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Witness: Eric Borden

REDACTED

PREPARED TESTIMONY OF ERIC BORDEN

ADDRESSING WILDFIRE SYSTEM HARDENING AND CUSTOMER BATTERY PROGRAM ISSUES IN PACIFIC GAS AND ELECTRIC'S TEST YEAR 2027 GENERAL RATE CASE

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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February 13, 2026
Errata March 26, 2026
Second Errata April 24, 2026
Third Errata, May 5, 2026

Summary of Changes in Errata

~~This~~ TURN's previous errata ~~makes~~ made two changes. First, as foreshadowed in Mr. Borden's original testimony, the analysis ~~has~~ was ~~been~~ updated to incorporate the most current information available from PG&E's rebuttal testimony regarding ungerground mileage completed to date. Second, the analysis ~~has been~~was revised to correct an error related to overhead hardening costs identified by PG&E in its rebuttal. ~~Neither change alters TURN's recommendations.~~This errata corrects a calculation error that affects the percent of underground miles in each risk tranche shown in Figures 1 through 4. I also incorporate a supplemental data request response regarding system overhead hardening which corrects a calculation error by PG&E in its previous response. These errata do not affect TURN's conclusions or recommendations.

TABLE OF CONTENTS

PREPARED TESTIMONY OF ERIC BORDEN ADDRESSING WILDFIRE SYSTEM HARDENING AND CUSTOMER BATTERY PROGRAMS

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

This testimony is presented on behalf of The Utility Reform Network (TURN) by Eric Borden.[1] I address Pacific Gas and Electric's (PG&E's) proposals for System Hardening (SH) — undergrounding and overhead hardening. I also address PG&E's proposal for a utility-owned battery program called Customer Battery Infrastructure (CBI), and alternatives to this program structure.

Regarding PG&E's SH undergrounding proposal, the Commission should not approve any ratepayer funding for 2027 for multiple reasons, listed below. Using non-ratepayer funds (i.e. shareholder or other funding sources), PG&E should underground around 191 miles in test year (TY) 2027, based on the number of miles the utility will fall short of the Commission's requirements from the TY 2023 General Rate Case (GRC) decision. This can serve as a "bridge" to the Electric Undergrounding Plan (EUP), if any is needed. In addition, we recommend the Commission require PG&E to deploy undergrounding projects exclusively in the top 30 percent of risk (correctly defined, see Section II). These recommendations are based on the following findings regarding PG&E's undergrounding proposal:

- It is inadequately supported.
    - The proposal is based primarily on the average number of miles adopted in the previous Test Year (TY) 2023 General Rate Case (GRC) decision, as well as a flawed "decision tree" that is biased towards selection of undergrounding even if superior alternatives are available to mitigate risk and appropriately consider affordability.
    - It is impossible to assess PG&E's SH proposal holistically because the

[1] My curriculum vitae is attached to this testimony.

utility did not present a four-year forecast for undergrounding. Likely billions of dollars are missing from this GRC for undergrounding alone, leaving the Commission with inadequate information to assess the SH undergrounding forecast for TY 2027.

- In general, overhead hardening remains a superior alternative to undergrounding.
    - Combined with Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS), it reduces the same amount of wildfire risk as undergrounding and is more affordable.
    - Even without PSPS and EPSS, overhead hardening has reduced more risk at less cost over more miles than undergrounding from 2020-2026. PG&E's continued "preference" for undergrounding is unwarranted from a risk reduction and cost perspective.
- PG&E has done a very poor job of appropriately targeting its SH undergrounding program to the highest risk locations, as determined by the risk model PG&E used to scope projects from 2020-2026.
    - Whether a failure of PG&E or difficulty in scoping high-risk miles, the cost-effectiveness of undergrounding has likely been far worse than PG&E's modelling has suggested.
    - For example, of the 584 underground miles that utilized version 2 of PG&E's wildfire distribution risk model (WDRM), just 75 were in the top 10 percent of risk, while 371 (64 percent) were in the <u>bottom 50 percent</u> of risk. The highest 10 percent risk tranche in this model consists of 600 miles, more than the sum of miles scoped using this model.
- Based on its own forecast PG&E will fall short of its TY 2023 GRC approved level of deployment by 191 miles, equivalent to over $572 million (assuming $3 million per mile unit costs).
    - This is largely because PG&E has inappropriately included Fire Rebuild (FRRB) miles in its count of SH miles. TY 2023 GRC funding was intended to deliver 1,230 miles of undergrounding, which are not expected to be completed by the end of 2026.
- Undergrounding projects take many years to accomplish and therefore do not utilize updated risk models.
    - Most of PG&E's deployment to-date has relied on the second version of PG&E's risk model, developed around 2021.
    - For this GRC, despite the fact that it was filed in 2025, just 127 of 307 TY 2027 miles (41 percent) are expected to use the most current version of the risk model (WDRMv4).
    - Rather than rush capital expenditures out the door, PG&E could take a more deliberate approach to its undergrounding program, by ensuring only very high-risk locations are targeted, where feasible. If not feasible, other programs like overhead hardening should be prioritized. Instead,

ratepayers bear the consequences of sub-optimal deployment while rates have been driven to nearly the highest in the country.

- PG&E's overhead hardening forecast uses slightly inflated unit costs. The Commission should adopt the four-year weighted average unit cost of this program from 2021-2024 as the basis of a more accurate forecast for this GRC..
- Batteries and other backup power solutions are significantly more affordable options to mitigate PSPS and EPSS risk compared with undergrounding. To ensure optimal program design that is in the ratepayer interest,
    - PG&E's CBI proposal for utility-owned batteries is unnecessary and should be rejected.
    - The Commission should continue the Residential Storage Initiative (RSI) program with a lower rebate and budget cap to support battery deployment in the High Fire Threat District (HFTD) to mitigate PSPS and EPSS risk.

The cost implications of TURN's recommendations are provided in the Table below.

Table 1. TURN vs. PG&E Forecast Costs ($ Thousands)[2]

PG&E	2023-2026	2027	2028	2029	2030
System Hardening - Undergrounding	$216,365	$650,873	$64,765		
System Hardening - Overhead		$197,282	$197,487	$204,130	$264,630
Residential Storage Initiative (Res Batteries)		$41,200	$6,190	$6,213	$5,710
BTM Capital Battery Program		$13,000	$26,000	$26,000	$26,000

TURN	2023-2026	2027	2028	2029	2030
System Hardening - Undergrounding	$0	$0	$0		
System Hardening - Overhead		$184,437	$184,224	$190,855	$2~~54,588~~46,858
Residential Storage Initiative (Res Batteries)		$28,760	$16,611	$16,623	$16,365
BTM Capital Battery Program		$0	$0	$0	$0

TURN-PG&E	2023-2026	2027	2028	2029	2030
System Hardening - Undergrounding	-$216,365	-$650,873	-$64,765	$0	$0
System Hardening - Overhead		-$12,845	-$13,263	-$13,274	-$17~~0~~,77~~04~~2
Residential Storage Initiative (Res Batteries)		-$12,440	$10,421	$10,410	$10,655
BTM Capital Battery Program		-$13,000	-$26,000	-$26,000	-$26,000

[2] Undergrounding costs are incurred from 2023-2028 as part of the TY 2027 forecast. This table shows the total 2023-2026 costs in a single column for simplicity; the annual totals for PG&E's cost proposal are in PG&E's Workpaper Table 7-11, row 36.

II. SYSTEM HARDENING — UNDERGROUNDING

PG&E proposes 307 miles of undergrounding for TY 2027 at a cost of $932.0 million incurred over the period from 2023-2028, due to the multiple years that undergrounding projects require.[3] Undergrounding is PG&E's "preferred" solution for wildfire mitigation "in the highest risk areas."[4] This is because PG&E states undergrounding provides "(1) near permanent ignition risk reduction from overhead electric distribution equipment" and "(2) avoid[s] customer reliability impacts from deploying PSPS and EPSS to mitigate wildfire risk on overhead lines."[5]

PG&E's undergrounding proposal is based on a "continuation of the mileage and unit cost approved in the 2023 GRC Decision,"[6] where 307 miles is the average across the four years of 2023 GRC-approved miles. Importantly, PG&E includes no forecast for 2028-2030 undergrounding miles and costs because the 2027 amount is considered a "bridge" to PG&E's Electric Undergrounding Plan (EUP) application where the utility will provide its forecast for these years.[7] PG&E also proposes an "annual extension to continue its Undergrounding Program work given the uncertain timing for EUP approval;"[8] this aspect of PG&E's proposal is not addressed in this testimony.

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[3] Workpaper Table 7-11.

[4] PG&E-4, p. 7-24.

[5] PG&E-4, p. 7-23. Note all citations to PG&E-4 in this testimony refer to the errata version submitted November 10, 2025.

[6] PG&E-4, p. 7-32.

[7] PG&E-4, p. 7-25.

[8] PG&E-4, p. 7-24.

A. PG&E's TY 2027 Undergrounding Forecast is Inadequately Supported

PG&E's undergrounding proposal for nearly $1 billion of capital expenditures for undergrounding in 2027 is inadequately supported. It is based primarily on the average number of miles approved in the previous GRC. Unlike maintenance, vegetation management, or other regulatory compliance programs, SH undergrounding represents elective work that warrants continual, ongoing scrutiny. The TY 2023 GRC was the first large-scale undergrounding proposal from PG&E, and the fact that SH undergrounding was approved in the TY 2023 GRC decision does not by itself warrant any additional funding in this GRC.

Significantly, PG&E has denied intervenors the opportunity to assess its hardening strategy for the entire four-year GRC period. As TURN's testimony has demonstrated in the past, there are often significantly more cost-effective and affordable ways to reduce risk.[9] Indeed, the CPUC stated in response to an Executive Order promoting electric rate affordability that utilities should "Identify cost-reduction measures by integrating wildfire mitigation strategies into the existing General Rate Case process."[10] A one year forecast is not sufficient to accomplish sufficient analysis of PG&E's SH proposals and available alternatives, particularly when it is clear that additional, substantial costs for this program will be incurred in the post-test years, 2028-2030. Ratepayers should not bear the consequences of PG&E's incomplete proposal.

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[9] For example, see TURN's testimony in A.21-06-021, *Testimony of Eric Borden Addressing Pacific Gas and Electric's Test Year 2023 General Rate Case Wildfire Mitigation Measures*, June 13, 2022; A.23-05-010, *Direct Testimony of Eric Borden addressing Southern California Edison's Test Year 2025 General Rate Case Wildfire Grid Hardening Investments,* February 29, 2024.

[10] CPUC, *CPUC Response to Executive Order N-5-24,* February 18, 2025, online: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/reports/cpuc-response-to-executive-order-n-5-24.pdf.

What we do know about the TY 2027 undergrounding forecast is that it will achieve very little risk reduction for the substantial cost imposed. Once PSPS and EPSS are considered, undergrounding in 2027 is expected to reduce risk by less than 1 percent.[11] Meanwhile, PG&E will rely primarily on PSPS and EPSS to mitigate wildfire risk across its service territory. Further, based on a historical analysis of PG&E's undergrounding expenditures to-date, the Commission has more information at its disposal regarding serious shortcomings of PG&E's undergrounding program that were not previously clear or could only be theoretically explored, which I discuss in the next section. If the massive expenditures approved in the TY 2023 GRC was PG&E's chance to prove that its undergrounding program is worth the enormous burden it has put on ratepayers, PG&E has failed the test.

B. PG&E's Historical Performance Deploying Undergrounding Indicates Prioritization of this Mitigation is Not in the Ratepayer Interest

In the TY 2023 GRC, there was virtually no historic performance data to leverage when evaluating PG&E's large-scale proposal for wildfire risk-related undergrounding. That is not the case here. Below I demonstrate that PG&E has not targeted undergrounding to the highest risk areas based on the models it uses to assess risk, overhead hardening is generally a superior alternative to underground hardening based on historical cost and performance, PG&E is unlikely to meet the TY 2023 GRC mileage requirement, and the considerable time lag of undergrounding projects from scoping to completion does not allow PG&E to utilize contemporaneous (and hopefully improved) risk models.

[11] EO-WLDFR-4b_Bow Tie Data (HFRA)_Errata. Tab "Risk Reduction by Program."

