BEFORE THE OFFICE OF ENERGY INFRASTRUCTURE SAFETY

OF THE STATE OF CALIFORNIA

APPENDICES

TO THE
OPENING COMMENTS OF THE UTILITY REFORM NETWORK
ON PACIFIC GAS AND ELECTRIC COMPANY'S
2023-2025 WILDFIRE MITIGATION PLAN

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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May 26, 2023

APPENDIX A

TURN Ex Parte Briefing Summary for PG&E 2023 GRC

March 14, 2023

A Rational Approach to Balance Affordability with Customer Safety and Reliability

TURN Briefing Summary:
PG&E 2023 GRC
March 14, 2023

Main Topics For Today's Discussion

1. PG&E's proposal worsens already serious energy affordability concerns and threatens greenhouse gas reduction goals.
2. The Commission has the tools to protect safety and reliability AND prevent a further erosion of affordability.
3. Wildfire Risk Mitigation:
   - PG&E's risk modeling fails to recognize the major risk reduction from preventing compliance failures.
   - *Combining improved compliance and covered conductor deployment* yields the same or *more risk-reduction* as PG&E's question-riddled undergrounding plan.

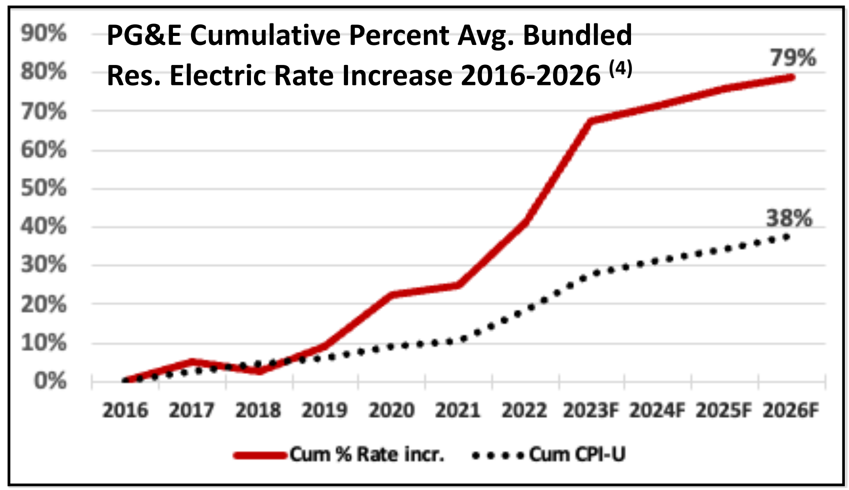
Affordability is *the* Over-Arching Issue of PG&E's 2023 GRC

- **PG&E's cost of electric service is growing less affordable in real economic terms for all but higher income households.** (TURN OB, Sec 1.3.1.3)
- **Low-income customers in inland climate zones could pay 20% of disposable income for energy; minimum wage workers will need to work 2 more hours per month to pay for the same level of usage** (TURN OB. Sec. 1.3.1.3.)
- **Low-income programs are insufficient to protect impacted households** (TURN OB, Sec. 1.3.1.4)

PG&E's 2023 GRC Proposal vs. Illustrative CPI Projections (1)

Year	February 2022 GRC RRQ Proposal ($000) (1)	% Inc.	Update RRQ Proposal ($000) (2)	% Inc.	Illustrative CPI forecast (3)	February Proposal vs. Illustrative CPI
2022	$ 12,214,000		$ 12,214,000			
2023	$ 15,339,000	25.6%	$ 16,175,000	32%	8.00%	17.6%
2024F	$ 16,357,000	6.6%	$ 17,233,000	7%	2.50%	4.1%
2025F	$ 17,112,000	4.6%	$ 18,083,000	5%	2.40%	2.2%
2026F	$ 17,673,000	3.3%	$ 18,764,000	4%	2.40%	0.9%
Total 4-Year RRQ increase	$ 17,625,000	44.7%	$21,399,000	53.6%	16.8%	27.9%

(1) TURN OB, p. 1.
(2) TURN OB, p. 2.
(3) TURN OB p. 8 and p.27 .



(4) Based on TURN OB, p. 9, Table 1, and p. 27, and Exhibit TURN-613A, Response to DR 265-9, Table 3.

PG&E's Request Poses Multiple Threats to Affordability

1. **Double-digit GRC requests on top of rate increases in multiple other proceedings**

2. **Hidden long-term rate impacts of huge increases in capital spending, which the CPUC has found to be a key rate increase driver (TURN OB, Sec. 1.3.2.1)**
   - Driven by undergrounding, PG&E's Reply Brief proposal would increase 2023-2026 spending by 111% over 2022 adopted levels. (TURN OB, p. 19, Table 5, updated for PG&E Reply Brief)
   - While rate case period impacts of PG&E's undergrounding plan on RRQ and rates are minimal, the huge additional UG costs will cause "pancaking" increases to rate base that will defeat future efforts to control rate hikes

3. **Balancing and Memo Account Structure Favors PG&E at Ratepayer Expense** (TURN OB, Sec. 12.3)
   - Allow substantial over-spending recovery w/o demonstration of reasonableness
   - Lack of transparency as true rate impacts are only known after spending has occurred
   - Discourages cost discipline; mis-directs utility efforts toward creative accounting, not cost-cutting

4. **Attrition request divorced from CPI and long-term spending trends** (TURN OB, Sec. 11)
   - Attrition must not insulate utilities from normal business pressures
   - PG&E proposal defeats key goal of providing an incentive to control costs

PG&E's Request Threatens Key Policy Goals

- Increased unaffordability of electric rates undermines climate strategy of switching from fossil fuels to electricity

- Increased unaffordability of gas rates exacerbates problem of stranded gas costs borne by a shrinking customer base, including customers unable to electrify

- The bill impacts in the rate case period and beyond, particularly for low income and inland communities, undermine the Commission's ESJ goals

TURN's Affordability Policy Recommendations

- **Weed Out Unnecessary Spending**. Approve ONLY costs both necessary for safety and reliability and affordable for PG&E customers. Pay close scrutiny to large capital programs.
- **Leverage Cost-Effectiveness Analysis.** Use Risk-Spend Efficiency (RSE) data to balance safety and affordability by targeting work where it is most needed and cost-effective.
- **Cap Spending Based on COLA.** To prevent a further erosion of affordability, adopt a COLA-based cap on increases to PG&E's authorized spending and require an alternative COLA-constrained GRC showing in next GRC.
- **2017/2020 Deferred Work Settlement should continue** and include RSE justification for reprioritized work.

Need for a COLA-Based GRC Spending Framework

1. ***Energy must be affordable to be useful.***

2. The Commission has acknowledged the linkage between cost of living growth and bill affordability: *"We [review SCE's GRC request] with a goal of limiting the annual increase in SCE's revenue requirements to, not double the growth in customer income, but rather* ***a true alignment with no more than that growth rate****.* ***It is only by endeavoring to meet that goal, that we can begin to strive for greater affordability****."* (D.19-05-020, p. 20, emphasis added)

3. Non-ratepayer funding sources should be pursued before allowing cost increases above COLA (e.g. Infrastructure Investments and Jobs Act)

Cost-Effectiveness Analysis Is an Important New Tool to Balance Affordability and Safety

CPUC-Developed Risk Spend Efficiency (RSE) Tool Can Prioritize IOU Work and Limit Inefficient Spending

- Developed in a 5-year CPUC process to prioritize risk mitigation spending, capped by the D.18-12-014 Settlement. (TURN OB, Sec. 2.3.2.1)
- 2023 GRC is the first with RSE Analysis available per the D.18-12-014 Settlement.
- “***RSE calculations are critical*** for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds.” (D.21-08-036, p. 38, emphasis added)
- RSEs show relative cost effectiveness. They can also be expressed as Benefit-Cost (B/C) ratios that show cost-effectiveness on a stand-alone basis. (TURN OB, Sec. 2.3.3; TURN RB ,Sec. 2.3.1)

RSEs are now available. Commission should use them to help weed out inefficient spending!

How RSE Increases Ratepayer Value—Gas Program Example

RSE Exposes Low Cost-Effectiveness of Certain Gas Programs

- Per SPD's RAMP report, "very low" RSEs and high ratepayer costs demand CPUC scrutinize cost-effectiveness of gas programs. (TURN OB, Sec. 3.2.1)
- Low RSE results for mature gas programs show riskiest parts of the system have already been addressed.
- TURN recommends significantly scaling back, or, in some cases, rejection of PG&E's inefficient spending on these discretionary programs. (TURN OB, various programs in Secs. 3.3, 3.4, 3.5, and 3.10)

Example of Savings Opportunity: RSE results for PG&E's largest gas pipe replacement proposals *(TURN OB, Sec. 3.2.2)*

Program	4-Year Cost ($M)	RSE/Rank*	B/C Ratio**
Plastic Pipe Replacement	2,502	0.0072/ Bottom 13%	0.0014
Steel Pipe Replacement	752	0.0073/ Bottom 13%	0.0022
ILI Upgrade Replacement	889	0.0796/ Bottom 31%	0.0173

* Rank based on comparison to RSEs for all 247 gas and electric programs scored by PG&E
** For example, B/C Ratio for Plastic Pipe program means that PG&E's proposal would provide 0.14 cents of risk reduction benefits for every dollar spent.

PG&E Offers NO GOOD REASON to Reject RSE-Based Program Funding Decisions

PG&E Admits RSE Analysis Gives Best Assessment of Risk Reduction Benefits (TURN OB, Sec. 2.3.2.3)

- RSEs are not just a "single summary statistic" but based on PG&E's own comprehensive risk analysis by its subject matter experts (TURN OB, Sec. 2.3.2.3).
- RSEs are more useful and transparent than PG&E's *qualitative* discussions in comparing program cost-effectiveness (TURN OB, Sec. 2.3.2.2)
- RSEs reflect robust approach PG&E agreed to in D.18-12-014 Settlement (TURN OB, Sec. 2.3.2.6)

RSE results need not be the ONLY funding decision determinants but cannot be discounted or ignored given the imperative for BOTH Affordability and Safety *(TURN RB, Sec. 2.3.3)***.**

TURN's Wildfire Proposal yields comparable risk reduction at over $4 billion less cost

Summary of TURN's Proposal

1. **PG&E can reduce most of its wildfire risk by a back-to-basics strategy of improving vegetation management and inspection/repair compliance activities**
   - PG&E's risk analysis makes the key mistake of failing to recognize that PG&E's catastrophic wildfires have resulted from compliance failures. (TURN OB/RB, Sec. 4.2.1)
   - CPUC should recognize the significant risk reduction from PG&E's promise to improve compliance.
2. **System hardening should focus on Covered Conductor, which is more cost-effective, quicker to deploy, and more flexible than undergrounding**
3. **Undergrounding should be focused on the riskiest circuits**
4. **When the risk reduction from improved compliance is counted, TURN's proposal results in as much, or more, risk reduction than PG&E's plan,** at **$4.2 billion less cost.**

