility will complete by the projected date of approval.[10] The utilities are already implementing hardening solutions-- both overhead and underground-- and the impact of all projects scheduled to be completed by the date of approval should inform the baseline. If the baseline were set at any point earlier in the process it would overstate the impact of the projects included in the plan.

For example, regarding PSPS, the utilities have already made significant improvement in the reliability of service to customers. For instance, in its 2023 WMP, PG&E reports that it had 8 events impacting over 2 million customers in 2019 and the 5 events impacting only 80,000

[8] Request for Comment, p. 1.
[9] Assembly Analysis, Aug. 26, 2023, p. 1, available at: https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202120220SB884#
[10] TURN notes that PSPS information in terms of customer count and minutes is provided within the WMP. Further, the utility submits to the Commission information on EPSS events. Otherwise, the utility should provide the requested data subject to audit.

customers in 2021.[11] In 2022, the utility had no deenergization events.[12] So far, PG&E has reported three PSPS events in 2023 to the CPUC.[13] PG&E's actions and management of its grid and PSPS events have reduced the impact of its events in terms customers impacted by PSPS events. If the baseline is not set based on the state of the infrastructure at the time of approval, it will present a false picture of the impact of the ten-year plan on PSPS.

c. A Finding of Substantiality Will Require Large Improvement

The statute states that a plan can only be approved if it "substantially" increases reliability and "substantially" reduces wildfire risk. This term is not defined by statute and Energy Safety seeks comment on how it should interpret the term. While dictionary definitions do not specifically quantify the meaning of substantial, they indicate that the word connotes a large quantity or important amount. Merriam Webster defines substantial as "considerable in quantity: significantly great."[14] Cambridge Dictionary defines it as "large in size, value and importance."[15] Dictionary.com defines substantial as "of ample or considerable amount, quantity, size, etc."[16]

It is not necessary to adopt any one definition or quantification of substantiality at this time. Instead, satisfying this requirement will depend on a finding that undergrounding provides a large or considerable amount of reliability and risk reduction improvement as compared to alternative approaches available to the utility. The determination of substantiality should also consider the reliability and safety (discussed further below) improvements achieved for the costs and time required of undergrounding as compared to the alternatives, both on project and plan bases.

d. Wildfire Risk Reduction Benefits Should be Compared Not Just to a Baseline but Also to Alternative Mitigation Options.

Energy Safety also seeks comment on how it should determine the baseline for wildfire risk. Similar to its position on reliability risk, TURN recommends that the baseline used to determine whether the plan will substantially reduce wildfire risk be based on the wildfire risk at the time that the plan is approved. The baseline should incorporate all wildfire mitigation work that is scheduled to occur up to the time that the plan is scheduled to be approved. By setting the baseline date at the time of approval, it will ensure that the Energy Safety does not include any projects that are outside of the plan but will impact the safety profile of the utility. Once the baseline is identified, Energy Safety should compare the potential wildfire risk reduction provided not just by the undergrounding projects proposed but also by alternatives to each undergrounding project.

The utilities report ignition risk at individual locations as part of their Wildfire Mitigation Plan. This value, with PSPS Risk, is rolled up to an Overall Utility Risk number for the utility territory. The wildfire risk number, in isolations should be used to set the baseline. Risk values should be calculated consistent with the direction provided by the CPUC in D.22-12-027.

Considering that the development of the baseline and determination of substantial impact will require assumptions to forecast wildfire and reliability risk, TURN notes the importance of an opportunity to submit discovery on the utility plans. Given the 9 months provided for the review and approval of the plans at Energy Safety, TURN recommends that, consistent with the review of the Wildfire Mitigation Plans, Energy Safety direct a three-business day turnaround for data

---

[11] PG&E 2023 WMP Filing Revision 8/7, p. 864, T.9-1.
[12] *Id*.
[13] https://www.cpuc.ca.gov/consumer-support/psps/utility-company-psps-reports-post-event-and-post-season
[14] https://www.merriam-webster.com/dictionary/substantial (meaning 3.b)
[15] https://dictionary.cambridge.org/us/dictionary/english/substantial
[16] https://www.dictionary.com/browse/substantial

requests.

e. Energy Safety's Determination of Substantial Wildfire Risk Reduction Should Incorporate Information on Cost, Timeline and Prioritization.