1. PG&E Has Not Targeted the Highest Risk Locations with Undergrounding Projects

PG&E has done an extremely poor job of targeting the highest risk locations *according to the risk model it scopes projects with.* TURN raised this likelihood in the TY 2023 GRC, given the size and scope of PG&E's proposal. As summarized by the Commission "TURN raises a related concern stating that, should PG&E fall behind schedule, PG&E may focus its undergrounding where it can expedite construction rather than in areas most beneficial for risk reductions purposes."[12] PG&E has developed four Wildfire Distribution Risk Models (WDRM) from version 2 (v2) to version 4 (v4). WDRMv2 was developed in 2021, WDRMv3 in 2022, and WDRMv4 in 2024.[13]

PG&E's inability to target the highest risk miles according to its own risk models could be because of limitations to how undergrounding projects are scoped, PG&E's desire to meet mileage targets rather than maximize risk reduction, or likely some combination of the two. Either way, it reflects yet another severe limitation of PG&E's undergrounding program. The figure below shows miles completed using WDRMv2 to scope projects, with the far-left miles of the figure showing the top 10 percent of risk according to this model, and the far right the bottom 10 percent of risk according to this model.

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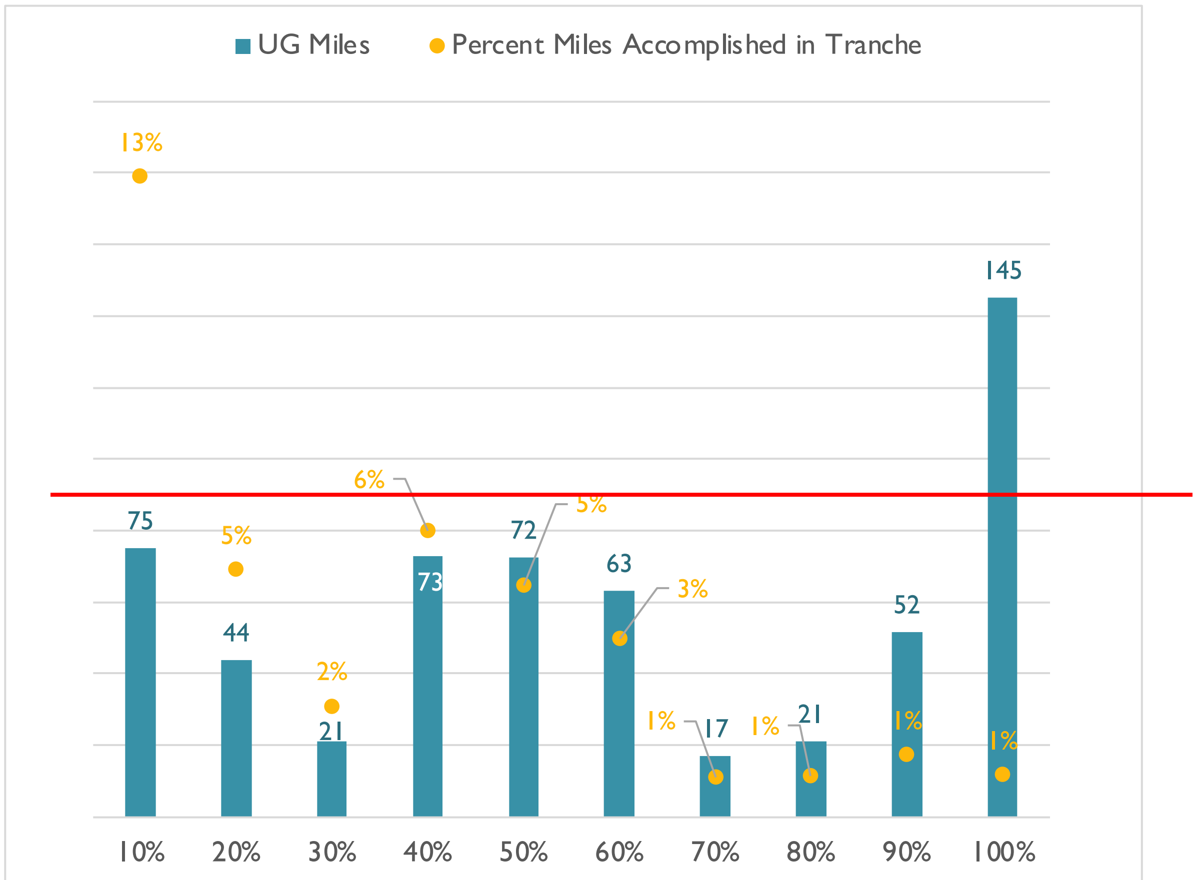
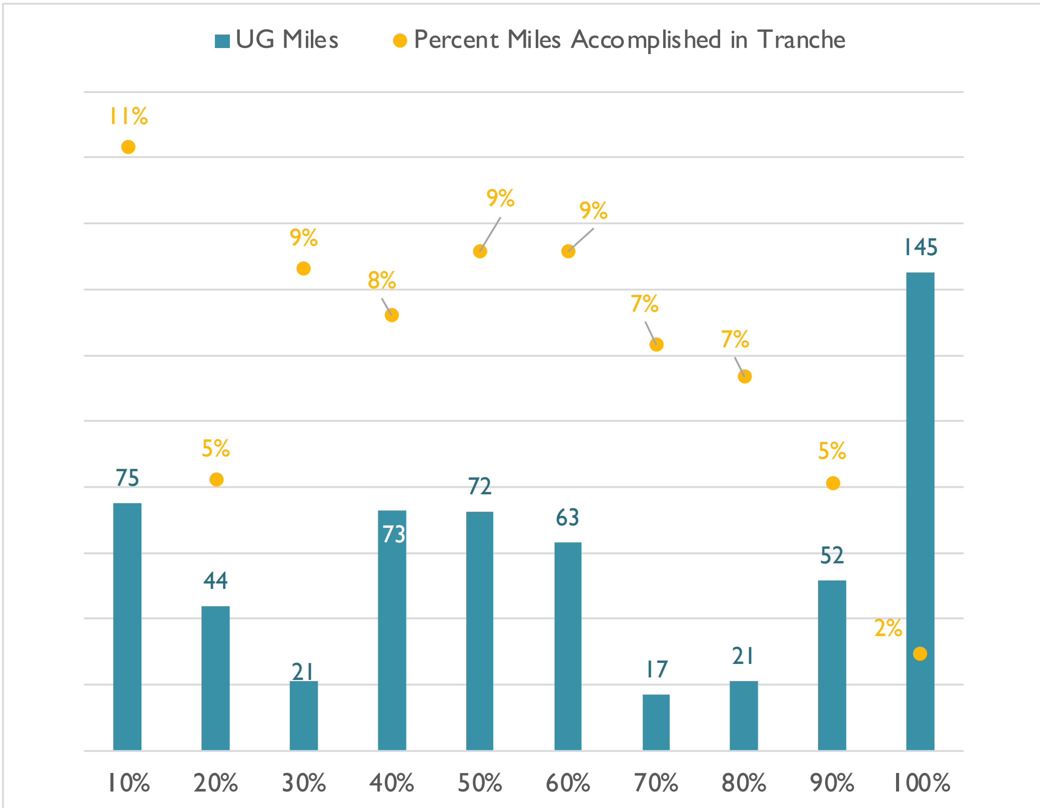
[12] TY 2023 GRC Decision, pp. 285-286.

[13] TURN-93, question 1(e).

Figure 1. WDRMv2 UG Miles Completed from Highest to Lowest Risk

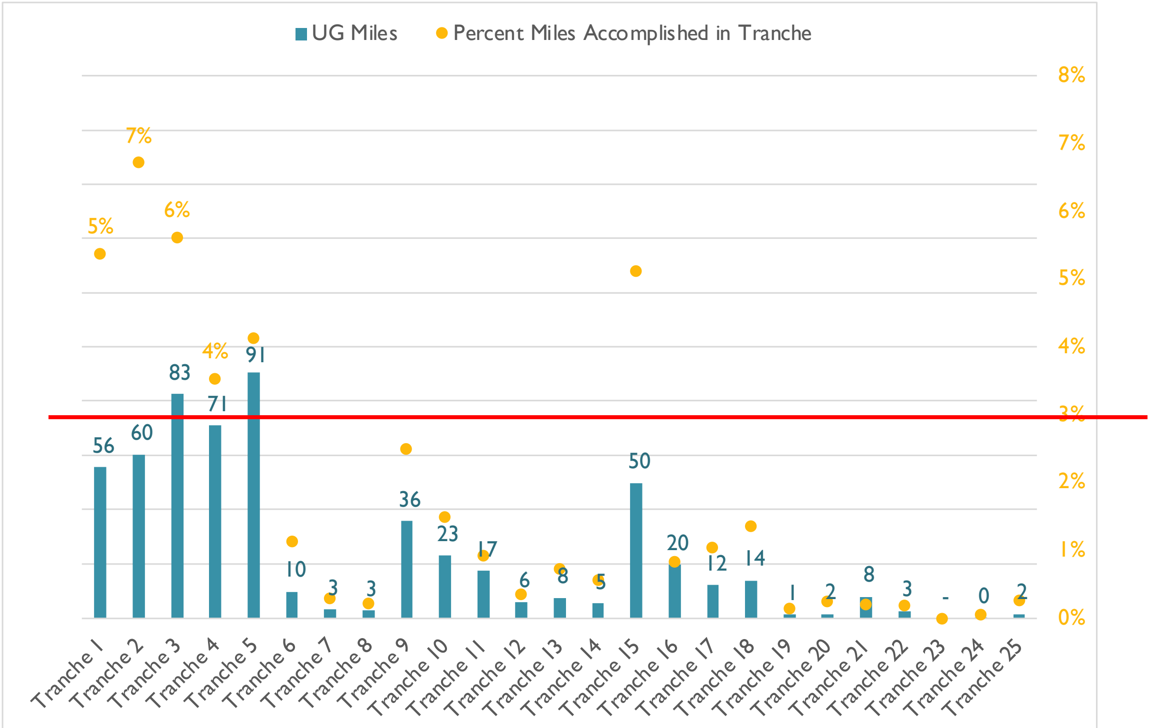


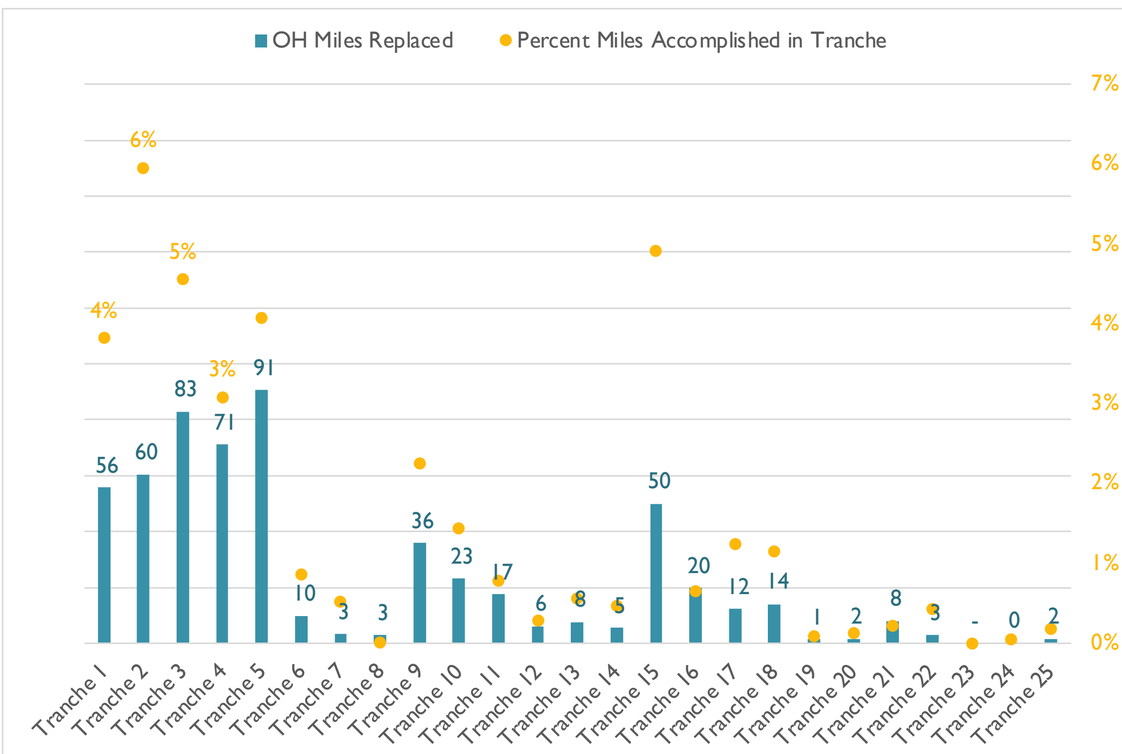


Source: TURN-47, question 8, attachment 1 (circuit segments by applicable risk model); TURN-93, question 1, supplement 1, attachment 1 (circuit segment by risk score). Adopts PG&E's methodology for calculating percent miles in tranche discussed in TURN-162, question 4(b).