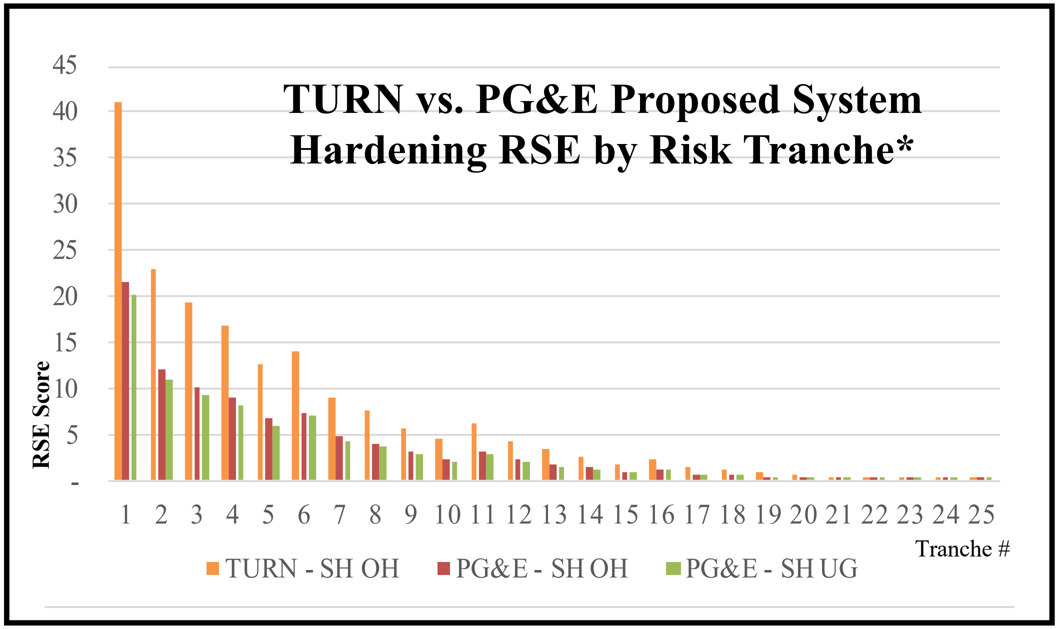
Details of TURN's Wildfire Proposal

1. **Covered Conductor (CC) Should be Primary System Hardening Strategy** (TURN OB, Secs. 4.3.2/4.3.7)
   - **CC is more cost-effective** than undergrounding (see next slide)
   - **CC can be deployed more quickly** without triggering CEQA/permitting/property acquisition challenges
   - **CC can be teamed with other existing and emerging technologies** for more cost-effective risk reduction
2. **TURN proposes more CC than PG&E's original proposal** – 1,800 miles compared to PG&E's 1,480 miles
3. **TURN proposes more undergrounding than in PG&E's original proposal**
   - **200 miles** (50 miles/year) **compared to PG&E's 182 miles** in June 2021 request
4. **TURN's proposal avoids $4.2 billion** in unnecessary capital spending

Covered Conductor More Affordable		
PG&E-2/22 Proposal (1)	**PG&E – Reply Brief Position(1)**	**TURN**
$10.4 B (2)	$6.3 B (3)	$2.1 B

Notes: (1) Does not include September 2022 Update Escalation; (2) Source PG&E OB, p. 380; (3) Source PG&E OB, p. 332.

Covered Conductor is More Cost-Effective than Undergrounding



* Each tranche represents a portion (ranging from 200-2,000 circuit miles) of PG&E's ~ 25,000-mile, HFTD distribution system, generally from highest risk to lowest risk. Source: TURN OB Figure 6, p. 387.

- RSE for CC program – when PG&E's unnecessary asset replacement is removed -- is over 2X higher than UG. **11.0 for CC vs. 5.3 for UG** (TURN OB, Sec. 4.3.2.1)
- RSEs for CC program are higher than UG ***in every tranche*** (graph at left) (TURN OB, Sec. 4.3.2.1)
- These numbers understate CC's RSE advantage. **Results to date show 1.0 UG mile replaces only 0.64 mile of CC** b/c of construction feasibility issues, while PG&E assumed 0.80 miles. Effect is to further reduce UG's RSE. (TURN-11, pp. 32-34; TURN Sur-Reply, p. 9)

PG&E's Undergrounding Program is Unnecessarily Expensive and Unproven

TURN's More-Affordable, Portfolio Proposal Reduces as Much Risk as PG&E's Undergrounding for $4.2 billion* Less Cost to Ratepayers

PG&E Current Proposal Cost: $6.3 B*	TURN Proposal Cost: $2.1 B*
• **PG&E's 10K UG plan was poorly planned**: announced before PG&E assessed feasibility and cost. (TURN OB, Sec. 4.3.1.1) • **Hidden costs and permitting challenges:** UG often needs a different, longer path than overhead lines, which will trigger CEQA delays, uncertainty, and higher cost. (TURN OB, Sec. 4.3.6.1; PG&E RB, p. 361) • **PG&E's ever-changing UG targets are unrealistic and unprecedented,** and vulnerable to completing the easiest, rather than riskiest miles. (TURN OB, Sec. 4.3.3.2) • **PG&E hedges bets on claims of declining costs** by seeking automatic balancing account recovery for costs up to 25% above forecast. (TURN OB, Sec. 4.3.6.2) • **PG&E exaggerates cost savings from UG**. Even with claimed long-term savings, net cost of UG for 10,000 miles is twice cost of equivalent CC. (TURN OB, Sec. 4.3.3.3)	• "Back-to-Basics Strategy" addressing basic equipment repair and past compliance failures, delivers immediate risk reduction and maximum ratepayer value (TURN OB/RB, Sec. 4.2.1) • More cost-effective, flexible, quickly-deployed CC should be primary system hardening strategy (TURN OB, Secs. 4.3.2 and 4.3.7) • UG reserved for highest risk areas where it is most cost-effective. *Excludes September 2022 escalation update.

TURN's Recommendations on Key Issues

TURN Recommended Adjustments (Figures, except Wildfire, are for Test Year and exclude PG&E's 9/22 Update)	***Why TURN Recommends***
Wildfire Spending	
System Hardening. TURN proposes (2023-2026) more covered conductor than PG&E's revised proposal: 1,800 vs. 320 miles, at $975 million higher cost. BUT TURN proposes much less undergrounding, limited to the highest risk circuits: 200 vs. 2,100 miles, at **$5.14 billion lower cost**.	RSEs show covered conductor (CC) (without replacing safe, useful assets) is more than twice as cost-effective as undergrounding, so TURN's recommendation removes much more risk per dollar spent. CC can be deployed faster and can be more flexibly teamed with other existing and emerging wildfire protection technology.
Gas Distribution (GD) and Transmission (GT) Spending	
GD Plastic Pipe Replacement capital (MAT 14D). TURN recommends reducing forecast **by $348 million**, from $520 million **to $172 million**. (TURN OB, Sec. 3.3.1)	RSE analysis shows PG&E's plan provides very little risk reduction benefit compared to the cost. Focus should be on replacing pre-1976 pipe, which based on pipe materials/leak data evidence, as well as PG&E's DIMP model, poses a higher risk than the other pipe PG&E proposes to replace.
GD Steel Pipe Replacement capital (MAT 50B).TURN recommends reducing capital by **$90 million**, from $151 million **to $61 million**. (TURN OB, Sec. 3.3.2)	This program has extremely low RSEs and Benefit-Cost ratios. Focus should be on replacing pre-1924 pipe, which leak data/PG&E's own DIMP model shows poses a higher risk than the other pipe PG&E proposes to replace.
GT In-Line Inspection (ILI) Upgrades (Mat 98C). TURN recommends reducing PG&E's test year capital forecast by **$152 million**, from $207 million to **$55 million**. (TURN OB, Sec. 3.4.1).	PG&E has already addressed the highest risk pipe in this mature program, which results in low RSEs and Benefit-Cost ratios for the proposed work. PG&E's proposal to perform 12 projects/year should be reduced to no more than 4. In addition, TURN's recommendation corrects analytical errors that reduce unit costs 21%.

TURN's Recommendations on Key Issues

TURN Recommended Adjustments	*Why TURN Recommends*
Gas Distribution and Transmission (cont.)	
GD Cross Bore Inspections. Reduce expense forecast **by $21 million** from $34 million to **$13 million** (TURN OB, Sec. 3.3.5)	With highest risk work in San Francisco already completed, PG&E proposes to expand the program to much less risky areas, w/ extremely low cost-effectiveness. (RSE in bottom 23%, B/C ratio of 0.006). TURN recommends keeping the average number of annual inspections constant and a reduced unit cost to reflect lower costs outside San Francisco.
GT Strength Testing and Replacement. Reduce non-TIMP capital forecast **by $42 million** from $140 million to **$98 million** and expense forecast **by $24 million** from $35 million to **$11 million**. (Ex. TURN-04, Table 16; PG&E OB, Tables 3-23, -24, -25; TURN OB, Sec. 3.4.7) (Note: PG&E's OB presents updated PG&E forecasts that are not reflected in Ex. TURN-04, Table 16 or TURN's OB.)	PG&E's forecast includes 65 non-high priority projects that are not required to be completed during this GRC cycle. TURN removes these projects and also provides a more reasonable method for estimating project costs and calculating disallowances for pipelines lacking proper documentation.
GD and GT Overpressure Programs (MATs 76G, 50N, JTX and FHQ). TURN recommends reducing capital and expense for this program by **$64 million to zero** and providing no further funding going forward. (TURN OB, Sec. 3.5.4)	These mature programs provide secondary protection on top of regulators and monitors. PG&E has already addressed riskiest assets. PG&E's RSEs thus show minimal risk reduction compared to the costs (bottom 32% of PG&E's programs, B/C ratios below 0.02).
Transmission Integrity Management Plan Balancing Account and Memorandum Account (TIMPBA and TIMPMA) – **The CPUC should maintain the status quo of a one-way TIMPBA and a TIMPMA to track costs associated with any new safety regulations.** (TURN OB, Sec. 3.14.2.1)	The CPUC has twice rejected PG&E's requests to convert the TIMPBA to a two-way account and should do so here for the same reason – to provide PG&E a meaningful incentive to control costs. The TIMPMA, as currently scoped, provides PG&E appropriate protection against costs arising from any new regulations that may be adopted.

TURN's Recommendations on Key Issues

TURN Recommended Adjustments	*Why TURN Recommends*
Gas Storage	
Claimed Need for Additional Storage Withdrawal Capacity. Contrary to PG&E's inflated forecasts, the CPUC should find no capacity shortfall during the rate case period. Thus, there is no need to keep the Los Medanos storage field, drill new wells at McDonald Island or Gill Ranch, or take any other measures to address a non-existent shortfall. (TURN OB, Secs. 3.6.1, 3.6.2, 3.6.4, 3.6.5, 3.6.6). The capital forecast for gas storage programs should be reduced by **$42 million** from $106 MM to **$64 million** and the expense forecast reduced by **$6 million** from $18 million to **$12 million**. (TURN OB, Sec. 3.6.7)	PG&E's forecasts are outdated and poorly supported. (E.g. PG&E's core forecast is based on a proprietary model that PG&E's witness could not explain and which produced results counter to the post-2013 trend of steadily declining gas demand). TURN's demand forecasts are grounded in more realistic and transparent data, while still conservative. For example, TURN's figures assume Diablo Canyon will be retired in 2024 and 2025, which now seems less likely per SB 846. If Diablo continues to operate, the need for gas-fired electric generation would be lower than TURN forecasts.
Electric Distribution	
Overhead Distribution Maintenance (MATs KAA and 2AA). Reduce expense forecast by **$38 million** from $58 million to **$20 million** and reduce capital forecast by **$85 million** from $205 million to **$120 million** (TURN OB, Sec. 4.11.1).	PG&E has not justified the doubling (expense) and tripling (capital) of the unit costs for these programs since 2018, failing to provide evidentiary support for its changing explanations. Ratepayers should not pay for cost premiums resulting from the need for remediation of PG&E's history of unreasonable inspection practices.
Pole Replacement (MAT 07D). Reduce capital forecast costs **by $80 million** from $369 million to **$289 million** (TURN OB, Sec. 4.12).	PG&E's huge proposed increase over 2020 recorded costs reflects a premium to address a backlog of pole replacements resulting from PG&E's unreasonable inspection history. TURN's forecast removes unnecessary and unreasonable costs and provides a reasonable budget for this program.