Consistent with the discussion above, Energy Safety's determination of whether a plan "will substantially reduce the risk of wildfire" should be informed not just by absolute risk reduction of the plan, but by the risk reduction potential of the plan as compared to the alternatives. As discussed, this comparison is required to give full effect to the provisions of Section 8388.5(c).

Absolute risk reduction of the plan in isolation is not helpful if the benefits are delayed or unaffordable for customers. Since the utility will be providing Energy Safety information on timing (Section 8388.5(c)(3)) and cost of the plan and alternatives (Section 8388.5(c)(4)), Energy Safety should use this information to assess whether the individual projects as well as the plan will provide substantial benefits to Californians as compared to the alternatives. The combination of faster installation and lower costs for overhead hardening will, for many locations, mean that more safety could be delivered to more customers through overhead hardening. If, however, Energy Safety looks at the risk reduction from undergrounding in isolation, it will miss these potential safety benefits.

Additionally, Section 8388.5(c)(2) requires the utility to identify "a means of prioritizing undergrounding projects based on wildfire risk reduction." Prioritization information is a key input to determining whether the plan is providing substantial benefits. As stated in TURN's informal comments on the CPUC Staff proposal: "As a matter of statutory compliance and the sound policy of targeting grid hardening where it is most needed, utilities should be required to prioritize hardening in the highest risk locations first before hardening in lower risk areas."[17] Prioritization is key to finding that the utility plan will substantially reduce wildfire risk: the utility should be acting to mitigate the highest risk locations first rather than allowing risky conditions to continue. Energy Safety should only find that the plan will substantially reduce risk if the utility has adequately prioritized its work.

f. Projects Should Be Defined as Previously Recommended by TURN and Other Advocates.

The Request for Comment asks how "undergrounding project" should be defined. A consistent definition of project should be adopted for both Energy Safety and the CPUC. The April 26, 2023 joint letter from TURN, the Public Advocates Office and Mussey Grade Road Alliance states "In the context of a 10-year plan, a project is a self-contained set of activities at a circuit or sub-circuit level, which can be independently assessed for its ability to reduce wildfire risk, cost and timing. Projects can be scheduled, mapped, and prioritized." TURN recommends that this definition of project be adopted by Energy Safety and the CPUC.

TURN does not currently have a recommendation for a minimum or maximum size requirements but anticipates additional discussion of this issue in working group sessions to determine if such requirements are needed.

g. Energy Safety Should Adopt the CPUC Proposed Appendix 1 as Modified by TURN to Capture Project Information.

Energy Safety states that it "intends to require…the circuit number, mileage, and location" and asks what other information should be provided.[18] TURN highlights the Staff Proposal issued by the

[17] TURN Informal Comments on Staff Proposal, p. 2.
[18] Request for Comments, P. 2.

CPUC's Appendix 1 which lists the requirements for included projects.[19] TURN recommends that Energy Safety adopt TURN's Modified Appendix 1 (Attached). Modified Appendix 1 collects the information identified by Energy Safety as well as other points of information that are required for Energy Safety to determine that the undergrounding program provides substantial reliability and safety benefits as compared to both the baseline and alternatives. This includes information such as project identification code and status information, as well as feasibility information that may impact Energy Safety's analysis.

Modified Appendix 1 also requires the reporting of prioritization information, cost, risk reduction and cost benefit ratios of undergrounding projects and their alternatives. As discussed above, these data points are all required for Energy Safety's review and approval of the plan.

h. Prioritization Should Not be Distinguished from Energy Safety's Review of Substantial Risk Reduction.