Next, the following figure shows these results by risk tranches as defined by PG&E, with tranche 1 being the highest risk, tranche 2 the next highest, etc.

Figure 2. WDRMv2 UG Miles Completed from Highest to Lowest PG&E Risk Tranche



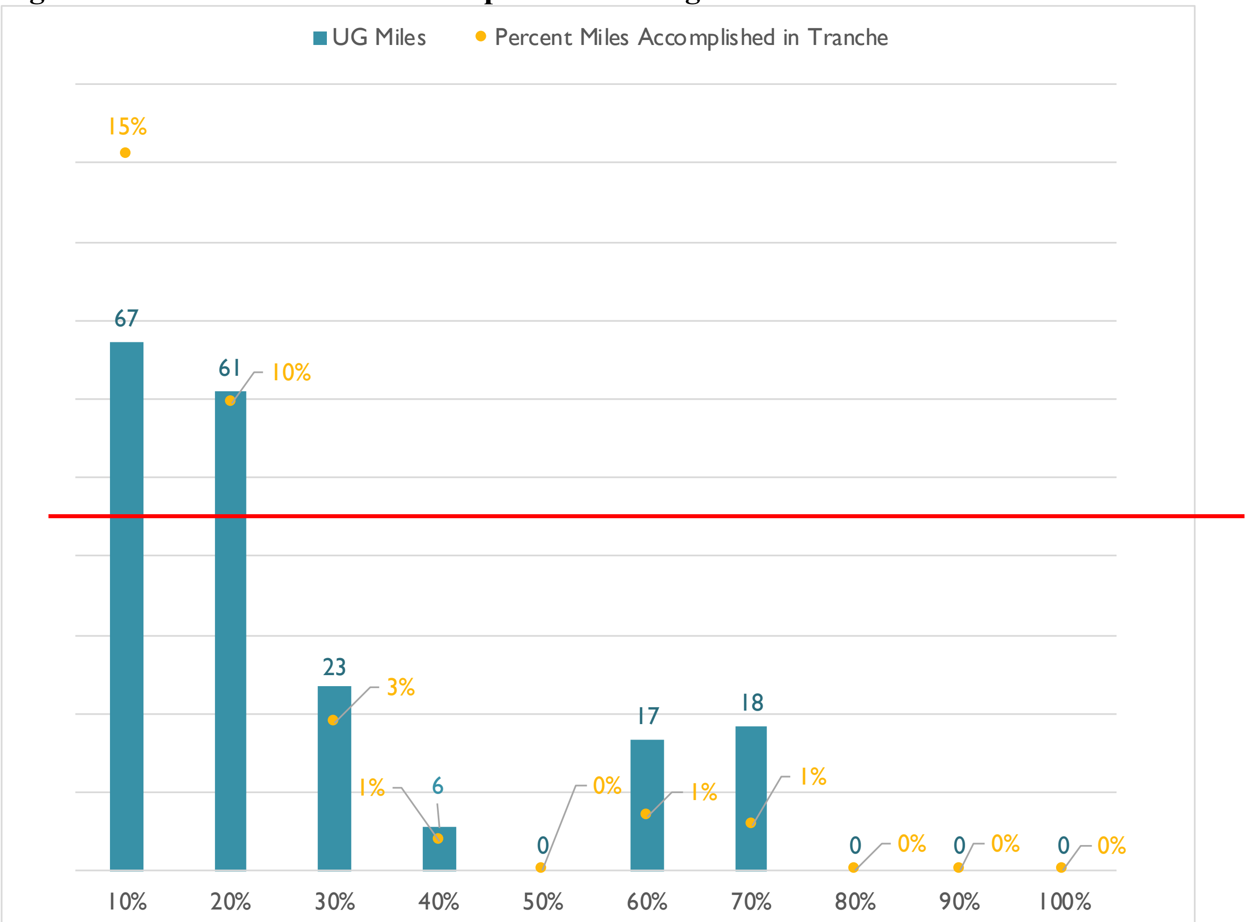


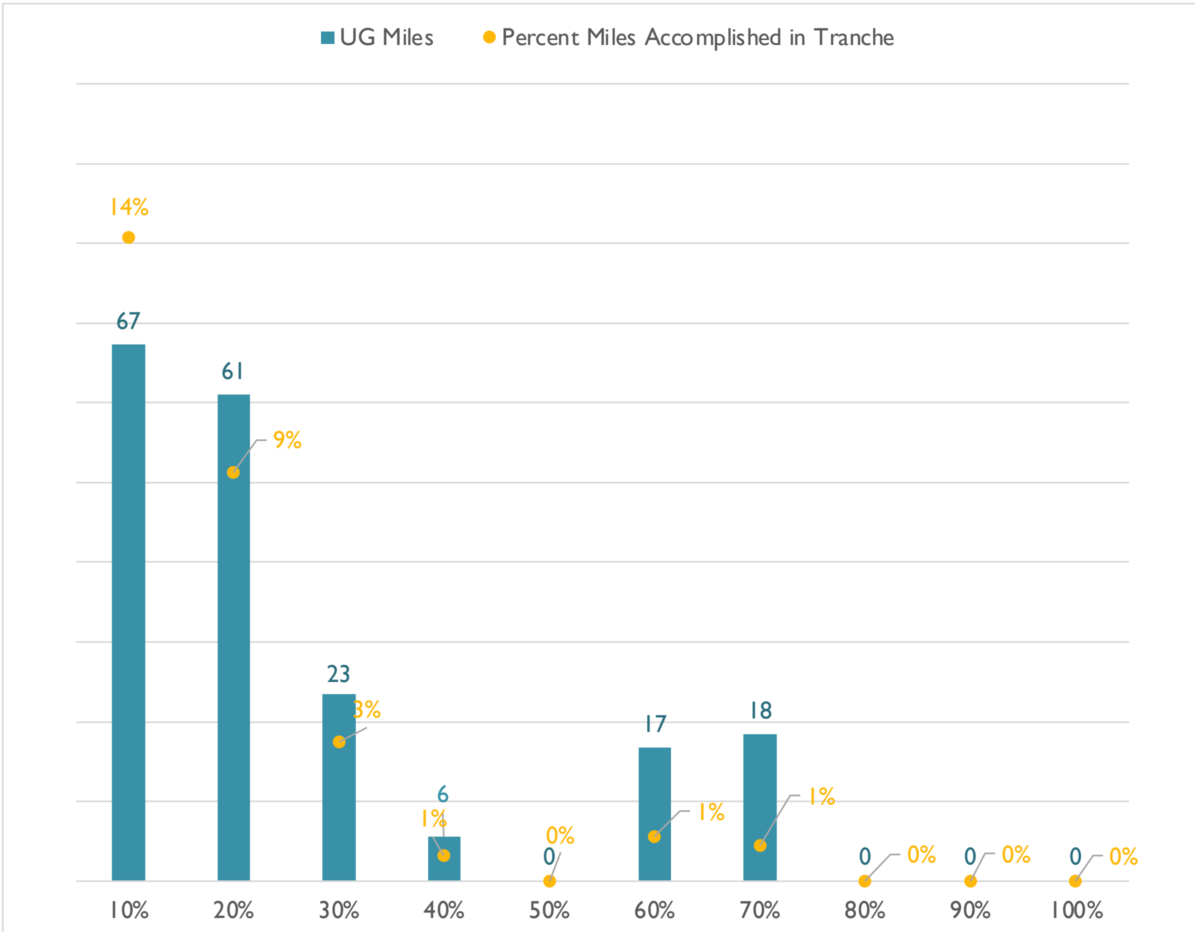
Source: TURN-47, question 8, attachment 1 (circuit segments by applicable risk model); TURN-93, question 1, supplement 1, attachment 1 (circuit segment by risk score). Adopts PG&E's methodology for calculating percent miles in tranche discussed in TURN-162, question 4(b).

Of the 584 miles completed using WDRMv2 to scope projects, an astounding 64 percent were completed in the bottom 50 percent of risk; 25 percent in the bottom 10 percent! Further the figure shows that PG&E undergrounded only ~~13~~ 11 percent of the miles ~~(75) the~~ in the top 10 percent of risk, which consists of a total of 600 miles. In other words, a program ~~that could be~~ targeted to the highest risk assets could have accomplished the entire 584 miles in the top 10 percent of risk.

Slightly improved results can be seen below for the 192 underground miles that have utilized WDRMv3. Here again, however, a purely risk-based program could have deployed all 192 miles within the top 10 percent of risk (which has 435 miles in total), rather than just ~~35~~ 14 percent.

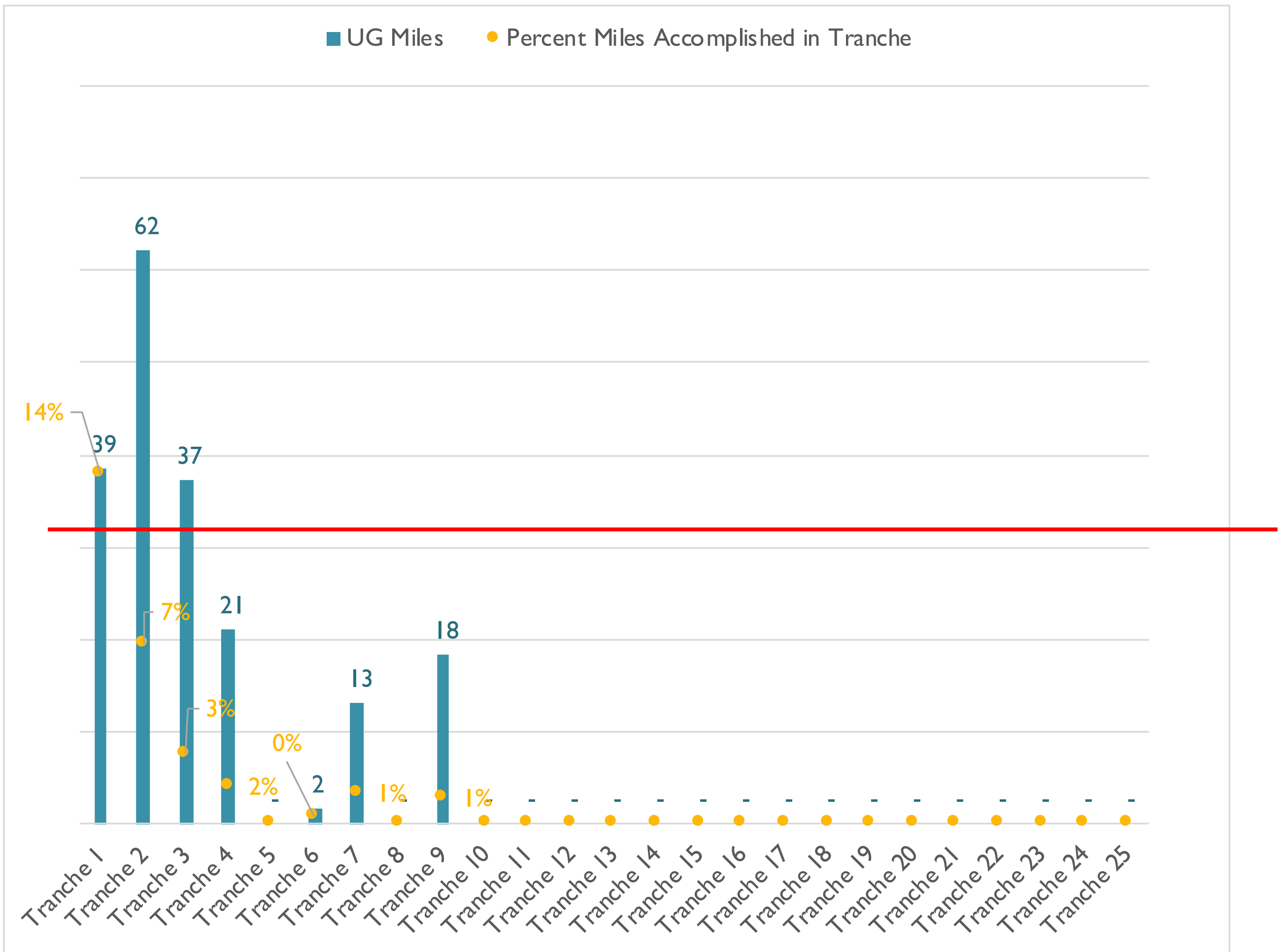
Figure 3. WDRMv3 UG Miles Completed from Highest to Lowest Risk