TURN's Recommendations on Key Issues

TURN Recommended Adjustments	*Why TURN Recommends*
Electric Distribution	
Electric Distribution Capacity. Reduce total capital forecast for two capacity programs **by $30 million** from $139 million to **$109 million** (TURN OB, Sec. 4.17).	TURN's reduction accounts for the reduced peak load from agricultural customers due to the implementation of new Time-of-Use tariffs in March 2021.
Electric Distribution New Residential Connections. Reduce capital forecast by **$54 million**, from $262 million to **$208 million**. (TURN OB, Sec. 4.18).	PG&E's forecast is based on a sharp increase to the historical growth rate in residential housing permits based on a proprietary model that PG&E did not make available to parties. TURN's forecast is based on a more reasonable growth rate for new housing construction based on the historical trend.
Community Rebuild Program. **The CPUC should deny any rate recovery at this time for the over $500 million i**n recorded and forecast costs associated with rebuilding facilities and restoring service in the town of Paradise. (TURN OB, Secs. 4.23, 10.4)	These rebuilding costs are necessary because of the devastation resulting from the catastrophic Camp Fire caused by PG&E, for which PG&E has pled guilty to 85 criminal counts. PG&E has failed to demonstrate the reasonableness of its actions that caused that fire. If PG&E wishes to pursue recovery of these costs, it should do so in a future, single CEMA request covering all of the rebuilding costs. PG&E must also be barred from including any Community Rebuild capital spending from 2019-2022 in its 2023 rate base before that spending has been found reasonable.
Wildfire Mitigation and Vegetation Management Balancing Accounts. **The CPUC should modify these accounts to make them each one-way balancing accounts**. If the CPUC deems it necessary to allow PG&E an opportunity to recover above-authorized costs, the CPUC can create a companion memorandum account for each and require a demonstration of reasonableness before rate recovery of such costs. (TURN OB, Secs. 4.24.1, 12.3)	PG&E's proposal would recover $275 million more in annual veg. management costs and $165 million more in annual wildfire mitigation RRQ, *without any showing of reasonableness*. PG&E should not be excused from demonstrating reasonableness for a substantial and increasing share of its revenue requirement. TURN's proposal increases PG&E's cost-control incentive, promotes transparency, and is consistent with fundamental principles of utility regulation.

TURN's Recommendations on Key Issues

TURN Recommended Adjustments	*Why TURN Recommends*
Customer and Communication	
Gas AMI Module Replacement. **The CPUC should deny recovery at this time of the over $600 million in capital costs and additional expenses** associated with the premature failure of Gas AMI communications modules. (TURN OB, Sec. 6.10)	PG&E has failed to establish the reasonableness of its actions leading up to the premature failure of equipment it selected, installed, maintained and operated. PG&E can renew its request, with the required showing, in its 2027 GRC.
Billing System Upgrade Project. **The CPUC should deny recovery at this time of the $174 million in capital and expense** that PG&E forecasts for this project. (TURN OB, Sec. 6.11)	PG&E failed to provide the information necessary to determine whether the proposal is reasonable -- including a cost-benefit analysis, and an explanation of the requirements, features, and functionalities for the proposed new system. PG&E should be directed to file a separate application with the necessary information to determine the project's reasonableness.
Human Resources	
Short-Term Incentive Compensation – reduce PG&E's total request for its Short-Term Incentive Program (STIP), which primarily benefits salaried employees, by **$146 million** from $233 million to **$87 million** (TURN OB, Sec. 8.3).	The 25% of STIP based on PG&E's financial performance should be disallowed from recovery as: (1) it is based on a measure of performance that excludes losses resulting from management missteps, thereby providing a disincentive for improved management; and (2) the CPUC has repeatedly disallowed funding for financial metrics as benefitting shareholders, not ratepayers. The remaining STIP goals incentivize activities that benefit both shareholders and ratepayers and the cost should therefore be shared 50/50.

TURN's Recommendations on Key Issues

TURN Recommended Adjustments	*Why TURN Recommends*
Results of Operations	
Depreciation. **The Commission should not adopt PG&E's proposal to increase gas distribution depreciation expense by $47 to $186 million** over the course of this GRC cycle as a measure to protect the utility from stranded investment due to California's decarbonization policy.	PG&E proposes to switch from straight-line depreciation to a Units of Production (UoP) method for gas distribution plant in order to achieve higher depreciation rates and thereby accelerate the utility's recovery of its investment in gas distribution plant. The Commission should deny this request with the expectation that potential stranded cost issues and other decarbonization policy issues will be addressed in a more fair and balanced manner in R.20-01-007, the rulemaking addressing long-term gas system planning.
Working Cash. PG&E's request should be reduced **by $792 million** to reflect realistic forecasts of revenue lag, goods expense lag, and income taxes. The CPUC should adopt a revenue lag forecast of 46.92 days based on years that were not impacted by the Covid Pandemic and the moratorium on shutoffs in California. The CPUC should adopt a goods and services expense lag of 36.67 days to reflect standard best utility industry cash management practices. The CPUC should adopt a federal income tax expense lag of 292 days and a state income tax lag of 365 days based on the fact that PG&E has not been a cash taxpayer over the last decade and does not expect to pay cash taxes until 2026. Should PG&E expect to become a cash taxpayer during its next GRC cycle, PG&E can include this in its next GRC request.	PG&E's showing should justify every dollar of ratepayer funding. Even with small RRQ impacts, the Commission should require that forecast values be reasonable and adequately supported. This view has informed all of TURN's recommendations in this proceeding.

TURN's Recommendations on Key Issues

TURN Recommended Adjustments	*Why TURN Recommends*
Post Test-Year Ratemaking	
Adopt TURN's two-part attrition mechanism that separately addresses expense and capital. For **O&M**, escalate during the Post Test-Year (PTY) period using CPI-U rather than PG&E's escalation factors, to provide PG&E an incentive to manage and reduce costs during the PTY period. For **capital**, TURN proposes that the Commission adjust capital costs for the PTY based on a forecast of capital additions that results from trending seven years (2015-2021) of recorded capital additions, to normalize utility spending variations over time. TURN also recommends that the Commission adopt budget-based capital attrition for three non-standard categories: wildfire system hardening, gas storage, and Diablo Canyon power plant (a more limited list than proposed by PG&E). (TURN OB, Sec. 11; TURN RB, Sec. 11)	TURN's two-part attrition mechanism meets the objectives of attrition and reasonably balances the interests of ratepayers and shareholders during the post-test year period. An attrition mechanism should provide the utility with an incentive to manage and reduce its costs during the post-test year period, rather than cover all potential cost changes. Attrition should not be used to insulate PG&E from the economic pressures which all businesses experience. Budget-based attrition should only be used for cost categories that are experiencing extraordinary changes that make a forecast based on trends inappropriate – here, wildfire system hardening, gas storage, and Diablo Canyon. PG&E's proposal for all other expense and capital categories is too complex and comes close to a "cost plus" guarantee that defeats the key goal of providing an incentive to control costs. PG&E's proposal is too generous to shareholders at a time when rate restraint is necessary to avoid deepening the affordability crisis and undermining achievement of California's climate goals.

APPENDIX B

TURN Testimony of Eric Borden in PG&E's 2023 GRC

Addressing PG&E's Wildfire Mitigation Measures

CPUC Docket: A.21-06-021
Witness: Borden
Exhibit: TURN-11

PREPARED TESTIMONY OF
ERIC BORDEN

ADDRESSING PACIFIC GAS AND ELECTRIC'S TEST YEAR 2023 GENERAL RATE CASE WILDFIRE MITIGATION MEASURES

Submitted on Behalf of

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I. Introduction and Overview of TURN's Recommendations

On November 8, 2018, the failure of a C-hook, a piece of equipment on one of Pacific Gas and Electric's (PG&E's) transmission towers, resulted in an ignition that caused one of the most catastrophic wildfires in California history. The Commission's Safety and Enforcement Division (SED) Report on the incident found PG&E was out of compliance with the Commission's regulations because the equipment was improperly inspected, improperly maintained, and improperly replaced or reinforced.[1] The failure of the C-hook resulted in the tragic death of 85 residents of Paradise and massive ecological and financial damages. Since this event, California utilities have been put onto an entirely different trajectory to address the risk of utility-caused wildfires, which appears to have been under-appreciated in years past. Whether that trajectory will effectively reduce wildfire risk and benefit ratepayers is still not clear. What is clear is that PG&E's actions in the years since demonstrate that a light-touch regulatory approach does not work for this utility. It requires strong regulatory guidance through firm budgets, clear guidelines for how these budgets should be spent, and independent monitoring and verification for the work that is done.

There is nothing normal about PG&E's Test Year (TY) 2023 General Rate Case (GRC) request. The same utility that recently pleaded guilty to 84 felony counts related to the Camp Fire now seeks unprecedented rate increases on the backs of a wary customer base that is already struggling with the cost of living in California, including household energy costs.[2] Despite the fact that the utility had multiple years to prepare its GRC request, $7 billion was added mid-course through this proceeding for a large-scale undergrounding proposal, which apparently was not a part of the utility's plans when it filed its GRC in June of 2021, even though it was announced by its CEO the very next month.

TURN does not deny that conditions in PG&E's service territory have worsened over the years due to climate change, and that PG&E has sought in recent years and with increasing effort to

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[1] D.20-05-019, p. 11.
[2] See TURN Witness Jennifer Dowdell's Testimony on Affordability (TURN-3).

remedy its compliance failures regarding maintenance of equipment and vegetation management. We are the first to applaud these efforts. With the benefit of the Safety Model Assessment Proceeding (S-MAP) Settlement adopted in D.18-12-014 and the input of the Safety Policy Division and the parties, PG&E's risk modeling has improved tremendously in the last few years, giving the Commission additional data and tools to understand the cost-effectiveness of its various programs. Yet rather than adopt a "compliance first" wildfire mitigation strategy – shown in this testimony to be by far the most effective strategy – PG&E has adopted a "cost first" approach, emphasizing the single most expensive, complex, and risky strategy at its disposal, undergrounding utility power lines. Unfortunately, the utility does not use its increasingly sophisticated risk modeling to help scope or determine its program proposals; it appears to operate the other way around, whereby pre-determined program proposals drive risk modeling results that are generally presented but not used to shape PG&E's proposals.

TURN does not oppose use of non-ratepayer funds for a large-scale undergrounding program to protect against the results of continued failure by PG&E to fully comply with its regulatory obligations. But if the use of ratepayer funds is the only option here, it is up to the Commission to ensure that those funds are used wisely to achieve both safe and affordable electric service. To achieve these twin goals, undergrounding must be used as a specialized tool for the miles of system where it makes the most sense, not as the primary wildfire mitigation measure.

Despite the false dichotomy presented by PG&E's Application, safe and affordable electric service *is* possible. When the facts about utility wildfire risk, as will be presented in this testimony, are understood, the Commission can craft a sound wildfire mitigation strategy that aggressively reduces wildfire risk and safeguards the affordability of electric rates.

TURN's analysis of PG&E's forecast, underlying data, and risk modeling finds the following:

- Based on historical data and analysis of PG&E's risk modeling, the most effective approach to reducing utility wildfire risk in PG&E's service territory is ensuring compliance with state law. This is indicated by the fact that 100% of catastrophic and destructive fires caused by PG&E equipment between 2015-2020 were found by expert state investigators to be the result of compliance violations.

- PG&E's proposal to rely on undergrounding as the primary wildfire mitigation measure is inadequately supported and unduly costly. PG&E should focus its efforts on the deployment of covered conductor over the GRC period (2023-2026) which significantly reduces risk of ignition and costs substantially less than undergrounding.

- In addition to clear budget forecasts that PG&E should adhere to over the GRC period, wildfire accountability measures are necessary to ensure PG&E accomplishes its work in the most cost-effective manner possible – i.e. maximizing safety benefits for the dollars spent. This includes setting standards to ensure system hardening work is accomplished in a risk-informed manner (from highest to lowest risk), prescribing maximum unit cost thresholds, and leveraging outside funds plus lowering financing costs if the Commission adopts a large-scale undergrounding proposal (which TURN strongly opposes based on the substantial evidence presented in this testimony).

- The methodologies used to forecast costs for the Public Safety Power Shutoffs and Enhanced Powerline Safety Setting programs are flawed and likely to over-forecast the necessary costs to accomplish these activities over the GRC period. TURN provides analysis and an alternative methodology to more accurately forecast these costs.

These findings and recommendations result in the following recommended changes to PG&E's forecast, as presented in PG&E's supplemental testimony of February 25, 2022.