Energy Safety asks "[h]ow should the prioritization elements be distinguished from the undergrounding plan approval criteria."[20] As noted above, TURN does not agree that the prioritization element should be distinguished from the approval plan criteria. Instead, the prioritization elements should directly inform the determination that the utility plan will substantially reduce risk. Prioritization requirements ensure that the utility is mitigating the riskiest circuits in its system first. If the utility is allowing high risk circuits to remain unhardened in favor of completing lower risk work, Energy Safety should not find that the utility is substantially reducing wildfire risk.

i. Energy Safety Should Require Ongoing Reporting by the Utility of Actual Safety and Reliability Improvements Under the Plan.

Noting that the statute directs utilities to provide information on completion timelines, costs and mileage targets, the Request for Comments suggests that these will be metrics included in the Undergrounding Plans.[21] Energy Safety requests other metrics that should be required from utilities.[22]

As an initial matter, and as highlighted above, the information provided on timelines and costs should inform the Energy Safety review and approval of the plan. These are important inputs to understanding whether the undergrounding plan reduces substantially more safety and reliability risk than the alternatives.

That said, TURN does not oppose these elements also being used as metrics or annual targets by which to track progress under the plan. TURN recommends additional metrics related to prioritization and risk reduced.

- Prioritization: For every project completed, the utility should provide the project's place in the prioritization ranking, i.e. where the miles addressed rank compared to all other HFTD miles. In addition, at the end of each year, the utility should report on the number of projects completed in the top 5% of system wildfire risk, top 10% of system wildfire risk, and each succeeding decile of system wildfire risk. By top x% of wildfire risk, TURN does not mean the top x% of *circuit segments* ranked by risk. Because risk is concentrated in the highest risk segments, PG&E's data shows that 20% of system risk is found in the top 2-5% of miles or circuit segments. Thus, the metric should be based on addressing the highest system risk, not percentage of circuit segments.

[19] CPUC Staff Proposal, pp. 13-15.
[20] Request for Comment, p. 2.
[21] Request for Comment, p. 3.
[22] Request for Comments, p. 3.

- Safety risk: The utility should report the amount of wildfire risk reduced (calculated consistent with D.22-12-027) for each project as well as on an annual basis for all projects.
- Reliability risk: The utility should report the reliability impact on a circuit and customer count for each project and on an annual basis.

These three additional metrics are required for the utility to demonstrate that its actual reduction of risks under an approved plan are consistent with the promised safety and reliability benefits underlying any potential approval of the plan by Energy Safety.

3. Conclusion

TURN appreciates the opportunity to provide this feedback on the questions posed by Energy Safety. TURN looks forward to participating in the Working Group as TURN's resources allow to further develop the Guidelines for Energy Safety's review of the SB 884 undergrounding plans.

Prepared by:

Thomas J. Long, TURN, Director of Legal Strategy
Katy Morsony, TURN, Legislative and Assistant Managing Attorney

November 2, 2023.

INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK (TURN) ON THE CPUC STAFF PROPOSAL FOR THE SB 884 PROGRAM

September 27, 2023

Thomas Long, Dir. of Regulatory Strategy
TLong@turn.org

Katy Morsony, Staff Attorney
KMorsony@turn.org

THE UTILITY REFORM NETWORK

Appendix 1: SB 884 Project List Data Requirements

Field Name	Field Description
Order	Unique Project Order Number.
Category	Work Category Type. Possible values: • Base System Hardening • Community Rebuild • Fire Rebuild • Targeted UG • Other, see comment
Category Comment	Category type not listed in the options above. This field is required if Category is “Other, see comment”.
Project Identification Code	A unique Internal Project Identification code associated with the project and consistent with codes used in GRC and WMP filings (e.g., Maintenance Activity Type Code, Business Planning Element, etc.).
Status	Possible Values: • Scoping: Identifying the proposed route of undergrounding the electric distribution lines, which includes gathering base map data (i.e., Light Detection and Ranging (LiDAR) and survey data of the expected route) and identifying any long lead time dependencies (i.e., land acquisitions, environmental sensitivities and permits). Scoping includes breaking out planned circuit segments into smaller, more manageable projects. Scoping is the first step to providing visibility to the construction feasibility and possible execution timing. • Designing/Estimating: Designing the specific project to determine trench location, connection points, equipment details, materials needed, and related details, such as circuitry and pull boxes. The design also provides information about the land rights needed and produces the drawings that are submitted for permits. The project cost, including expected labor and materials, is calculated at this stage. • Permitting/Dependency: During this stage the large