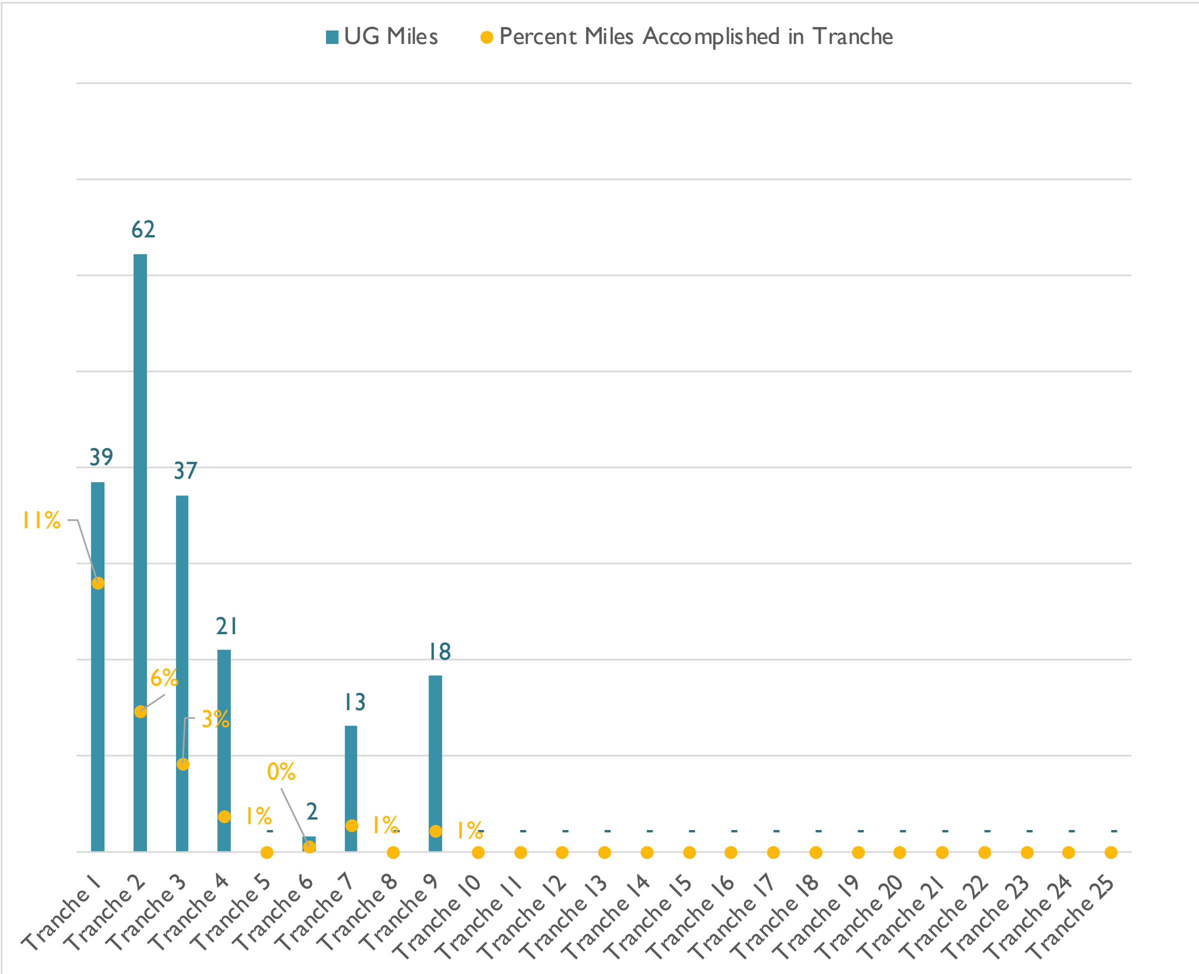




Source: TURN-47, question 8, attachment 1 (circuit segments by applicable risk model); TURN-93, question 1, supplement 1, attachment 1 (circuit segment by risk score). *Adopts PG&E's methodology for calculating percent miles in tranche discussed in TURN-162, question 4(b).*

Figure 4. WDRMv3 UG Miles Completed from Highest to Lowest PG&E Risk Tranche





Source: TURN-47, question 8, attachment 1 (circuit segments by applicable risk model); TURN-93, question 1, supplement 1, attachment 1 (circuit segment by risk score). Adopts PG&E's methodology for calculating percent miles in tranche discussed in TURN-162, question 4(b).

I expect that PG&E will counter this analysis with its own definition of risk. Rather than defining percentiles of risk according to risk *scores*, PG&E defines "risk" by a *"*count*"* of circuit segments when ranked from highest to lowest risk.[14] For example, if there are 1,000 circuit segments ranked from highest to lowest risk, the top 200 are the "top 20 percent" of risk, regardless of what the distribution of risk scores is among these circuits. In an extreme scenario

[14] I discussed this issue in A.22-12-009, *Prepared Testimony of Eric Borden, Addressing Pacific Gas and Electric's Wildfire Mitigation and Catastrophic Event Request,* September 8, 2023, pp. 17-21. This also references TURN's Opening Comments of The Utility Reform Network on Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan, May 26, 2023, pp. 25-29.

for illustrative purposes, the highest ranked circuit of 1,000 could contain 99 percent of the risk (e.g. 99 of 100 risk units) but PG&E would still count the top 200 as the "top 20 percent" of risk. Admittedly, "count" versus "sum" of risk sounds like a relatively banal difference, but it has allowed PG&E to falsely claim it is deploying on the "top 20 percent" of risk circuits regardless of the results of the risk models. For WDRMv2, PG&E's definition of the "top 20 percent" is actually the top <u>70 percent</u> of risk when calculated correctly; for WDRMv3 it is the top <u>97 percent</u> of risk when calculated correctly.[15] This shows how absurd and misleading PG&E's definition is compared with the actual measure of risk (risk units). The Commission should reject anything that relies on the PG&E circuit "count" definition of risk, as it appears to have been developed primarily to allow PG&E to deploy undergrounding to relatively low-risk circuits while claiming its programs prioritize risk reduction.

2. Overhead Hardening has Reduced More Risk for Less Cost Over More Miles than Undergrounding

For projects that consisted solely of undergrounding (as opposed to "hybrid") from 2020-2026 PG&E spent $1.9 billion to reduce wildfire risk by 4.5 percent.[16] Over this period, it undergrounded about 558.8 miles of overhead power lines, or around 2.2 percent of its HFTD.[17] Put another way, for each 1 percent of risk reduction achieved thus far with undergrounding,

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[15] TURN-93, question 1, supplement 1, attachment 1.

[16] Calculated from TURN-047, question 8, attachment 1. It was not possible with this data source to separate costs for overhead versus underground miles for "hybrid" projects, so I only include projects that are either solely underground or solely overhead hardening for this calculation. Further, not all projects included an estimate of overhead miles undergrounded, so I use PG&E's standard 1.25 underground to overhead conversion factor for these projects where this is the case. The 622 underground miles represent about 80 percent of underground miles in this data set (779).

[17] TURN-047, question 8, attachment 1. There are around 25,000 primary overhead miles in PG&E's High Threat Fire District (HFTD). PG&E 2026-2028 Wildfire Mitigation Plan, p. 156. Online: https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/2026-2028-base-wmp-vol-1-r3.pdf.

PG&E has spent $425 million. By contrast, over the same time period, PG&E's overhead hardening program has reduced more risk (7.2 percent) over more miles (980.7) for less cost ($1.0 billion).[18] For each percentage of risk reduction for the overhead hardening program, PG&E has spent around $144 million. So, to achieve the same amount of risk reduction, undergrounding comes at a 295 percent cost premium to overhead hardening (based on recent spending and PG&E's methodology to determine risk reduction).

This is due to two primary factors. First, overhead hardening costs significantly less than undergrounding on a per mile basis — around $930,000 per mile on a weighted average basis for overhead hardening (see Section III) versus $4 million per overhead mile on a weighted average basis from 2023-2026.[19] Second, overhead hardening has a high mitigation effectiveness on its own, according to PG&E 67 percent.[20]

Indeed, according to PG&E's own circuit-specific cost-effectiveness analysis for potential miles to underground in this GRC, 308 of the 473 miles analyzed show that overhead hardening has higher cost-effectiveness than undergrounding.[21] For 159 of these miles, overhead hardening (alone) was more cost-effective than "hybrid" projects, and for all projects is more affordable

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[18] Analysis from data provided in TURN-47, Question 8, Attachment 1. I exclude "hybrid" projects for the reasons stated in the footnote above. The 981 miles represents 95 percent of overhead hardening miles in this data set (a total of 1,037).

[19] TURN-93, question 2, Attachment 1. The Commission must ensure it compares unit costs of overhead and underground hardening on dollars per overhead mile basis. PG&E almost never presents undergrounding unit costs this way, opting instead for dollars per underground mile.

[20] PG&E 2026-2028 Wildfire Mitigation Plan, p. 128, Table PG&E-6.1 3-1. Online: https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/2026-2028-base-wmp-vol-1-r3.pdf.

[21] TURN-48, question 5, attachment 1.

than undergrounding (because it costs significantly less per mile).[22] Since PG&E uses a convoluted "decision tree" process that is biased towards undergrounding, it still chooses to underground many of these circuits. or large portions of them, undermining cost-effectiveness and affordability goals that should guide utility programs, particularly ones that effect affordability as much as SH undergrounding.[23]

PG&E's primary counter arguments to this appear to be 1) undergrounding has a higher mitigation effectiveness than overhead hardening, 98 percent[24] versus 67 percent[25] for covered conductor; and 2) undergrounding mitigates PSPS and EPSS risk which covered conductor does not.

First, PG&E's argument regarding mitigation effectiveness advantages are moot from a wildfire risk perspective as demonstrated in PG&E's 2026-2028 WMP, which acknowledges that ignition risk reduction comparable to undergrounding can be achieved by overhead hardening combined with other mitigations. The WMP recognizes that the combination of covered conductor, PSPS, and EPSS is <u>97% effective in reducing ignition risk</u>, which is nearly identical to primary line undergrounding's ~98% effectiveness value.[26] Over time, other technologies, such as Rapid

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[22] TURN-48, question 5, attachment 1.

[23] TURN's analysis of PG&E's decision tree can be found in TURN's Opening Comments on PG&E's 2026-2028 Base WMP, Section II, pp. 2-5, attached to this testimony.

[24] PG&E-4, p. 7-24.

[25] PG&E 2026-2028 Wildfire Mitigation Plan, p. 128, Table PG&E-6.1 3-1. Online: https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/2026-2028-base-wmp-vol-1-r3.pdf.

[26] PG&E 2026-2028 Base WMP (R0), Table 6.1.3-1, p. 128.