Table 1. Summary of Cost Recommendations
PG&E vs. TURN ($ Thousands)

	System Hardening - Overhead				
	2023	2024	2025	2026	Total
PG&E	$ 265,377	$ 81,507	$ 83,918	$ 86,402	$ 517,204
TURN	$ 358,200	$ 367,871	$ 377,804	$ 388,005	$ 1,491,880
TURN-PG&E	**$ 92,823**	**$ 286,364**	**$ 293,886**	**$ 301,603**	**$ 974,676**

	System Hardening - Underground				
	2023	2024	2025	2026	Total
PG&E	$ 1,192,578	$ 2,415,857	$ 2,907,624	$ 3,337,360	$ 9,853,419
TURN	$ 166,888	$ 158,209	$ 148,941	$ 139,057	$ 613,094
TURN-PG&E	**$ (1,025,691)**	**$ (2,257,647)**	**$ (2,758,683)**	**$ (3,198,303)**	**$ (9,240,324)**

	Enhanced Powerline Safety Settings				
	2023	2024	2025	2026	Total
PG&E	$ 151,129	N/A	N/A	N/A	$ 151,129
TURN	$ 87,049	N/A	N/A	N/A	$ 87,049
TURN-PG&E	**$ (64,080)**	**N/A**	**N/A**	**N/A**	**$ (64,080)**

	Public Safety Power Shutoff Events				
	2023	2024	2025	2026	Total
PG&E	$ 72,998	N/A	N/A	N/A	$ 72,998
TURN	$ 41,529	N/A	N/A	N/A	$ 41,529
TURN-PG&E	**$ (31,468)**	**N/A**	**N/A**	**N/A**	**$ (31,468)**

II. PG&E Wildfire Risk Modeling

The S-MAP Settlement adopted in D.18-12-014 requires PG&E to engage in rigorous quantitative risk modeling efforts and to present its results in its GRC, which provides useful data for the Commission to consider regarding the reasonableness of PG&E's proposals. The primary output of these extensive efforts is the Risk Spend Efficiency (RSE) metric for each program, calculated as the present value of risk reduction divided by the cost. When calculated correctly with sufficient granularity, RSE is a vital metric for the Commission's evaluation of utility proposals, as it elegantly and succinctly summarizes how risk reduction benefits, including financial, safety, and reliability benefits, compare to a program's costs.[3] In addition, as explained in the accompanying testimony of TURN's expert witness on quantitative risk modeling issues, Jonathan Lesser (TURN-02), RSEs can be readily expressed as benefit/cost (B/C) ratios to enable a dollar to dollar comparison of risk reduction benefits and costs.[4] In general, programs with relatively low RSEs and low B/C ratios should be viewed as blinking red lights to the Commission. Close scrutiny of these programs is required to ensure expenditures are in the public interest and consistent with just and reasonable rates.

The following sections discuss PG&E's wildfire risk modeling efforts and results. We discuss PG&E's lack of affordability and cost-effectiveness criteria to scope its wildfire mitigation program proposals, which lead to sub-optimal proposals included in this GRC. We also find that deficiencies in PG&E's risk modeling clearly indicate that the most effective strategy from a cost and risk reduction perspective is a significant emphasis and focus on compliance with regulatory standards to avoid operational failures.

A. PG&E's Wildfire Risk is Concentrated in a Relatively Small Percentage of HFTD System Miles

As shown in the figures below, PG&E's risk modeling demonstrates that wildfire risk in the utility's service territory is concentrated in a relatively small portion of overhead circuit miles, with 80% of risk contained in the riskiest 10,000 overhead circuit miles out of a total of 25,500 circuit miles[5] in the utility's HFTD. Figure 1 shows PG&E's HFTD miles ranked from highest to lowest risk, with the riskiest 10% of miles shown on the far left side, and the least risky 10% shown on the far right. Both cumulative and incremental miles per 10% tranche are shown (blue bars and orange line, respectively).

Figure 1 shows that only 73 miles, which is less than 0.3% of the total HFTD mileage, contain 10% of the total risk. Further, the riskiest 20% of circuit miles is found over just 480 miles,

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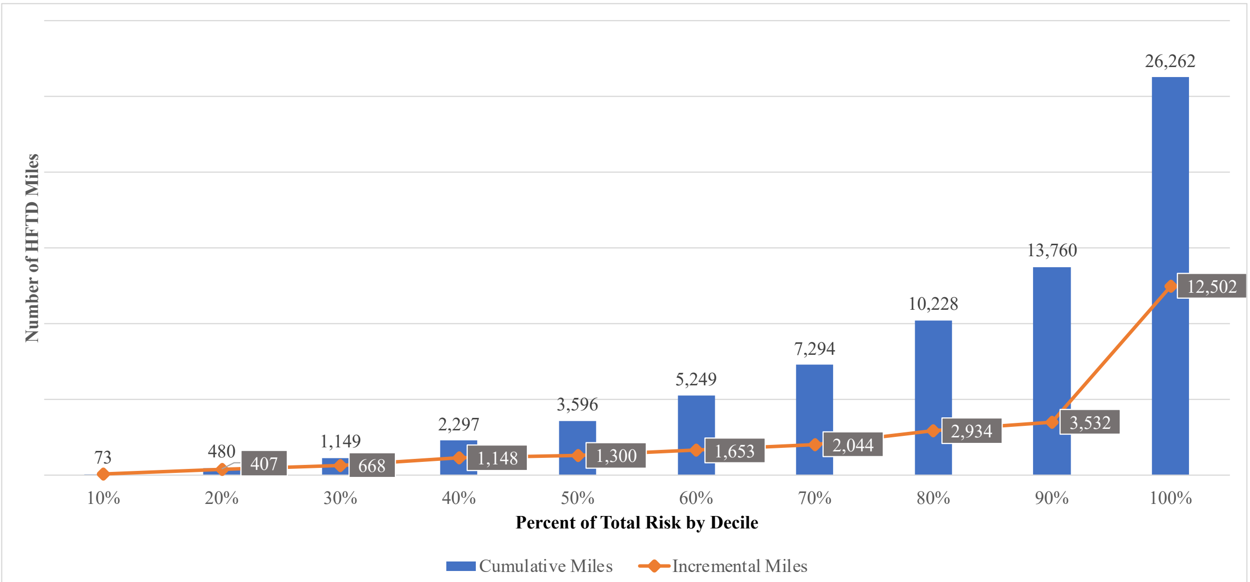
[3] PG&E-2, WP Vol.1, p. WP 1-179.
[4] Ex. TURN-02 (Lesser), Section III.
[5] PG&E Supplemental Testimony, PG&E-4, p. 1-6, line 28. All references to PG&E testimony in this document refer to PG&E-4 unless otherwise noted. This slightly differs from the 26,262 miles shown in PG&E's risk model – PG&E did not explain this discrepancy. See TURN-018, Question 1.

which is less than 2% of total HFTD miles, while the top 30% of risk is contained within only 1,149 miles, or just 4.4% of total HFTD miles.

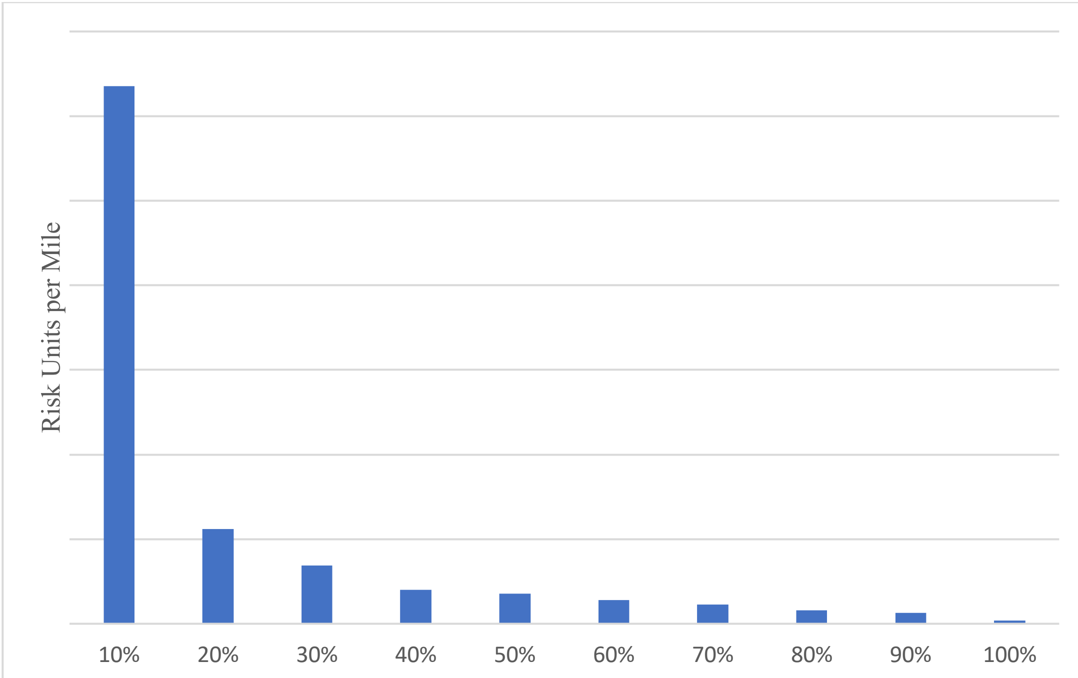
Figure 1. Concentration of Risk in PG&E's HFTD[6]



The concentration of risk can also be seen through examination of the risk per mile in each 10% risk tranche, as shown in Figure 2.

[6] Calculated from TURN-018, Question 1, Attachment 1, which provides total risk at the Circuit Protection Zone level for the Equipment Risk Model. The Equipment Risk Model is the same prioritization model used to calculate tranches for the larger RAMP risk model. The Equipment Risk Model is much more granular, however, than the tranches created for RSE analysis. For example, many Circuit Protection Zones are a mile or less long, while the tranches created are hundreds or, in some cases, thousands of miles long (Excel Risk Workpaper EO-WLDFR-2, Tab "Input_Exposure").

Figure 2. Concentration of Risk in PG&E's HFTD[7]



From this data, we can see that high-cost mitigations should be targeted to the highest risk miles within PG&E's HFTD[8] due to the significantly diminishing risk reduction returns of deploying to relatively low-risk areas.

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[7] *Ibid.*

[8] PG&E finds the approximately 30,000 HFTD circuit miles contain 99% of wildfire risk in the utility's service territory. Excel risk workpaper EO-WLDFR-2_Bow tie, tab Risk Score_Tranche, case TY Baseline Proposed, TY 2023.

B. PG&E's Wildfire Mitigation Proposals Do Not Adequately Incorporate Affordability and Cost-effectiveness Criteria

The overall, program-level RSEs of PG&E's wildfire proposals vary widely, from 0 to 4,043.[9] At the tranche level, variance in RSEs is even more pronounced, ranging from 0 to 28,754.[10] Appendix B to Dr. Lesser's testimony shows the overall, program-level values for all of PG&E's proposed programs (not just wildfire programs), using both PG&E's MAVF and TURN's recommended MAVF, ranked from the highest PG&E RSE to the lowest. In addition, as discussed in Section IV of Dr. Lesser's testimony, the S-MAP Settlement requires PG&E to break down these overall RSEs into values for granular tranches with homogenous risk profiles. As Dr. Lesser explains, appropriately granular RSEs are the most important cost-effectiveness data for determining the appropriate scope of risk mitigation programs, particularly for large-scale capital programs where work is targeted to the highest risk elements of the system first and then proceeds to decreasingly risky system elements.[11] The implications of the cost-effectiveness information that is available in this case are discussed in ensuing sections and utilized throughout this testimony.

Notwithstanding the wealth of cost-effectiveness data that PG&E was required to develop and present in accordance with the S-MAP Settlement, PG&E fails to demonstrate how, if at all, it used this information to decide which wildfire risk mitigation programs to emphasize or how to scope its proposed programs. Although PG&E dutifully presents overall wildfire RSEs in its testimony, PG&E's explanation of which mitigations it chose and how it decided to scope those mitigations does not explain how RSEs, either at the overall or tranche level, influenced those specific choices. For each of its proposed wildfire mitigations, TURN asked PG&E to provide a specific citation to its testimony or workpapers where the company explained how RSE data influenced PG&E's decision regarding the scope of the mitigation to propose. For those mitigations lacking such an explanation, TURN gave PG&E an opportunity to explain how the

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[9] Excel risk workpaper EO-WLDFR-3, tab "RSE Results." Some "foundational" programs do not have associated risk reductions which results in a 0 RSE, while other programs that are relatively costly for relatively little risk reduction have RSEs that are close to 0.

[10] The latter value occurs for one tranche of PG&E's routine vegetation management program. Excel risk workpaper EO-WLDFR-3, tab "RSE Results."

[11] Ex. TURN-02 (Lesser), p. 48.