Field Name	Field Description
	electrical corporation may need to obtain land rights, environmental permits, construction contracts, encroachment permits from local counties, state and/or federal agencies, order long-lead materials, finalize construction cost estimates, and determine the construction schedule. The two longest lead dependencies often include obtaining land rights and environmental permits. • Ready for Construction: Undergrounding project is ready for construction. • 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 due to unanticipated weather, discovery of hard rock, and/or 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, splice segments together and re-connect the customers to the new underground system. Customer input regarding the timing of re-connection, material availability, weather, and other risks can impact the electric construction schedule as well.
Division	Division of the service territory in which the project will take place.
Region	Region of the service territory in which the project will take place.
City	The city in which the project will take place.
County	The county in which the project will take place.
Applicable Risk Model	Name and Version of Project Risk Model used to calculate Cost-Benefit Ratio.
Circuit Protection Zone(s) or Isolated Circuit Segment(s)	All Circuit Protection Zone(s)[21] or Isolatable Circuit Segment(s) included in the project scope.
Project Risk Rank[22]	Results of the applicable risk model where Projects are

[21] A Circuit Protection Zone is a segment of distribution circuit between two protection devices.

~~[22] This information is optional pending whether the large electrical corporation has the necessary data.~~

Field Name	Field Description
	ranked on a 1 to N basis, where 1 is the highest risk Project, and N is the lowest risk.
Project Mean Risk[22]	Summation of the total risk of all pixels (100-meter x 100-meter cell) linked to a Project, divided by the total number of pixels.
HFTD Tier	CPUC High Fire Threat District Tier per D.17-01-009. Possible Values: • Tier 2 • Tier 3
Feasibility Score by Project[22]	Cost multiplier indicating the difficulty of undergrounding the Project based on presence of hard rock, water crossing, and gradient. The scale ranges from 1 to 3, with 3 being most challenging. The utility Application for conditional approval will define each level of the scale.
Cost-Benefit Ratio	Cost-Benefit Ratio of the Project per D.22-12-027. Benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding. ~~The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding~~
Risk Reduction	Risk Reduction of the Project per D.22-12-027.
Unit Cost Per Underground Mile	Project Unit Cost per Mile of Undergrounding.
Unit Cost per Overhead Mile	Project Unit Cost per Mile of Overhead Exposure.
Total Cost	Total Project Cost.
Risk Tranche(s)	Risk tranches include a group of assets, a geographic region, or other grouping that is intended to have a similar risk profile such as having the same likelihood or consequence of risk events.
Overhead System Hardening - Cost Benefit Ratio (separate line for each alternative mitigation or combination of mitigations)[23]	Overhead System Hardening – Cost Benefit Ratio for all alternative grid hardening mitigations or combinations of mitigations to the undergrounding project scored per D.22- 12-027. Calculated for each alternative mitigation or combination of mitigations that is reasonable for the project location. The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding.
Overhead System Hardening - Risk Reduction (separate line for each alternative mitigation or combination of mitigations)[23]	Overhead System Hardening – Risk Reduction for all alternative grid hardening mitigations or combinations of mitigations to the undergrounding project scored per D.22-12- 027. Calculated for each alternative mitigation

	or combination of mitigations that is reasonable for the project location. The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding.
Overhead System Hardening - Unit Cost per Mile (separate line for each alternative mitigation or combination of mitigations)[23]	Overhead System Hardening Project Unit Cost per Circuit Mile. Calculated for all alternative grid hardening mitigations or combinations of mitigations to the undergrounding project. Calculated for each alternative mitigation or combination of mitigations that is reasonable for the project location.
Overhead System Hardening - Total Cost (separate line for each alternative mitigation or combination of mitigations)[23]	Overhead System Hardening Total Project Cost. Calculated for each alternative mitigation or combination of mitigations that is reasonable for the project location. The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding.
Customer Count	Number of customers served by project.

[23] Related to item 10 of the "Application Requirements" section.