Earth Fault Current Limiter (REFCL)[27] technology, have the potential to make overhead hardening even more effective at reducing ignition risk.[28]

Second, while it is true that undergrounding reduces PSPS/EPSS risk more than overhead hardening, most other ways to address this risk is more affordable than undergrounding. Given its expense, undergrounding should be viewed first and foremost as a *wildfire* mitigation, with a secondary benefit of PSPS/EPSS risk reduction. As an example, undergrounding all 25,000 miles of HFTD primary lines would cost around <u>$100 billion</u> at current unit costs (around $4 million per overhead mile), while purchasing a battery for all 505,000 HFTD residential customers would cost around <u>$10.1 billion</u>.[29] As another example, PG&E's current list of circuits planned for undergrounding have 7,390 potential PSPS customers (with varying levels of risk).[30] PG&E's proposal for $932 million for undergrounding thus costs over $126,000 per customer with PSPS risk, compared with $10,000 - $20,000 for a battery (depending on the size) or $500 for a generator / small battery for critical loads.[31] From a shutoff risk perspective, undergrounding is very obviously unaffordable and unnecessary to mitigate PSPS and EPSS outage risk. Lastly on this point, I note that PG&E currently estimates around 11,358 miles of the HFTD do not have

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[27] PG&E 2026-2028 WMP, p. 336.

[28] See TURN's Opening Comments on PG&E's 2026-2028 Base WMP, Section III, p. 6.

[29] TURN-79, question 10, attachment 1. I assume $20,000 per battery which is PG&E's assumption for its battery programs.

[30] TURN-79, question 2, attachment 1. There are slightly more EPSS eligible customers, 8,805, many of which overlaps with the PSPS count. This yields a similar result of $106,000 per EPSS customer.

[31] PG&E Generator and Battery Rebate program provides a $300 rebate for small generators, which based on a random sampling can cost just $500. PG&E, *Generator and battery rebates*, https://www.pge.com/en/outages-and-safety/outage-preparedness-and-support/general-outage-resources/generator-and-battery-rebate-program.html.

PSPS risk.[32] Based on the broad criteria PG&E uses for undergrounding, it is highly likely PG&E will underground some or many of these miles, providing no PSPS risk reduction.

3. PG&E Will Fall Short of its TY 2023 GRC Undergrounding Mileage Requirement

The Commission must also consider PG&E's performance with regard to its commitments in the TY 2023 GRC. There, the Commission required PG&E to complete 1,230 miles of undergrounding, with additional accountability and tracking through a System Hardening Accountability Report (SHAR).[33] In this reporting, PG&E has inappropriately included miles accomplished as part of the utility's "Fire Rebuild" (FRRB) program, which re-builds infrastructure after a wildfire has destroyed utility equipment, and is separate from the SH program. Subtracting FRRB miles from the utility's recorded and forecast figures means PG&E will fall around 191 miles short of the Commission's requirement, equivalent to over $572 million assuming $3 million per mile unit costs. However, it may be more than this figure. PG&E did not reach its 2025 forecast. The same issue applies to 2026. TURN has supplemented this testimony to incorporate recorded 2025 undergrounding mileage data, shown below.

[32] TURN-93, question 6(c).

[33] TY 2023 GRC Decision, p. 862.

Table 2. System Hardening and FRRB Miles Recorded/Forecast (2023-2026)

Year	Miles Recorded/Forecast	FRRB Miles
2023	285	58
2024	214	27
2025	*306*	*11*
2026 (Forecast)	*333*	*2*
Total	1,175	102
Total Less FRRB	***1,039***	
Miles Not Completed per TY 2023 GRC Decision	***191***	

Source/Note: TURN-93, question 1, attachment 1, which provides PG&E's 2024 Annual System Hardening Accountability Report. The Commission authorized 1,230 miles. PG&E-16, Rebuttal Testimony, 2023-2027 GRC System Hardening Work Plan, tab "SHUG Workplan 3.11.26." PG&E's rebuttal testimony states that it now forecasts 400 miles for 2026. It is not clear to me that this forecast is any more accurate than its previous forecast. If it is true, this would result in 124 miles not completed per the TY 2023 GRC decision, equivalent to $371 million assuming $3 million per mile unit costs. I note that PG&E's 2024 SHAR forecasted 343.5 underground miles, and PG&E proposed 770 more miles in the TY 2023 GRC from 2023-2026 than the 1,230 approved (see below).

4. FRRB Miles Do Not "Count" Towards System Hardening Mile Targets Established by the Commission

As stated above, PG&E has inappropriately included FRRB miles as part of its count of SH miles. In the TY 2023 GRC, the Commission rejected PG&E's eventual forecast of 2,000 miles for a "hybrid" scenario that included 1,230 miles of undergrounding. Given that PG&E's level of undergrounding proposed was unprecedented, the Commission stated it was "skeptical of PG&E's proposed pace, and will scrutinize PG&E's progress over time."[34] The Commission's approval of 1,230 miles refers only to system hardening miles, stating "This decision authorizes an historic 1,230 miles of undergrounding for PG&E to implement[…]. PG&E is directed to invest approximately $4.723 billion in system hardening, including undergrounding and

[34] TY 2023 GRC Decision, pp. 278-279.

installing covered conductor."[35] The 1,230 miles of undergrounding in Section 4.3 of the TY 2023 GRC Decision is titled "Wildfire System Hardening."[36] The only place in the Decision discussing fire rebuild costs states explicitly that these costs were not approved as part of TY 2023 GRC funding. In Findings of Fact 173 through 175, the Commission states in part:

> 173. PG&E's requests pertaining to the rebuilding costs after the 2018 Camp Fire, as reflected in PG&E's Community Rebuild Program (including the Town of Paradise and surrounding area and the Butte Wildfire rebuild) and recorded in PG&E Ex-04 at WP Table 23-13 **should not be adopted**.
>
> 174. PG&E may seek recovery of the costs presented in PG&E Ex-04 at WP Table 23-13 in a CEMA application and, as a result,
>
> 175. An expense forecast of $0 and capital expenditures of $0 for all the expense and capital presented in this proceeding (2018-2026) PG&E Ex-04 at WP Table 23-13 should be adopted.[37]

Furthermore, the Commission believed, based on PG&E's assertions, that the utility would target the highest wildfire risk locations in its HFTD. It stated "[b]y approving 1,230 undergrounding miles, this hybrid scenario will allow PG&E to underground the highest risk 984 overhead miles on its system."[38] Fire Rebuild work occurs wherever a wildfire has burned equipment, not necessarily "the highest risk locations" determined by PG&E's risk modeling.

Despite the Commission's very clear decision for the TY 2023 GRC, PG&E claims that its "policy of prioritizing fire rebuild work over proactive system hardening work has been in place since PG&E began developing its system hardening program and implementing system

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[35] TY 2023 GRC Decision, pp. 2-3.

[36] TY 2023 GRC Decision Section 4.3.4, Finding of Fact number 108, p. 800.

[37] Emphasis added. TY 2023 GRC Decision, p. 878.

[38] TY 2023 GRC Decision, p. 272.

hardening work in 2018."[39] When asked to produce references to Commission decisions that support PG&E's decision to include FRRB miles as part of SH, PG&E responded:

> The scope of system hardening work, including HFTD fire rebuild, was described in PG&E's 2023 GRC testimony and workpapers and was detailed in the 2023 Wildfire Mitigation Plan and 2026 Wildfire Mitigation Plan [footnotes omitted]. PG&E's system hardening program was approved in the 2023 GRC Decision. The 2023 WMP was approved by Energy Safety and the 2026 WMP currently has a draft approval by Energy Safety.[40]

PG&E's response does not actually point to a Commission Decision or any language therein to support its position that FRRB and SH miles are the same. PG&E's only argument relevant to GRC spending is its reference to workpapers included in the case. The Commission did not address this aspect of PG&E's proposal.

PG&E will fall short of Commission expectations from the TY 2023 GRC Decision, which to be clear were below PG&E's own forecast. Therefore, an estimate of miles previously approved should count towards TY 2027 funding of undergrounding; no further funding from ratepayers of this work should be required. At TY 2023 GRC average unit costs authorized of around $3 million per mile, this equates to around $572 million.

5. Undergrounding is Extremely Slow to Deploy and therefore Cannot Utilize Improved Risk Models Until Many Years Later

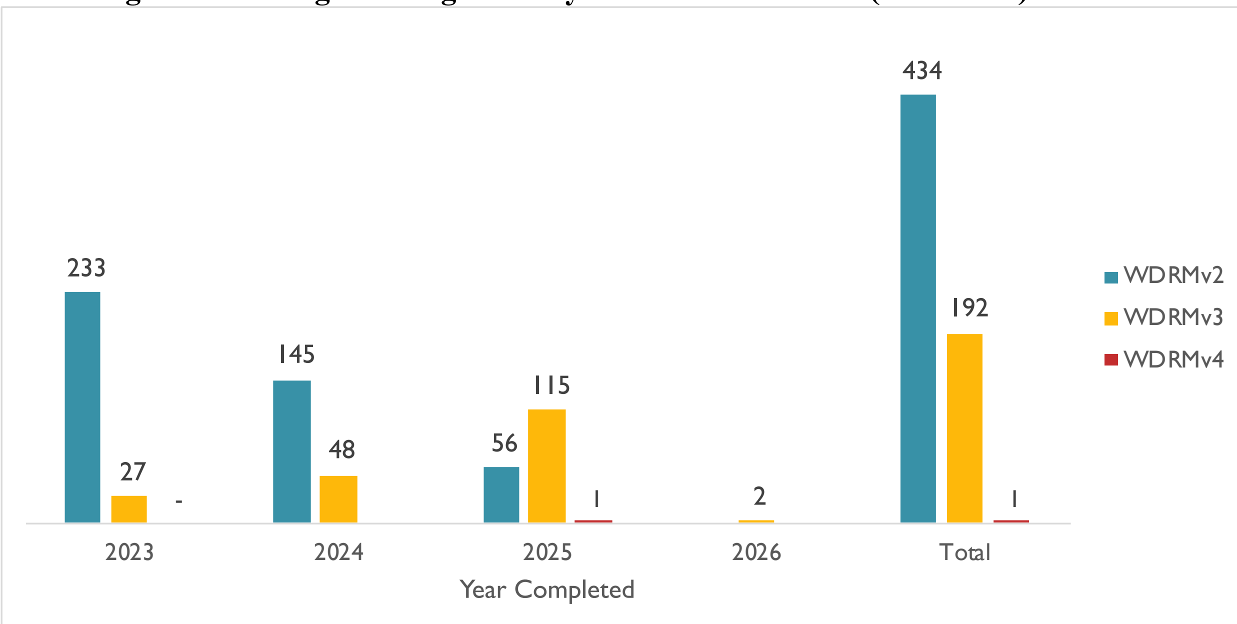
Another striking aspect of PG&E's undergrounding performance is the degree to which projects coming online in recent years rely on outdated risk modeling. This means that PG&E is unable to rely on its latest assessments of risk for virtually any of the projects that it has undergrounded. Of the 627 miles completed from 2023 to 2026, over two-thirds (69 percent) utilized just the second

[39] TURN-48, question 6.

[40] TURN-93, question 5(a). Workpapers cited from the TY 2023 GRC are Exhibit PG&E-4, WP 4-92 to 4-94; Exhibit PG&E-17, p. 4.3-20.

version of PG&E's risk model, due to the fact that undergrounding scoping, site preparation, and other issues take so long.[41]

Figure 5. Undergrounding Miles by Risk Model Version (2023-2026)



Source/Note: TURN-047, question 8, attachment 1. Note the mileage here differs from below because this figure examines 2023-2026 while the figures below examine 2020-2026.

So while continual improvement in PG&E's risk modeling approach has been a key focus of the CPUC and OEIS, it has hardly yielded better project selection in terms of targeting what PG&E believes are the highest risk locations for undergrounding projects. Indeed, for the 2027 forecast in this GRC, 180 of the 307 miles would use previous risk models (v2 and v3),[42] despite the fact that the Commission is ostensibly deciding on expenditures for 2027.

Adding to the concern that this has likely led to sub-optimal project selection is the fact that the results of these models have been so inconsistent. As OEIS noted when comparing the

[41] PG&E-4, pp. 7-25-7-28.

[42] CalAdvocates_190, question 5, attachment 1, Confidential.

WDRMv2 and WDRMv3 risk models, "no observable correlation between the V2 and V3 risk scores can be seen."[43] To be clear, had PG&E and the Commission opted for a more measured approach to undergrounding this would be less of a concern. As the Commission noted in the TY 2023 GRC "No utility, including PG&E, has ever made a proposal of this magnitude for undergrounding its distribution assets."[44] But Instead, PG&E's clear priority has been capital expenditures over safety impacts. As the utility has relied on other less capital-intensive programs to *actually* reduce risk, it is happy to pour billions of dollars into projects even when it cannot be confident these ratepayer dollars reduce the greatest amount of risk for dollars spent.