RSE data influenced its decision-making. In response, PG&E failed to provide any specific citations for any wildfire mitigations and instead focused its answer on considerations *other than RSE* that it used in deciding the scope of mitigations to propose.[12] While PG&E will hopefully use its risk modeling and related results to *prioritize its work* after it is authorized – i.e. to guide deployment of a given mitigation from highest to lowest risk area – it is clear from TURN's review that PG&E's modelling efforts have not been used for the purpose of forming its wildfire mitigation proposals.

Consistent with its failure to utilize the cost-effectiveness data required by the S-MAP Settlement in making decisions regarding its specific wildfire mitigation proposals, PG&E admits that it did not consider any upper bound for spending, stating: "**There were no specific "affordability constraints" used to determine the appropriate overall level of wildfire mitigation expenditures.**"[13] Only a monopoly has the ability to pass on huge increases in costs regardless of whether they can be afforded by its customer base and without careful consideration of cost-effectiveness. Access to affordable energy, as an essential service, has its own safety implications if not available in sufficient quantities at an affordable price. While PG&E states it agrees that "mitigation measures should generally seek to maximize the amount of risk reduction for the least amount of ratepayer dollars," it confounds this relatively unobjectionable sentiment by stating "there are multiple considerations and complexities to implementing that [goal]."[14] PG&E's broad-based effort to deploy the most expensive single mitigation – undergrounding – is simply not consistent with due regard for cost-effectiveness and customer affordability.

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[12] TURN-195, Question 1. The only citation PG&E gives is to Ex. PG&E-4, "starting at p. 2-18", which appears to reference a general three-page discussion under the heading "Prioritizing Funding in the 2023 GRC" that never mentions RSE and does not discuss how RSE data influenced decision-making regarding any specific mitigation.
[13] TURN-4, Question 10(d).
[14] TURN-4, Question 10(e).

C. The Vast Majority of Wildfire Risk Can be Mitigated Through Programs that Ensure Regulatory Compliance

One of the striking conclusions from a review of PG&E's use of risk modeling results in its GRC proposals is how it neglects the role of basic compliance with state law as the single most effective way to reduce its wildfire risk. This is generally accomplished through what PG&E terms "control" programs, activities that have been in place for several years, and often decades, usually to meet regulatory requirements.[15] By contrast, PG&E describes "mitigations" as programs that exceed compliance mandates or are unrelated to compliance with existing regulations, such as undergrounding and enhanced vegetation management.[16]

As seen in the Figure below, based on the present value of risk reduction for all years in which a program provides risk reduction (e.g. 50 years for undergrounding) at least **98%** of risk reduction will come from "control" programs – vegetation management (routine and tree mortality), equipment maintenance and replacement, and pole replacement.[17]

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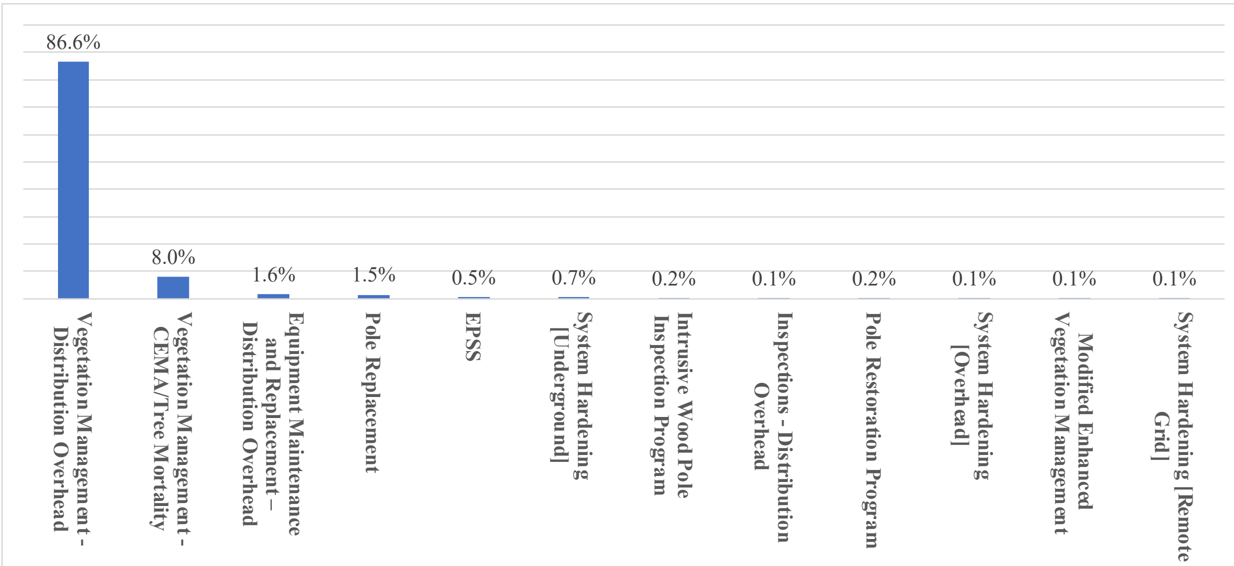
[15] See TURN-4, Question 11, Attachment 1. All programs that seek to meet regulatory requirements are "controls," however it is not the case that all control programs are associated with specific regulations. That said, most are related to basic maintenance of PG&E's system and what TURN would consider "compliance" with regulatory standards.

[16] See TURN-4, Question 11, Attachment 1. PG&E also includes programs it deems "foundational controls" which are "part of PG&E's best internal practices and procedure." "Foundational mitigations" are programs not associated with specific compliance requirements. No mitigation was associated with a specific compliance requirement according to PG&E.

[17] Comparison of NPV risk reduction for all years for controls and mitigations respectively, divided by total risk reduction, based on data from TURN-053, Question 2, Supplemental 1, Attachment 1.

Figure 3. NPV Risk Reduction from Controls vs. Mitigations (%)
2023 Through End of Program Benefits



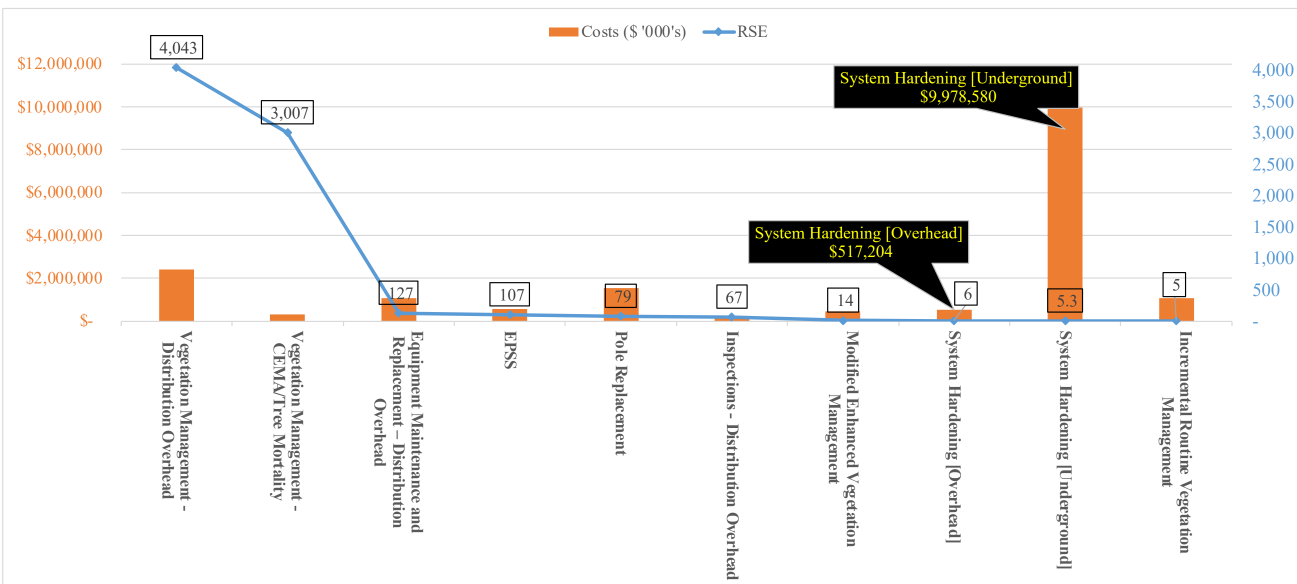
TURN acknowledges that PG&E's methodology, and thus the Figure above, does not allow for a straightforward way to compare absolute risk reduction for controls and mitigations on an apples-to-apples basis. This is due to a modeling limitation that PG&E states prohibits it from calculating risk reduction on a "portfolio" basis for controls, a methodology which accounts for overlap in program scope (this can only be done for mitigations, according to PG&E).[18] The calculation above uses risk reduction figures calculated with what PG&E calls the "incremental" basis, which does not account for program overlap[19] and thus overstates risk reduction for both controls and mitigations. Nevertheless, the relative magnitude of risk reduction between controls and mitigations is instructive and is not likely to appreciably change if use of the "portfolio" method could be employed for all programs.

To be clear, TURN does not oppose efforts to exceed regulatory compliance standards, and indeed we do not call for the complete elimination of any wildfire mitigation program proposal in this GRC. We do oppose, however, PG&E's inability to incorporate a modicum of affordability and cost-effectiveness into its wildfire mitigation proposals. Indeed, <u>68%</u> of the

[18] TURN-053, Question 2, Footnote 1.
[19] PGE-2, p. 1-21, lines 10-13.

almost \$20 billion PG&E has proposed for 2023-2026 wildfire proposals are dedicated to "mitigations" as opposed to "controls,"[20] despite the fact that, in general, the latter are the most cost-effective and broad-based (i.e. deployed across the entire HFTD) programs to reduce wildfire risk. This is seen in the following figure, which shows the RSE (blue line) and expenditure (orange bar) for the largest proposed programs (by total cost).[21] The programs are ordered from left to right from highest RSE to lowest RSEs. Other than EPSS, the programs toward the left of the figure with highest RSEs are control programs; to the right are significantly less cost-effective mitigations like undergrounding.

Figure 4. RSEs and Costs of Wildfire Mitigation Programs[22]
2023-2026



Despite the fact that routine vegetation management has a high forecast cost of \$2 billion over the GRC period, it has an RSE that is 689-760 times higher than the overhead and underground system hardening programs, respectively. Put simply, the risk reduction for system hardening is

[20] Calculated from Excel risk workpaper EO-WLDFR-3, tab "2-Program Cost."
[21] These programs represent 96% of the 2023-2026 proposed wildfire mitigation costs.
[22] Excel risk workpaper EO-WLDFR-3, tabs "2-Program Cost," "RSE Results." The Figure shows the top 15 wildfire mitigation programs, which comprise 96% of total spending. Cost figure for system hardening underground include Community Rebuild costs.

relatively low in comparison with the very high proposed costs, particularly when compared with compliance-related programs like vegetation management.

D. Correctly Defining the Risk Driver "Operational Failure" Has a Large Effect on PG&E's Risk Modeling Results and Illustrates Why Compliance with Legal Requirements, by Itself, Would Significantly Reduce PG&E's Wildfire Risk

Based on analysis of ignitions in PG&E's service territory from 2015-2020, by far the most significant driver of the largest and most devastating utility-caused wildfires is lack of compliance with regulatory standards. Indeed, of the seven "catastrophic"[23] and two "destructive"[24] wildfires ignited by PG&E equipment over this six-year period, **100%** have been found by a governmental agency to be the result of a violation of one or more regulatory requirements, discussed further below.[25]

From a risk modeling perspective, ignitions caused by compliance failures – for example not maintaining equipment or trimming trees to mandatory clearances - should be attributed to a risk driver called "operational failure," or a similar term to capture failure to comply with regulatory requirements. However, PG&E failed to accomplish this; instead, the utility defines the operational risk driver narrowly as a "workforce-caused outage"[26] which it states are "events where failure to follow a process or procedure was a significant contributor to the event."[27] More specifically, to qualify as an operational failure under PG&E's definition, the "basic cause" field in PG&E's ignition database must be listed as "company initiated," whereby a later review by PG&E finds the ignition was due to a "human failure."[28]

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[23] A catastrophic wildfire is defined by PG&E as "a fire that destroys 100 or more structures and results in a serious injury and/or fatality." See PGE-2, WP Vol 1, p. WP 1-412, lines 6-7.

[24] A "destructive" wildfire is defined by PG&E as "A fire that destroys 100 or more structures but does not result in a serious injury or fatality." PGE-2, WP Vol 1, p. WP 1-412, lines 8-9.