C. Conclusions and Recommendations

The analysis above demonstrates that PG&E's undergrounding proposal is inadequately supported — on this premise alone, it should be rejected. The proposal is based almost entirely on the average miles approved in the previous GRC. Further, PG&E did not include a four-year forecast for undergrounding, which limits the Commission's ability to evaluate the program holistically in terms of both risk reduction and affordability. Indeed, I suspect billions of dollars for undergrounding from 2028-2030 will be proposed in PG&E's Electric Undergrounding Plan (EUP). If the Commission cannot holistically evaluate affordability, it must err on the side of the caution particularly given PG&E's record of proposing massive undergrounding expenditures.

Notwithstanding, TURN demonstrates that PG&E's deployment of the undergrounding program to-date has largely not been in the ratepayer interest and certainly does not support a "preference" for undergrounding. The previous sections demonstrate that:

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[43] OEIS Final Decision on PG&E's WMP 2022 Update, p. 64, online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/spd-9-resolution.pdf.

[44] TY 2023 GRC Decision, p. 280.

- It is inadequately supported.
    - The proposal is based primarily on the average number of miles adopted in the previous Test Year (TY) 2023 General Rate Case (GRC) decision, as well as a flawed "decision tree" that is biased towards selection of undergrounding even if superior alternatives are available to mitigate risk and appropriately consider affordability.
    - It is impossible to assess PG&E's SH proposal holistically because the utility did not present a four-year forecast for undergrounding. Likely billions of dollars are missing from this GRC for undergrounding alone, leaving the Commission with inadequate information to assess the SH undergrounding forecast for TY 2027.
- In general, overhead hardening remains a superior alternative to undergrounding.
    - Combined with Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS), it reduces the same amount of wildfire risk as undergrounding and is more affordable.
    - Even without PSPS and EPSS, overhead hardening has reduced more risk at less cost over more miles than undergrounding from 2020-2026. PG&E's continued "preference" for undergrounding is unwarranted from a risk reduction and cost perspective.
- PG&E has done a very poor job of appropriately targeting its SH undergrounding program to the highest risk locations, as determined by the risk model PG&E used to scope projects from 2020-2026.
    - Whether a failure of PG&E or difficulty in scoping high-risk miles, the cost-effectiveness of undergrounding has likely been far worse than PG&E's modelling has suggested.
    - For example, of the 584 underground miles that utilized version 2 of PG&E's wildfire distribution risk model (WDRM), just 75 were in the top 10 percent of risk, while 371 (64 percent) were in the <u>bottom 50 percent</u> of risk. The highest 10 percent risk tranche in this model consists of 600 miles, more than the sum of miles scoped using this model.
- Based on its own forecast PG&E will fall short of its TY 2023 GRC approved level of deployment by 191 miles, equivalent to over $572 million (assuming $3 million per mile unit costs).
    - This is largely because PG&E has inappropriately included Fire Rebuild (FRRB) miles in its count of SH miles. TY 2023 GRC funding was intended to deliver 1,230 miles of undergrounding, which are not expected to be completed by the end of 2026.
- Undergrounding projects take many years to accomplish and therefore do not utilize updated risk models.

- Most of PG&E's deployment to-date has relied on the second version of PG&E's risk model, developed around 2021.
- For this GRC, despite the fact that it was filed in 2025, just 127 of 307 TY 2027 miles (41 percent) are expected to use the most current version of the risk model (WDRMv4).
- Rather than rush capital expenditures out the door, PG&E could take a more deliberate approach to its undergrounding program, by ensuring only very high-risk locations are targeted, where feasible. If not feasible, other programs like overhead hardening should be prioritized. Instead, ratepayers bear the consequences of sub-optimal deployment while rates have been driven to nearly the highest in the country.

To be clear, I do not oppose undergrounding for the highest risk circuits in PG&E's service territory. I believe a disciplined, targeted undergrounding program can reduce substantial risk in an affordable manner. However, PG&E's approach to undergrounding prioritizes capital spending over risk reduction and affordability. This has been made plainly obvious, and ratepayers should not continue to fund this program absent evidence that it is in the ratepayer interest.

I therefore find that the Commission should not allow any additional ratepayer funding for the underground system hardening program. Since PG&E will fall short of the TY 2023 GRC approved undergrounding mileage by around 191 miles, it can underground this number of miles in 2027 without additional ratepayer funding, ensuring a "bridge" to the EUP while mitigating risk. Further, PG&E's undergrounding program should be limited to the top 30 percent of risk (correctly defined, see above) given its historical performance of deploying to relatively low-risk circuits.[45]

[45] The top 30 percent of risk in PG&E's current risk model (WDRMv4) has 2,800 overhead miles (equivalent to 3,500 underground miles, using PG&E's standard conversion of 1.25). I do not believe this should be an overly restrictive requirement. For WDRMv2 and WDRMv3 this figure is 2,500 and 1,772,

III. UNIT COSTS OF OVERHEAD HARDENING

PG&E's proposal for overhead hardening is based in part on 2027 unit costs (dollars per overhead mile) of about $1.02 million per mile, plus transformer costs of about $20,000.[46] However, recent weighted average unit costs for 2021-2024 overhead hardening projects are around $930,000 per mile.[47] These costs have remained constant or on a downward trajectory over from 2021-204. Therefore, this weighted average is likely a more accurate estimate of TY 2027 overhead hardening unit costs.

Table 3. Overhead Hardening Unit Costs ($M)

Unit Costs	Miles	Costs ($M)	Average ($M)
2021	129.83	$ 132.67	$ 1.02
2022	299.63	$ 253.92	$ 0.85
2023	154.60	$ 156.27	$ 1.01
2024	104.09	$ 94.80	$ 0.91
Total / Weighted Average	**688.15**	**$ 637.66**	**$ 0.93**

Source: TURN-93, question 7, attachment 1.

To estimate total unit costs, I added estimated transformer costs of around $25,000 per mile to this estimate, producing unit costs of about $951,600 per mile.[48] The table below shows the

respectively. TURN-47, question 8, attachment 1 (circuit segments by applicable risk model); TURN-93, question 1, supplement 1, attachment 1 (circuit segment by risk score).

[46] PG&E Workpaper Table 7-12.

[47] I exclude 2020 unit costs because these costs are anomalous and not reflective of recent or future overhead hardening unit costs.

[48] This is the difference between PG&E's $1.02 M /mile cited unit cost and a calculation of unit cost using Workpaper Table 7-12 (2027 project costs line divided by miles).

difference between TURN and PG&E's total forecast cost estimates based on estimated unit cost adjustments in PG&E's risk modelling workpaper.[49]

Table 4. PG&E vs. TURN Overhead Hardening Cost ($ Thousands)

	2027	2028	2029	2030
PG&E	$ 197,282	$ 197,487	$ 204,130	$ 264,630
TURN	$ 184,437	$ 184,224	$ 190,855	$ ~~254,588~~246,858
TURN-PG&E	**$ (12,845)**	**$ (13,263)**	**$ (13,274)**	**$ (17~~0~~,7~~0~~742)**

Source/Note: TURN-143, supplemental response question 1, attachment 1, tab "TURN 1b." ~~s "PG&E Original Forecast" and "TURN 1b." I note that it was not possible to verify PG&E's calculations assuming TURN's unit cost due to a lack of transparency with inputs and calculations in this data request response. For purposes of this testimony I adopt PG&E's calculation.~~

IV. CUSTOMER BATTERY PROGRAMS

A. Overview

PG&E offers several back-up power programs to mitigate the effect of PSPS and EPSS outages. These include programs targeted at medically vulnerable customers, commercial and residential customers who receive a rebate after a generator or battery purchase, direct install programs, and a permanent battery storage rebate program (PBSR) which is PG&E's newest program.[50] From 2021-2024 PG&E spent $141.6 million on these programs, and expects to spend another $270.6 million from 2025-2030.[51] The focus of this testimony is a new proposal for a utility-owned battery program, the "Customer Battery Infrastructure" (CBI) program, for which PG&E

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[49] PG&E's Workpaper Table 7-12 and the risk modeling paper (which identifies unit costs) are inconsistent. Also, despite the fact that Workpaper Table 7-12 says PG&E uses "the GRC escalation rate," the total costs do not reflect this. The unit costs shown in PG&E-4, p. 7-22, Table 7-6 cannot be derived from the total costs.

[50] PG&E-4, Chapter 6, pp. 6-55 to 6-58.

[51] PG&E-4, Chapter 6, WP Table 6-5.

forecasts expenditures of $91 million from 2027-2030.[52]

Table 5. 2027-2030 Forecast Expenditures for CBI Program ($ Thousands)

	2027	2028	2029	2030
CBI Program	$ 13,000	$ 26,000	$ 26,000	$ 26,000

Under this program, PG&E will "own, install, maintain, and operate these batteries for the entire battery life, and remove them upon end-of-life. PG&E believes the program,

> significantly improves the cost-effectiveness of its existing permanent battery direct install program by enabling PG&E to layer on additional benefits, such as optimizing battery dispatch to benefit all customers through system or local peak load reduction. Other utilities have successfully implemented programs to install, own and operate behind-the-meter energy storage, most notably Vermont's Green Mountain Power (GMP), which currently has over 5,000 such batteries installed.[53]

PG&E believes this program is in the ratepayer interest because batteries are a "physical asset" that mitigate risk, participants will not have up-front barriers to adoption, and PG&E can improve cost-effectiveness by spreading costs to ratepayers over time and capturing system-wide and potential distribution grid benefits.[54]

B. PG&E Does Not Demonstrate a Utility-Owned Battery Program is in the Ratepayer Interest

1. Utility Ownership of Batteries is Not Necessary to Capture Ratepayer Value

Most or all of the "additional" value of utility ownership, except possibly distribution deferral (which PG&E does not commit to), do not actually require utility ownership of customer assets. Reducing peak load and otherwise optimizing market revenues can be accomplished by DER aggregators, or even PG&E, without asset ownership. As PG&E admits, there are active DER

[52] PG&E-4, p. 6-66, Table 6-24.

[53] PG&E-4, Chapter 6, p. 6-62.

[54] PG&E-4, Chapter 6, p. 6-62.

aggregators in its service territory capturing this value for customers.

> Some DER aggregations in PG&E's service territory are bid into CAISO by PG&E, while others are bid by third-parties. […] In general, DER aggregators are able sell Resource Adequacy (RA) to Load Serving Entities (LSEs), such as Investor-Owned Utilities or Community Choice Aggregators (CCAs), thus reducing their obligations to procure RA from other resources.[55]

Further, better marketing or even a requirement for customers to enroll in DR programs would allow a rebate program to capture additional ratepayer value. As recommended in a Self-Generation Incentive Program (SGIP) evaluation report, sub-optimal battery dispatch can be remedied by "encourage[ing] […] participants to enroll in DR or real-time retail rates to encourage increased dispatch during high GHG/demand hours."[56]

Further, I do not agree that capitalizing costs "improves cost-effectiveness" because it spreads costs over time. Capitalization increases costs because of additional carrying costs that must be paid by ratepayers over the longer-term. This has become all too apparent in recent years as PG&E's capital expenditures on wildfire mitigations have, in large part, caused rates to increase drastically. PG&E estimates a 10 percent premium for revenue requirements due to utility ownership of batteries on a present value basis, so instead of $90 million for this program, ratepayers will pay $100 million on a present value basis, and even more on a nominal basis over 10 years.[57]

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[55] TURN-79, question 13.