[25] TURN lists the fires that were found to be the results of compliance failures by SED and CalFire in TURN-97, Question 1, Table 1-1. These were matched to PG&E's categorization of ignitions (e.g. "catastrophic", "destructive", etc.) in TURN-97, Question 1, Supplemental 2, Attachment 1. CalFire forwarded its investigative report regarding the Zogg Fire to county prosecutors (https://www.fire.ca.gov/media/u2kh4nyd/zogg-fire-press-release.pdf), which typically means that CalFire found that utility violations were involved in causing the fire.

[26] PG&E Supplemental Testimony, p. 3-23, line 10.

[27] TURN-004, Question 8d.

[28] TURN-004, Question 8b.

Contrary to a common-sense definition and application of "operational failure" to categorize historical ignitions, PG&E admits that "ignitions that are related to instances of violation of compliance requirements do not automatically fall under "operational failure" under this methodology."[29] As a clear example of why this is inappropriate, the 2018 Camp Fire, which was found to be caused by compliance failures, and to which PG&E pleaded guilty to 84 felony counts,[30] is not considered by PG&E to be an "operational failure." Instead, it is categorized as just another "equipment failure,"[31] which does not recognize PG&E's clear managerial and programmatic failures that contributed to the inability to recognize that PG&E's equipment was about to fail.

TURN analyzed the wildfires in PG&E's service territory from 2015-2020, finding that all seven ignitions caused by PG&E that were "catastrophic" under PG&E's definition have been found by a governmental entity (e.g. SED or CalFire) to be due to what TURN would categorize as an "operational failure," namely a failure to comply with regulatory requirements.[32] Similarly, the two "destructive" wildfires ignited by PG&E equipment from 2015-2020 were found to involve compliance failures.[33]

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[29] TURN-004, Question 8h.
[30] ABC News, *PG&E Pleads Guilty to charges stemming from 2018's Camp Fire,* https://www.abc10.com/article/news/local/wildfire/pge-gulity-plea/103-9c9aad82-1796-48a2-a797-544a5ad39907#%3A~%3Atext=The%20California%20power%20company%20plans,for%20more%20than%20a%20century.
[31] TURN-004, Question 8g.
[32] See TURN-97, Question 1, Supplemental 2, Attachment 1, tabs "CPUC Reportable (Sensitivity)" and "Table 1-1 Mapping." TURN lists the fires that were found or alleged to be the results of compliance failures by SED or CalFire in TURN-97, Question 1, Table 1-1. (As noted above, based on past experience, CalFire's referral of its Zogg Fire investigative report to county prosecutors means that CalFire found legal violations). The following were listed in PG&E's workpapers as catastrophic wildfires: Zogg, Butte, Cascade, Redwood Valley, Nuns, Atlas and Camp Fire. Two fires in PG&E's database have a listed cause of "electrical power" but were caused by customer equipment and are therefore not relevant to PG&E's wildfire mitigation strategy or risk analysis. These were the Valley Fire, caused by faulty residential wiring and the Tubbs Fire, which was caused by a "private electrical system." See ABC 7 News, https://abc7news.com/valley-fire-was-caused-by-a-faulty-residential-electrical-connection-in-lake-county-evacuees-homeless-victims/1464779/, and CalFire, https://www.fire.ca.gov/media/5124/tubbscause1v.pdf.
[33] The Sulphur (Mendocino Lake Complex) in 2017 and Kincade Fire (2019). See TURN-97, Question 1, Supplemental 2, Attachment 1, tabs "CPUC Reportable (Sensitivity)" and "Table 1-1 Mapping."

Based on a more reasonable definition and application of "operational failure" to include ignitions that were the result of compliance failures like the Camp Fire (and then otherwise using PG&E's methodology for assigning risk to drivers), we calculate that **99.7%** of wildfire risk should be attributed to the "operational failure" driver,[34] as opposed to .1% of risk under PG&E's narrow definition and attribution methodology.[35] This result is due to the overwhelming impact that the most devastating wildfires have on overall wildfire risk, even though they are relatively infrequent. Accurately recognizing the role of operational failure as the key driver of PG&E's wildfire risk has a significant effect on the risk modeling results and RSE of every wildfire mitigation proposed by PG&E, significantly decreasing the cost-effectiveness values for mitigations like overhead and underground system hardening. In turn, properly recognizing the outsize contribution of the operational failure driver to PG&E's wildfire risk means that any program to improve compliance programs, such as enhanced Quality Assurance and Quality Control (QA/QC), would have significantly higher cost-effectiveness values than under PG&E's current modeling, particularly as these appear to be necessary for PG&E to implement its control programs with a high degree of competence. These impacts are discussed and quantified in Section VI of the testimony of TURN's expert witness on quantitative risk modeling issues, Dr. Lesser.

The importance of reducing wildfire risk through control programs and QA/QC to increase the implementation quality of these programs is reinforced by the May 26, 2022 Revision Notice issued by the Office of Energy Infrastructure Safety (OEIS) in relation to PG&E's 2022 Wildfire Mitigation Plan (WMP). OEIS determined that PG&E has "demonstrat[ed] a low quality of asset inspections and . . . has not provided adequate details on its plan to improve asset inspection quality moving forward."[36] OEIS pointed to high QA/QC "find" rates (reviews in which discrepancies were identified) between 5 and 58 percent and "an alarmingly high failure rate"

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[34] Calculated from TURN-97, Question 1, Supplemental 2, Attachment 1. This can also be seen in Excel risk Workpaper EO-WLDFR-2_Bow Tie, "Conseq" tab, rows 10-14, in which 99.7% of wildfire risk is attributed to "catastrophic" and "destructive" wildfires, all of which, as discussed, were found by government investigators to have resulted from compliance violations.

[35] PG&E Supplemental Testimony (Ex. PG&E-04) , p. 3-24, Figures 3-2 and 3-3; Excel Risk Workpaper "EO-WLDFR-2_Bow Tie," tab "Bow Tie." PG&E refers to the driver in the bow tie as "Utility Work / Operation."

[36] OEIS Revision Notice for PG&E's 2022 WMP Update, May 26, 2022, p. 19 (footnote omitted).

(when "a compelling abnormal condition" was missed) between 8.5 and 33 percent.[37] As OEIS aptly explained, "if potentially hazardous conditions are not identified correctly, there is a heightened risk that those assets could cause ignitions before they can be identified."[38]

PG&E states in its RAMP filing that “PG&E’s risk management focus is on reducing catastrophic events with potentially extreme consequences.”[39] Yet rather than laser focus on remedying the primary cause of catastrophic and destructive wildfires caused by PG&E equipment – operational failure, i.e. lack of compliance with regulatory standards - PG&E proposes to focus its risk mitigation efforts on by far the most costly mitigation it has at its disposal, undergrounding its power lines. The implication of PG&E’s undergrounding plan is to make ratepayers pay extremely large and unaffordable sums to underground its lines so the utility can protect against ignitions that can be much more cost effectively avoided merely by fulfilling its legal obligations. While TURN’s proposal errs on the side of caution by proposing additional large investments in more cost-effective, non-compliance mitigations, primarily replacement of bare conductor with covered conductor, the Commission should keep in mind that substantial and cost-effective risk reduction can be achieved simply by improving PG&E’s compliance with the law.

III. PG&E Wildfire Mitigations

PG&E proposes extraordinary ratepayer costs of $20 billion for 44 wildfire mitigation programs[40] over the GRC period (2023-2026), the largest of which is the undergrounding of approximately 3,300 miles of distribution lines. The top 15 programs are shown below, representing 96% of proposed wildfire mitigation costs.

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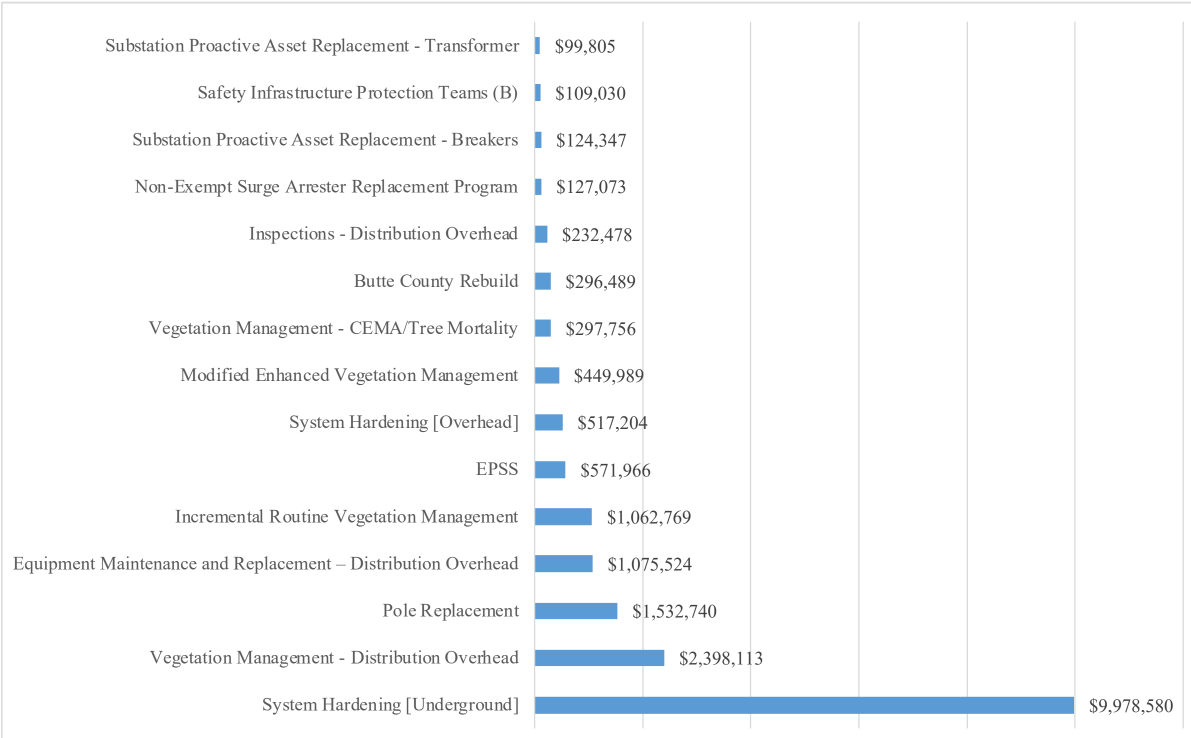
[37] *Id.*
[38] *Id, pp. 19-20.*
[39] PGE-2, WP Vol 1, p. WP 1-219, lines 18-20.
[40] Excel Risk Workpaper EO-WLDFR-3_ RSE Input File, tab “Program Cost.”

Figure 5. PG&E Proposed Largest Wildfire Mitigation Programs and Costs 2023-2026 ($ Thousands)[41]



TURN's testimony focuses on the system hardening overhead and underground proposals.[42] We demonstrate that significantly scaling back the undergrounding program to target the very highest risk miles while scaling up the deployment of covered conductor is a more cost-effective approach to wildfire mitigation; in conjunction with well-implemented compliance programs, this strategy will significantly drive down risk and ensure rates do not escalate even more than the current high levels.

A. Overview of System Hardening

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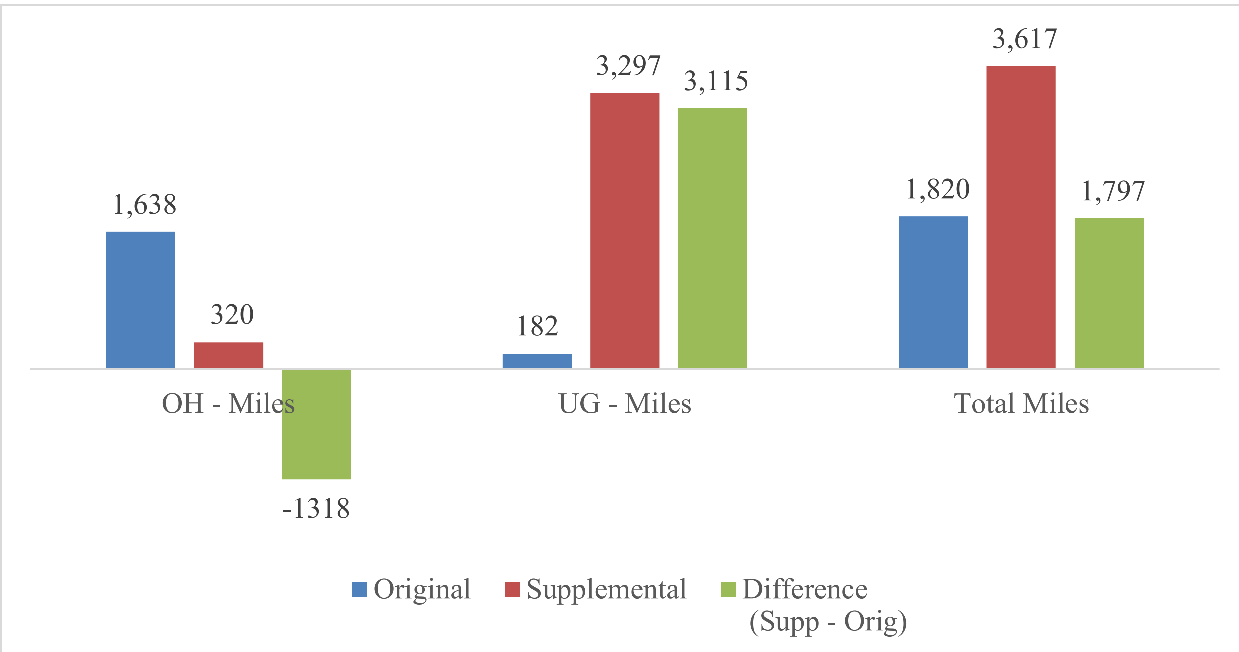
[41] Excel Risk Workpaper EO-WLDFR-3_ RSE Input File, tab "Program Cost." Due to resource limitations, TURN does not address all wildfire mitigations presented in this GRC. It should be noted that we do not *wholly* oppose any wildfire mitigation measure proposed by PG&E, and as described above, find that compliance activities implemented well are the most effective mitigation measures to reduce PG&E's wildfire risk.

[42] I do not address Community Rebuild costs included as part of system hardening. These are addressed in TURN Witness Robert Finkelstein's testimony (TURN-13).

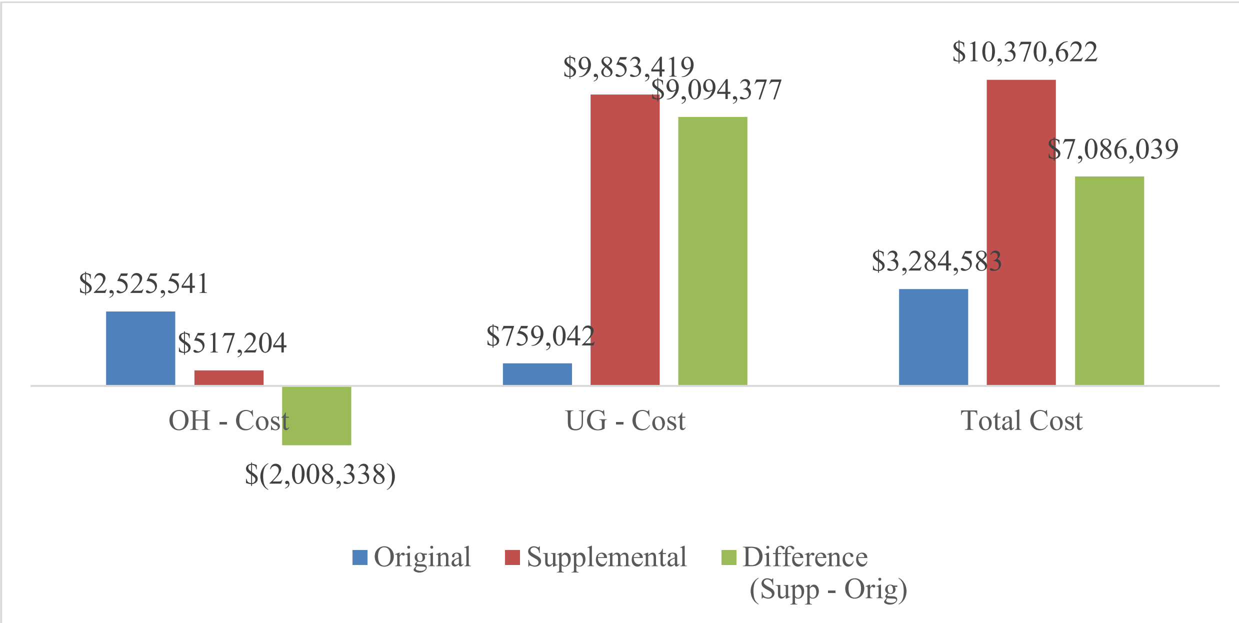
PG&E's System Hardening (SH) proposal consists of two primary programs – overhead conductor replacement and undergrounding power lines. While PG&E's original June 2021 testimony focused efforts and costs on the utility's overhead hardening program, the February 2022 Supplemental Testimony shifts almost entirely to undergrounding, and increases the total number of miles to be "hardened." This results in a larger SH program for both miles and costs, an increase of 1,800 miles and $7 billion, respectively, as illustrated graphically below.[43]

Figure 6. PG&E Original Filing vs. Supplemental Miles (2023-2026)



[43] These statistics and ensuing Figures compare WP Table 4-23 from PG&E's original filing to its supplemental. They do not include Community Rebuild forecast miles or costs (which did not change between the two filings).

Figure 7. PG&E Original Filing vs. Supplemental
Costs (Nominal, 2023-2026, $ Thousands)



PG&E's supplemental testimony also modifies the unit costs for its undergrounding program, ostensibly decreasing the forecast unit cost from around $4.1 million per underground circuit mile per year to $3.3 million to $2.8 million per year from 2023-2026.[44]

PG&E's $10.3 billion system hardening proposal, primarily to underground 3,300 miles of distribution lines at a cost of $9.9 billion, requires significant scrutiny, and should be evaluated with a high degree of skepticism. While TURN acknowledges that undergrounding lines has the highest mitigation effectiveness and should be utilized as a specialized tool to reduce the risk of ignition on the highest risk circuits, it also comes with by far the highest cost, complexity, and deployment risk of any program. PG&E has no proven track record of implementing a program of the size and complexity as the one proposed here in an efficient, effective, and risk-informed manner, and TURN has seen no information or evidence in support of PG&E's Application to ameliorate these concerns (see discussion below).

[44] WP Table 4-23. I say "ostensibly," because PG&E's proposed ratemaking results in a significantly higher "reasonableness" unit cost threshold of $3.5-$4.2 million per underground circuit mile.

PG&E's filings in this case clearly demonstrate that cost, affordability, and cost-effectiveness were simply not significant considerations when PG&E formulated its wildfire mitigation proposals. From a public interest perspective, however, these are critical, as they grapple with the key policy question of how to balance the imperatives of safety and affordability. PG&E's disregard for the affordability of electric rates imperils the ability of already strapped ratepayers to pay for basic necessities, and impedes state electrification goals, which depend on the financial viability of electricity as a fuel for building appliances and vehicles.

While TURN does not oppose aggressive actions to mitigate the threat of utility-caused wildfires, these should not supplant the utility's obligation to deploy its core compliance programs for which it has been funded by ratepayers for decades, and which are the most cost-effective solutions to wildfire mitigation (see Section II.C above). Anything beyond this should be cost-effective, strategic, and targeted. An ill-developed plan for 10,000 miles of undergrounding at exorbitant cost to ratepayers does not meet these fundamental criteria.

B. System Hardening – Overhead

PG&E's System Hardening Overhead (OH) program consists of replacing bare conductor with covered conductor, replacing existing poles with new poles, replacing certain non-exempt equipment, replacing existing transformers with transformers that contain FR3 fluid, replacing crossarms, framing and animal protection upgrades, and vegetation clearing.[45] PG&E forecasts unit costs of $1.6 to $1.7 million per overhead mile from 2023-2026. PG&E forecasts 170 miles of overhead hardening in 2023, but only 50 miles per year for 2024-2026 as the utility focuses on its undergrounding efforts.[46] PG&E finds that overhead system hardening "can often be done more quickly" than undergrounding projects[47] and expects OH system hardening to have a high mitigation effectiveness (risk reduction), second only to undergrounding.

TURN's analyses in the ensuing sections demonstrate that a more limited scope of covered conductor work that eliminates unnecessary asset replacement is 53% less costly than PG&E's

[45] PG&E Supplemental Testimony, p. 4.3-45-46.
[46] WP Table 4-23.
[47] PG&E Supplemental Testimony, p. 4.3-44, lines 16-17.

program, while providing 93% of the safety benefits compared with PG&E's full system hardening overhead scope. TURN thus recommends 450 miles per year of covered conductor deployment from 2023-2026 at a unit cost beginning at around $800,000 per mile. The 1,800 miles proposed by TURN over the GRC period is a 463% increase over PG&E's current proposal and a 10% increase over PG&E's original proposal.[48]

1. TURN Estimate of the Unit Cost of Covered Conductor Deployment

As TURN has explained in prior testimonies,[49] PG&E's OH program replaces various assets in addition to the bare conductor and supporting infrastructure like poles and crossarms, thus significantly increasing the unit cost of this program. This can be seen most directly by comparing the forecast unit costs of PG&E's program with Southern California Edison's (SCE's) actual recorded covered conductor deployment costs – around $1.6 million per mile for PG&E versus $629,000 per mile for SCE in 2021.[50]

PG&E has consistently refused to segregate out the costs it has incurred to install covered conductor versus to replace other components of its OH SH program, stating that it does not track this statistic.[51] TURN therefore estimated the unit (dollar per overhead mile) cost of a more limited scope of work for covered conductor installation in TY 2023 by using PG&E recorded units and cost data, as well as increased transparency regarding pole replacement as part of PG&E's system hardening program agreed upon in the 2020 GRC settlement as follows:

1. Starting with the unit cost to replace bare conductor with new bare conductor, including some pole replacements,[52] we add the cost of incremental pole replacements and additional installations due to CC in PG&E's 2020 system hardening program (we assume 100% of poles are replaced due to CC)[53] using 2020 unit costs.[54]

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[48] Calculated from WP Table 4-23 (Supplemental and original).
[49] See TURN testimony in PG&E TY 2020 GRC (A.18-12-009), pp. 19-23; PG&E 2019 Wildfire Memorandum Account Reasonableness Review (A.20-09-019), pp. 16-24.
[50] SCE WMP Filing, Excel Table 12, row 30. Subtracts stated deployment of non-WCCP CC deployment.
[51] TURN-007, Question 4.
[52] WP Table 13-12. Pole replacements from TURN-50, Question 14.
[53] Poles replaced per mile from PG&E Pole Replacement Report, Prepared Pursuant to 2020 GRC Settlement, Transmitted to TURN on October 11, 2021 ("Pole Replacement Report"), including all poles.
[54] WP Table 12-22, line 14.

2. We add to this the additional material costs of covered conductor compared with bare wire.[55] This provides an estimated cost per mile for covered conductor in 2020.

3. We then subtract pole replacement costs not expected to be incurred in 2023 based on the average number of poles in PG&E's HFTD[56] plus 20% for additional poles to be installed to shorten spans based on recorded SH program data.[57]

4. We subtract expected savings from lower pole replacement costs forecast by PG&E in 2023 relative to 2020.[58]

5. We incorporate escalation[59] and the cost to replace non-exempt fuses,[60] which TURN does not oppose as part of SH scope.

TURN's unit cost estimate provides sufficient budget to replace bare conductor with covered conductor, replace 100% of poles, install additional poles to potentially shorten spans where this is needed to support the additional weight of covered conductor, and replace all non-exempt fuses. TURN's calculations thus eliminate the costs of replacing transformers, animal protection upgrades, reclosers, switches, surge arrestors, and voltage regulators,[61] which are not necessary to deploy covered conductor.[62] This results in a unit cost of about $800,000 per overhead circuit mile in TY 2023, as shown below.