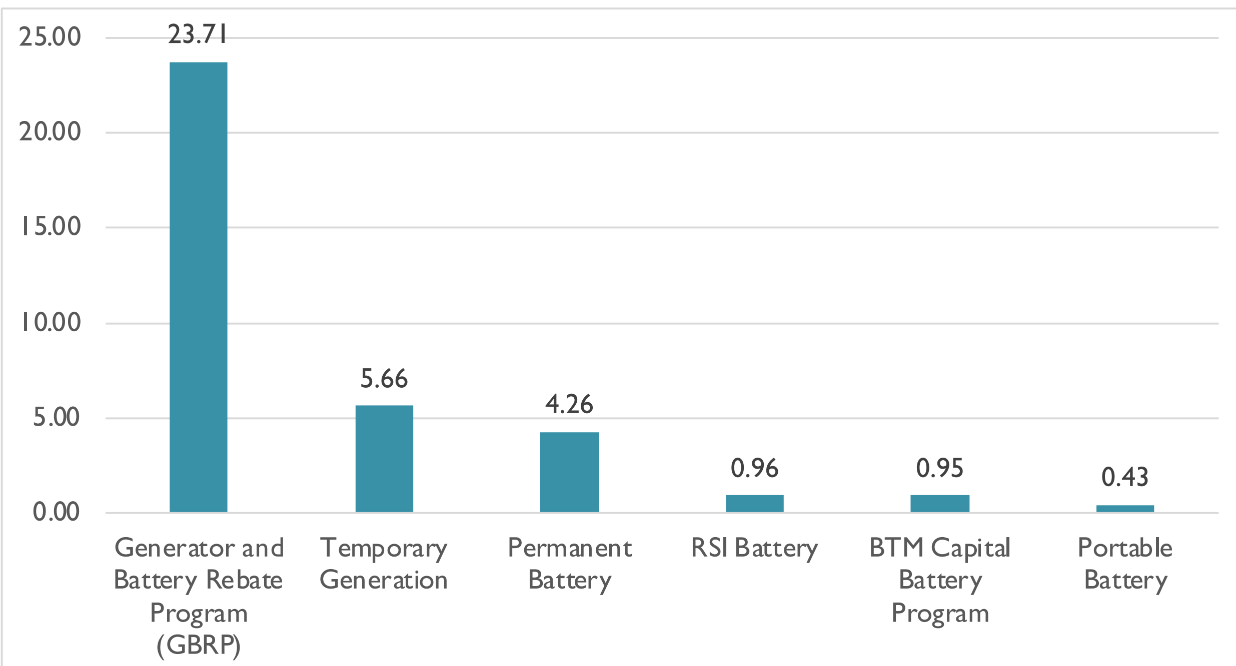
[56] Verdant Associates, *Self-Generation Incentive Program 2023 SGIP Impact Evaluation,* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/2023_sgip_impact_evaluation.pdf., p. 12.

[57] TURN-79, question 18, estimates a 1.1 PVRR multiplier.

2. Utility Ownership and 100 Percent Subsidies for Batteries is Not Cost-effective

PG&E's cost-effectiveness analysis demonstrates that the costs of battery programs which fully subsidize customer costs are not cost-effective. As seen below, both the expense and capital programs which fully subsidize batteries are expected to cost more than the value of lost load for customers experiencing PSPS/EPSS events, as indicated by a cost-benefit ratio (CBR) less than one. On the other hand, by far the most cost-effective program conducted by PG&E, the GBRP, provides relatively small rebates ($300 to $500) for the installation of small generators. It may not be in the ratepayer interest to provide fully subsidized batteries to eligible customers.

Figure 6. CBRs of PSPS and EPSS Mitigation Programs



Source: WP 1-14 GRC Mitigations and Controls and their CBRs_Errata11.10.25.

The GBRP has had the most success in deploying backup power to customers, likely with the use of small, inexpensive generators that run just a few hours a year if an outage occurs. [58]

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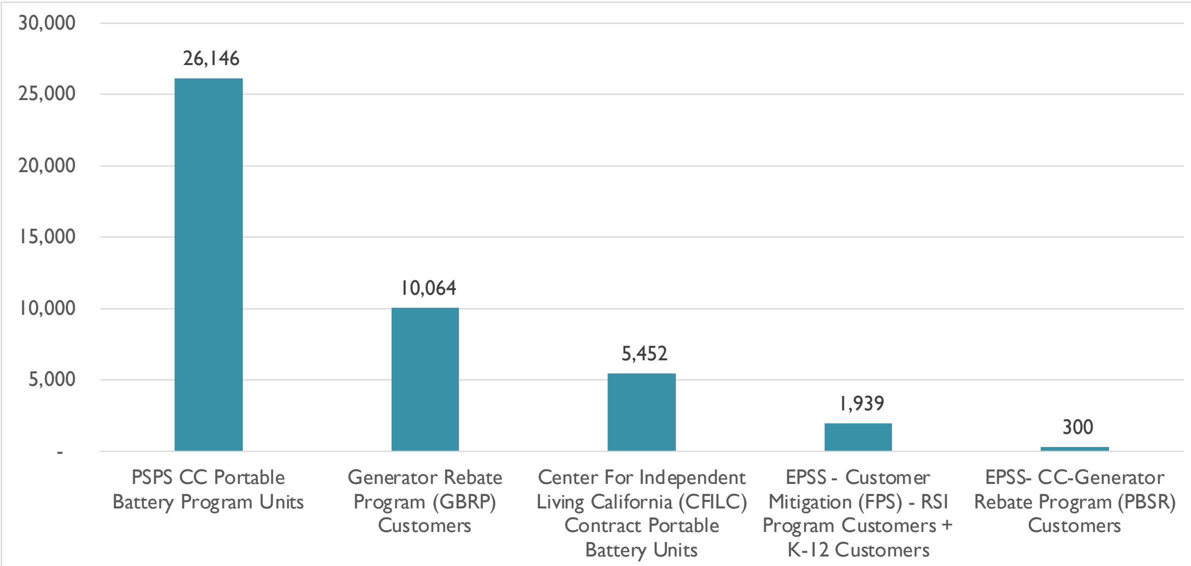
[58] Though I support battery storage (which is also not necessarily a "clean" resource if not paired with solar), the emissions from small generators to mitigate PSPS risk is relatively small. I estimate that if

Figure 7. Number of Backup Power Units Deployed by Program, 2020-2024



Source: TURN-79, question 9, attachment 1.

PG&E has deployed a significant amount of backup power through these programs. For context, there are around 121,000 customers in the HFTD PG&E considers to have "elevated," "extreme," or "significant" risk.[59] The utility expects to deploy over 60,000 units of backup power by 2026, so many of these customers may have benefited from these programs already.[60] On the other hand, utility ownership of batteries is unlikely to result in sufficient ratepayer benefits in comparison with costs. Based on a high-level analysis using data provided by PG&E, the present value (PV) of 100 percent subsidized utility-owned batteries costs are significantly more than the potential benefits from avoided system costs from perfectly optimized dispatch.

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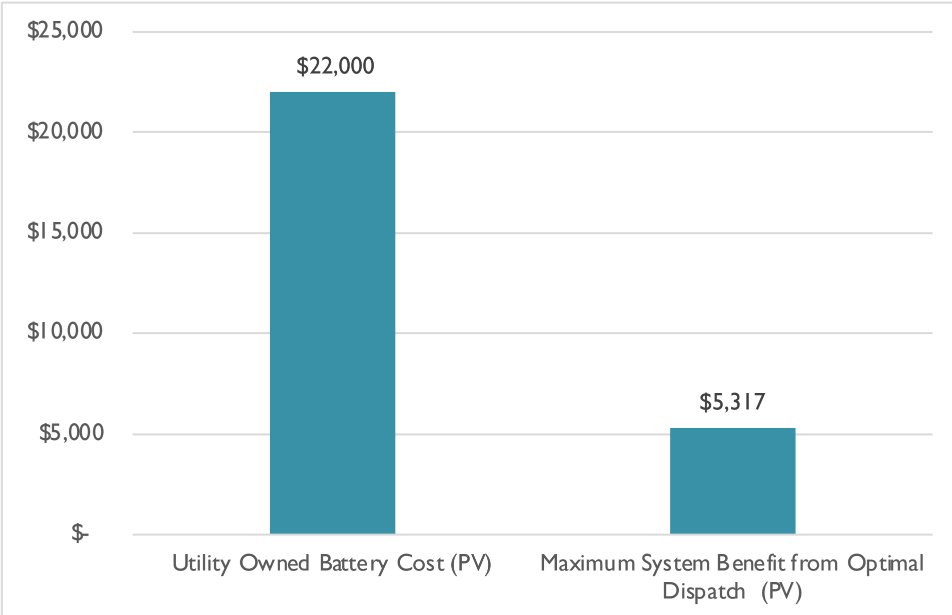
every residential customer in PG&E's territory had operated a small portable generator during PSPS events between 2021 and 2024, their combined NOx emissions would have been between 110 and 290 tons. On an average annual basis, these emissions are less than 0.018% of California's non-wildfire related emissions and less than 0.04% of emissions in PG&E's service territory, based on 2020 emissions data. The analysis uses emissions limits from the California Air Resources Board for a spark-ignited small off-road engine. The range is based on load estimates from 3 to 10 kW. Additional calculations and assumptions are available upon request.

[59] TURN-79, question 10, attachment 1.

[60] TURN-79, question 9, attachment 1.

Figure 8. Costs and Benefits of Optimized Dispatch (Present Value)



Source/Note: TURN-47, question 5, attachment 1. The analysis assumes constant benefits over the lifetime of the battery, 10 years. Benefits are discounted at 7 percent.

Regardless, these values can largely be captured by third parties or enrolling customers in rate design that encourage optimal battery dispatch.

V. CONCLUSIONS AND RECOMMENDATIONS

PG&E has not demonstrated that a utility-owned battery program is in the interest of ratepayers. The utility should do a better job of enrolling customers with batteries in DR programs and rate design that better optimizes dispatch of ratepayer subsidized battery installations to capture the avoided cost values described by PG&E that can accrue to all ratepayers. The program should not be approved.

At the same time, 100 percent subsidies for batteries is not cost-effective, and may not be necessary to support these battery installations. Customers that ascribe a high value to outages will be motivated to participate or can participate in lower-cost alternative programs. TURN recommends the RSI program subsidy be reduced by about 50 percent, which is sufficient to cover the ***BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL*** but not the installation costs. Customers that participate should be strongly encouraged to participate in DR and/or rate designs that help to optimize dispatch, and PG&E should keep track of the number of customers it successfully signs up for these programs. Further, PG&E should work with battery vendors to educate customers on how to set their batteries to charge and discharge appropriately once signed up for DR programs or rates.

I recommend PG&E continue the RSI program. TURN's budget modifies PG&E's by a) reducing the rebate to ***BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL*** per battery, which is expected to cover the entire cost of the battery,[61] and b) adding the expected deployment of battery units from PG&E's capital program to RSI using this subsidy level. TURN does not oppose the small portion of RSI that is intended to support K-12 and other critical infrastructure. These budgets should be capped at the annual approved amount. Subject to the overall budget cap, I would also not oppose a CARE/FERA carveout that subsidizes 100 percent of battery costs and installations. I do not make any adjustments to other backup power programs.

[61] This rebate amount is based on PG&E's estimate for the cost of a battery from TURN-047, question 5, attachment 1, confidential. It is not expected to cover installation costs.

Table 6. PG&E vs. TURN RSI and Capital Battery Program Forecasts

PG&E	2027	2028	2029	2030
Residential Storage Initiative (Res Batteries)	$ 41,200	$ 6,190	$ 6,213	$ 5,710
BTM Capital Battery Program	$ 13,000	$ 26,000	$ 26,000	$ 26,000
Total	**$ 54,200**	**$ 32,190**	**$ 32,213**	**$ 31,710**
TURN	2027	2028	2029	2030
Residential Storage Initiative (Res Batteries)	$ 28,760	$ 16,611	$ 16,623	$ 16,365
BTM Capital Battery Program	$ -	$ -	$ -	$ -
Total	**$ 28,760**	**$ 16,611**	**$ 16,623**	**$ 16,365**
TURN-PG&E	$ (25,440)	$ (15,579)	$ (15,590)	$ (15,345)

Source/note: WP Table 6-5 (with corrections); TURN-047, question 5, attachment 1 CONF; TURN-079, question 9, attachment 1. The budget includes $1.25 million in annual administrative costs as described WP Table 6-5 notes 5 and 6.

This concludes my testimony.

VI. Statement of Qualifications of Eric Borden

My name is Eric Borden. I am employed by Synapse Energy Economics (Synapse). The business address of Synapse is 485 Massachusetts Ave, Suite 3, Cambridge, MA 02139. I have over ten years of experience in the energy industry and joined Synapse in 2022. At Synapse I lead projects, write reports, and provide expert testimony in multiple subject matter areas, including: ratemaking, rate design, revenue requirements, distributed generation, cost-effectiveness of demand-side resources, risk modeling, wildfire-related policies and expenditures, electric vehicles, and rate cases. I have testified before the California Public Utilities Commission on multiple occasions with regard to wildfire-related expenditures, risk modeling, and other issues pertinent to my testimony here.

From 2015 to 2022, I was an Energy Expert at The Utility Reform Network (TURN). My resume is attached to this testimony.

Synapse Energy Economics, Inc.

Eric Borden, Principal Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA*. Principal Associate,* May 2022 – Present

- Sponsors expert testimony and performs analyses related to utility electric vehicle incentives and policy, wildfire mitigation strategies and costs, risk modeling, rate design, cost allocation, and revenue requirement issues in General Rate Cases and Multi-year Rate Plans.
- Conducts research and analysis related to the cost-effectiveness of distributed energy resources and Integrated Resource Plans.
- Examines utility performance incentives and provides expertise on ratemaking issues.

The Utility Reform Network (TURN), San Francisco, CA*, Energy Policy Expert,* February 2015 - May 2022

- Prepared testimony, conducted analyses, drafted comments, and represented TURN in various proceedings at the California Public Utilities Commission (CPUC) related to general rate cases, wildfire-related safety applications, electric vehicle charging infrastructure, utility procurement, rate design, and demand response.

4 Thought Energy LLC, Chicago, IL. *Senior Energy Analyst*, June 2013 – January 2015

- Created financial models to forecast profits of potential site installations
- Researched state and regional public policy frameworks governing CHP
- Conducted analyses over electricity and natural gas price trends
- Developed presentations and marketing materials for investor meetings

International Renewable Energy Agency (IRENA) Bonn, Germany. *Consultant,* February 2014 – October 2014

- Hired to write a report on worldwide electricity sector battery storage, including primary applications for renewable energy integration, market developments, trends, and case studies
- Conduct research, review literature, interview key industry players, develop case study material
- Travel to Bonn, company sites, and research facilities
- Written report will be sent to policymakers in 167 IRENA member countries

Alexander von Humboldt Foundation (hosted by DIW Berlin), Berlin, Germany. *German Chancellor Fellow*, July 2012 – November 2013

- Research Project: “Energy Storage Technology and the Large-Scale Integration of Renewable Energy”

- Investigated the role of energy storage in Germany for renewable integration through literature review, interviews with German energy experts, and analysis comparing public policy support in Germany and the U.S. for storage technologies
- Invited to hold a presentation at the International Renewable Energy Storage Conference and Exhibition (IRES 2013)
- Discussions with German businesses and governmental ministries; special visit to European Union and NATO headquarters in Brussels
- Attended energy conferences and workshops in Berlin

The Kenrich Group, LLC, Chicago, IL. *Senior Consultant*, June 2008 – July 2009

- Consulted for multiple energy utilities in legal disputes with the Department of Energy (DOE)
- Performed detailed research and quantitative/qualitative analysis to analyze financial impact related to construction of coal-fired power plants, liquid natural gas facilities, and other types of construction
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting KRG's expert opinion

Charles River Associates, Chicago, IL. *Associate - Intellectual Property*, July 2006 – May 2008

- Developed complex financial models including discounted cash flow, lost profit, and regression analyses to support expert reports within the context of intellectual property and financial litigation in multiple industries
- Created valuation models and supporting materials to value business entities
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting CRA's expert opinion

EDUCATION

University of Texas, LBJ School of Public Affairs, Austin, Texas
Master of Public Affairs, specialization in Natural Resources and the Environment, 2012

Washington University, St. Louis, MO
B.S.B.A. Finance, Entrepreneurship, 2006

PUBLICATIONS

Borden, E., C. Resor, M. Bandyk, A. Zeng, A. Glaser Schoff, T. Gyalmo, P. Knight, S. Shenstone-Harris. 2025. *Policy Interventions to Address Rising Electricity Costs in New Jersey*. Synapse Energy Economics for the Natural Resources Defense Council and Evergreen Collaborative.

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Electric Vehicles and Public Charging Infrastructure: Impediments and Opportunities for Success in the United States, The University of Texas at Austin, 2012.

Clean Energy Technology and Public Policy, LBJ Journal of Public Affairs, editor and contributor, 2011.

TESTIMONY

Minnesota Public Utilities Commission (Docket No. E002/GR-24-320): Direct Testimony and Attachments of Eric Borden on behalf of The Minnesota Department of Commerce Division of Energy Resources in the matter of the Application of Xcel Energy, for Authority to increase rates for electric service in Minnesota. August 22, 2025.

Wisconsin Public Services Commission (Docket No. 6630-CG-140): Direct Testimony of Eric Borden regarding the Application of Wisconsin Electric Power Company for a Certificate of Authority under Wis. Stat. 196.49 and Wis. Admin. Code PSC 133.03 to Construct a New Liquefied Natural Gas Facility and Associated Natural Gas Pipelines in the City of Oak Creek, Milwaukee County, Wisconsin. On Behalf of Sierra Club. January 20, 2025.

California Public Utilities Commission (A.23-12-001): Direct Testimony of Eric Borden addressing Pacific Gas and Electric Company's 2023 Wildfire Mitigation and Catastrophic Event Expenditure Request regarding enhanced vegetation management. On behalf of The Utility Reform Network. November 1, 2024.

Nova Scotia Utility and Review Board (NSUARB M11877): Direct Testimony of Eric Borden in the Matter of an Application by Eastward Energy Incorporated for the Approval of a Schedule of a Customer Retention Program Recovery Rate. October 31, 2024.

Maine Public Utilities Commission (Docket No. 2024-00137): Direct Testimony of Eric Borden and Caroline Palmer regarding Maine Public Utilities Commission Follow-On Proceeding to Further Investigate Stranded Cost Rate Design. October 1, 2024.

Regulatory Commission of Alaska (U-23-048): Joint Testimony of Eric Borden and Paul Chernick in the matter of the Tariff Revisions Designated as TA-422-121 filed by Chugach Electric Association, Inc. On behalf of Renewable Energy Alaska Project (REAP) Regarding Rate Design. March 14, 2024.

Public Service Commission of South Carolina (Docket No. 2023-233-E): Direct Testimony of Eric Borden in the matter of the Application of Duke Energy Carolina's, LLC for increase in electric rates. On behalf of the South Carolina Department of Consumer Affairs. April 8, 2024.

California Public Utilities Commission (A.23-05-010): Direct Testimony of Eric Borden addressing Southern California Edison's Test Year 2025 General Rate Case Wildfire Grid Hardening Investments. On behalf of the Utility Reform Network. February 29, 2024.

Maryland Public Service Commission (Case No.9702) Direct Testimony of Eric Borden in the matter of the Application of Potomac Electric Power Company for an Electric Multi-Year Plan for the distribution of electric energy. On behalf of The Office of People's Counsel. December 15, 2023.

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Public Service Commission of Wisconsin (Docket No.6680-UR-124): Direct Testimony of Eric Borden regarding the Application of Wisconsin Power and Light Company for Authority to Adjust Electric and Natural Gas Rates. On behalf of Clean Wisconsin. September 5, 2023.

Maryland Public Service Commission (Case No.9692): Direct Testimony of Eric Borden on the matter of the Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of The Office of People's Counsel. June 30, 2023.

Nova Scotia Utility and Review Board (NSUARB M10960): Direct Testimony of Eric Borden on the Matter of an Application by Eastward Energy Incorporated for Approval of a Schedule of Rates, Tolls and Charges Pursuant to Section 21 of the Gas Distribution Act. On behalf of the Counsel to Nova Scotic Utility and Review Board. April 12, 2023.

California Public Utilities Commission (A.22-05-016): Prepared Testimony Addressing San Diego Gas and Electric's Test Year 2024 Wildfire Mitigation Hardening Measures and Related Wildfire Risk Modeling Issues for The Utility Reform Network. March 27, 2023.

California Public Utilities Commission (A.22-05-015/A.22-05-016): Prepared Testimony of Eric Borden and Courtney Lane Addressing Quantitative Risk Analysis Issues in Sempra's 2024 Test Year General Rate Case for The Utility Reform Network. March 27, 2023.

Public Service Commission of South Carolina (Docket No.2022-254-E): Direct Testimony of Eric Borden regarding the Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges. On behalf of South Carolina Department of Consumer Affairs. December 1, 2022.

State of Illinois, Illinois Commerce Commission (Docket 22-0432/22-0442): Direct Testimony of Eric Borden and Courtney Lane regarding the Petition for Approval of Beneficial Electrification Plan Under the Electric Vehicle Act, 20 ILCS 627/45 And New EV Charging Delivery Classes Under the Public Utilities Act, Article IX. On behalf of The People of the State of Illinois. September 22, 2022.

Public Utilities Commission of Maine (Docket No. 2022-00152): Direct Testimony of Melissa Whited and Eric Borden regarding Central Maine Power Company's request for rate design increase and changes. On behalf of the Maine Office of the Public Advocate. December 2, 2022.

California Public Utilities Commission (A.21-06-021): Prepared Testimony Addressing Pacific Gas and Electric's Test Year 2023 General Rate Case – Wildfire Mitigation and New Customer Connections Cost Requests. June 13, 2022.

California Public Utilities Commission (A.21-09-008): Prepared Testimony Addressing the Reasonableness of Pacific Gas and Electric 2020 Vegetation Management Balancing Account Overspend. May 25. 2022.

California Public Utilities Commission (A.21-06-022): Prepared Testimony Addressing Pacific Gas and Electric's Framework for Substation Microgrid Solutions. March 30, 2022.

California Public Utilities Commission (A.21-10-010): Prepared Testimony Addressing Pacific Gas and Electric's Electric Vehicle Charge 2 Proposal. March 2, 2022.

California Public Utilities Commission (A.20-09-019): Prepared Testimony Addressing Pacific Gas and Electric's Wildfire Mitigation Memorandum Accounts. April 14, 2021.

California Public Utilities Commission (A.19-08-013): Prepared Testimony Addressing Southern California Edison's Test Year 2021 Track 2 General Rate Case Memorandum Account Request – Wildfire Expenditures. September 4, 2020.

California Public Utilities Commission (A.20-03-004): Joint Testimony with Eduyng Castano (SCE) Addressing Data Collection and Evaluation of the New Homes Battery Storage Pilot Program. September 1, 2020.

California Public Utilities Commission (A.19-10-012): Prepared Testimony Addressing San Diego Gas and Electric's Power Your Drive 2 Electric Vehicle Charging Infrastructure Proposal. May 18, 2020.

California Public Utilities Commission (A.19-08-013): Prepared Testimony Addressing Southern California Edison's General Rate Case Wildfire Management, Wildfire Risk, Vegetation Management, and New Service Connection Policy Issues and Cost Forecasts. May 5, 2020.

California Public Utilities Commission (A.18-12-009): Prepared Testimony Addressing Pacific Gas and Electric's Enhanced Vegetation Management and System Hardening Wildfire Mitigation Expenditures. July 26, 2019.

California Public Utilities Commission (A.18-09-002): Direct Testimony Addressing SCE's Grid Safety and Reliability Program Infrastructure Proposal. April 23, 2019.

California Public Utilities Commission (A.18-06-015): Rebuttal Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal. December 21, 2018.

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California Public Utilities Commission (A.17-12-011): Direct Testimony Regarding Potential Effects of More "Cost Based" TOU Rates and Seasonal Differentiation of Tiered Rates. October 26, 2018.

California Public Utilities Commission (A.18-02-016) et al.: Prepared Testimony Addressing Issues Pertaining to AB 2868 (Energy Storage). August 10, 2018.

California Public Utilities Commission (A.17-12-002) et al.: Prepared Testimony Addressing the Proposal of SCE for Energy Storage Procurement. April 9, 2018.

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California Public Utilities Commission (A.15-02-009): Rebuttal Testimony Regarding PG&E's A.15-02-009 for EV Infrastructure and Education Program. December 21, 2015.

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California Public Utilities Commission (A.14-04-014/R.13-11-007): Testimony Regarding SDG&E's Application for Authority to Build Electric Vehicle Charging Infrastructure. April 13, 2015.

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