[55] Average covered conductor materials cost from TURN-50, Question 13, Rev01 less TURN-50, Question 12, Rev01 average, adjusted for the number of conductors per phase (2.33) from TURN-187, Question 2, Attachment 1.
[56] TURN obtained the number of poles by Circuit Protection Zone (CPZ) in TURN-50, Question 1, Attachment 1. These were then apportioned to HFTD by multiplying the number of poles by the percentage of miles in HFTD of the CPZ. Average is total number of poles in HFTD / total HFTD miles in the model (provided in TURN-018, Question 1, Attachment 1), 26,262 miles.
[57] Based on actual number of poles replaced (4,275) versus installed (5,072) in PG&E's 2020 System Hardening Overhead Program, provided in the Pole Replacement Report. 5,072 / 4,275 = 1.19, rounded to 20% increase.
[58] WP Table 12-22.
[59] WP Table 2-20.
[60] Number of fuses per CPZ from TURN-006, Question 1, Attachment 1. Apportioned to HFTD based on number of miles in each CPZ in HFTD from TURN-018, Question 1, Attachment 1. Fuses per HFTD mile multiplied by cost per fuse replacement in 2023 from WP Table 4-25, line 17.
[61] See TURN Testimony submitted in A.20-09-019, Appendix 1, and DR TURN-009, Question 7, Attachment 1 from the same proceeding, included in the attachments to this testimony.
[62] TURN includes in its scope costs to replace non-exempt fuses, as we do not oppose this aspect of PG&E's system hardening program. See Table below.

Table 2. Forecast Unit Cost of Covered Conductor ($/Mile)[63]

Cost Category	Dollar Per Mile
2020 Bare Conductor Replacement Cost	$ 563,545
2020 Additional Pole Replacement for Covered Conductor	$ 437,815
Additional Materials Cost	$ 15,446
2020 Covered Conductor Cost	**$ 1,016,806**
Less: Pole Replacements	$ 224,667
Less: Pole Replacement Cost in 2023 Relative to 2020	$ 42,524
Expected Covered Conductor Cost ($2020)	**$ 749,616**
Add: Escalation ($2023)	$ 789,870
Add: Cost of Fuses	$ 5,963
Cost of Covered Conductor TY 2023 ($/Mile)	**$ 796,000**

TURN's unit cost estimate provides a premium of 26% over SCE's recorded 2021 unit costs to deploy covered conductor.[64] In a previous reasonableness review proceeding, TURN's expert used a different methodology, estimating around $700,000 per mile.[65] TURN's estimate is more than adequate to allow PG&E to replace bare conductor with covered conductor and non-exempt fuses, including all necessary pole installations and pole replacements.

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[63] See the written section above and related citations for the source of this information.
[64] $629,000/mile. SCE WMP Filing, Excel Table 12, row 30. Subtracts stated deployment of non-WCCP CC deployment.
[65] This did not include the cost of fuses. TURN Direct Testimony in A.20-09-019, Appendix 1, included as an attachment to this testimony.

2. TURN's More Narrow Scope for Covered Conductor Installation Provides Nearly All of the Safety Benefits of PG&E's System Hardening Overhead Program

PG&E estimated the mitigation effectiveness of its SH OH program by "analyzing projected performance of overhead hardened facilities on more than 4,600 outage types,"[66] finding that "overhead system hardening will reduce 62 percent of the distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines, such as vegetation tree strikes."[67] PG&E's analysis considered the impact of each of the different assets PG&E intends to replace as part of its OH SH program.

As described above, TURN recommends that system hardening overhead work not include replacement of useful assets that do not pose significant ignition risk (see below) and are not necessary to replace for the installation of covered conductor. In order to estimate the mitigation effectiveness of our proposed scope of work for covered conductor, TURN utilized the same methodology as PG&E, but adjusted for TURN's OH scope, by eliminating or reducing any contributions to wildfire risk resulting from equipment which TURN believes need not be replaced as part of covered conductor installation. A full description of TURN's analysis is provided in Appendix 3 to this testimony, sponsored by Curt Volkmann, an electrical engineer with 38 years of experience in the utilities industry. The analysis finds that TURN's scope provides 93% of the ignition reduction benefits of PG&E's SH OH program scope.

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[66] PG&E Supplemental Testimony, p. 4.3-44, lines 19-20.
[67] PG&E Supplemental Testimony, p. 4.3-44, lines 20-23.

Table 3. Mitigation Effectiveness of Overhead System Hardening Program
PG&E vs. TURN[68]

Driver	Average of PG&E Effectiveness (%)	Average of TURN Effectiveness (%)
Animal	79%	67%
D-Line Equipment Failure	69%	56%
Human Performance	0%	0%
Natural Hazard	33%	26%
Other	90%	90%
Other PG&E Assets or Processes	14%	0%
Third Party	58%	58%
Vegetation	62%	60%
Wildfire Mitigation	70%	70%
Grand Total	**61.8%**	**57.6%**

TURN Scope vs. PG&E (% of Benefits)	**93%**

3. TURN's Recommendation to Focus Primarily on Covered Conductor is More Cost-effective than PG&E's System Hardening Overhead and Underground Programs

PG&E finds that overhead system hardening "can often be done more quickly" than undergrounding projects[69] and expects OH system hardening to have a fairly high mitigation effectiveness, second only to undergrounding. PG&E finds that OH system hardening is a more cost-effective solution when compared with undergrounding:

> PG&E projects that overhead system hardening will reduce 62 percent of the distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines, such as vegetation tree strikes. **This alternative generally has a higher RSE when compared to the undergrounding alternative in many scenarios**.[70]

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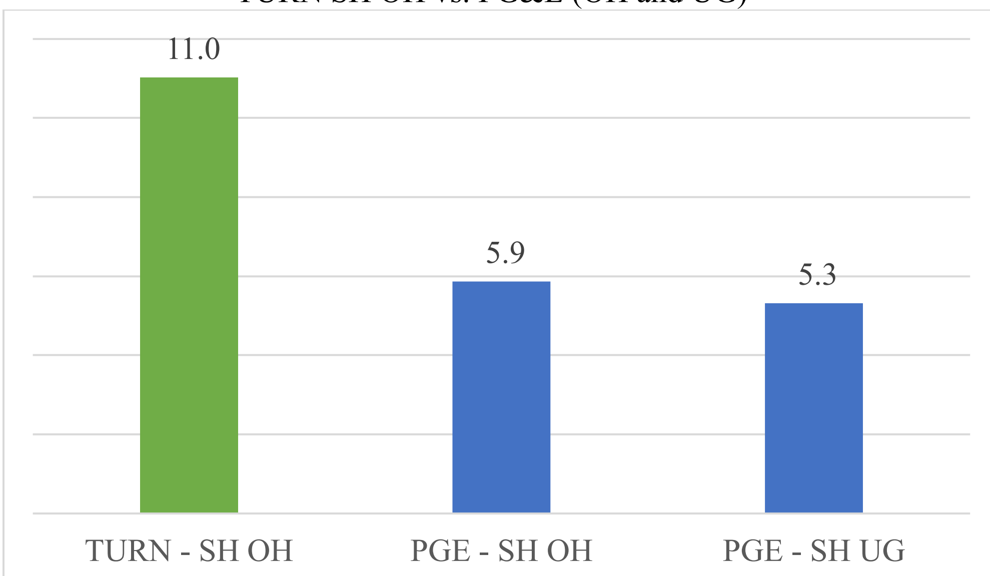
[68] See Appendix 3 for a full description of TURN's methodology and assumptions, which mirrors PG&E's other than assuming a different scope of program. Calculations from TURN-007, Question 2, Attachment 1.
[69] PG&E Supplemental Testimony, p. 4.3-44, lines 16-17.
[70] PG&E Supplemental Testimony, p. 4.3-44, lines 20-24.

TURN agrees with PG&E that overhead installation of covered conductor is a more cost-effective approach to mitigating ignition risk, as indicated by a higher risk spend efficiency score. The results are even more striking when the scope of overhead hardening is reduced by eliminating unnecessary asset replacements, as in TURN's proposed scope. This is demonstrated through a comparison of the RSE statistic for TURN's recommendation compared with PG&E's overhead and underground proposals, shown below.[71]

Figure 8. Risk Spend Efficiency - Overall
TURN SH OH vs. PG&E (OH and UG)[72]



TURN's recommendation is also more cost-effective at the individual tranche level, shown below.

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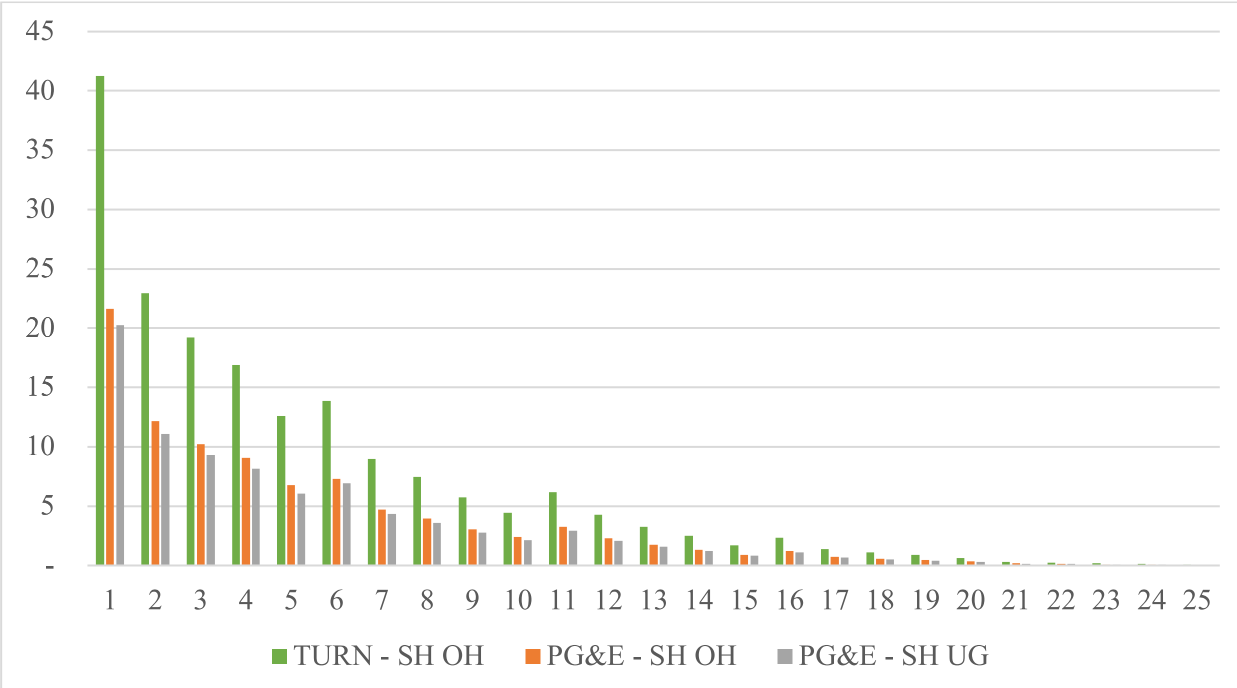
[71] In the following two figures, all of the RSEs are based on PG&E's MAVF, not the TURN recommended MAVF, related to wildfire risk. For the reasons discussed in Section II.D of Dr. Lesser's testimony for TURN, using TURN's MAVF generally results in lower RSE values. For example, in Section IV of his testimony, Dr. Lesser presents a table showing that the overall and tranche level RSEs for SH UG are approximately 10% lower under TURN's MAVF than under PG&E's MAVF. Dr. Lesser also discusses why PG&E's WF RSEs are overstated due to inadequate incorporation of "operational failure" as a driver – see discussion in Section II.D above and TURN-02 (Lesser), Section VI. We note, however, that this deficiency would not affect the *relative* cost-effectiveness of the various programs, as illustrated here.

[72] Calculated from TURN-7, Question 10, Supp01, Attachment 1. TURN incorporated its estimates of mitigation effectiveness and unit cost of covered conductor into PG&E's calculation to derive RSE estimates at the overall and tranche levels.

Figure 9. Risk Spend Efficiency – Tranche Level
TURN SH OH vs. PG&E (OH and UG) [73]



When evaluated based on the percentage of risk contained in each area of PG&E's HFTD, as illustrated previously in Figures 1 and 2, TURN's proposed scope of deployment of covered conductor results in addressing the top 60% of risk over the next ten years due to the deployment of undergrounding and covered conductor, as illustrated below using PG&E's current risk model results:[74]

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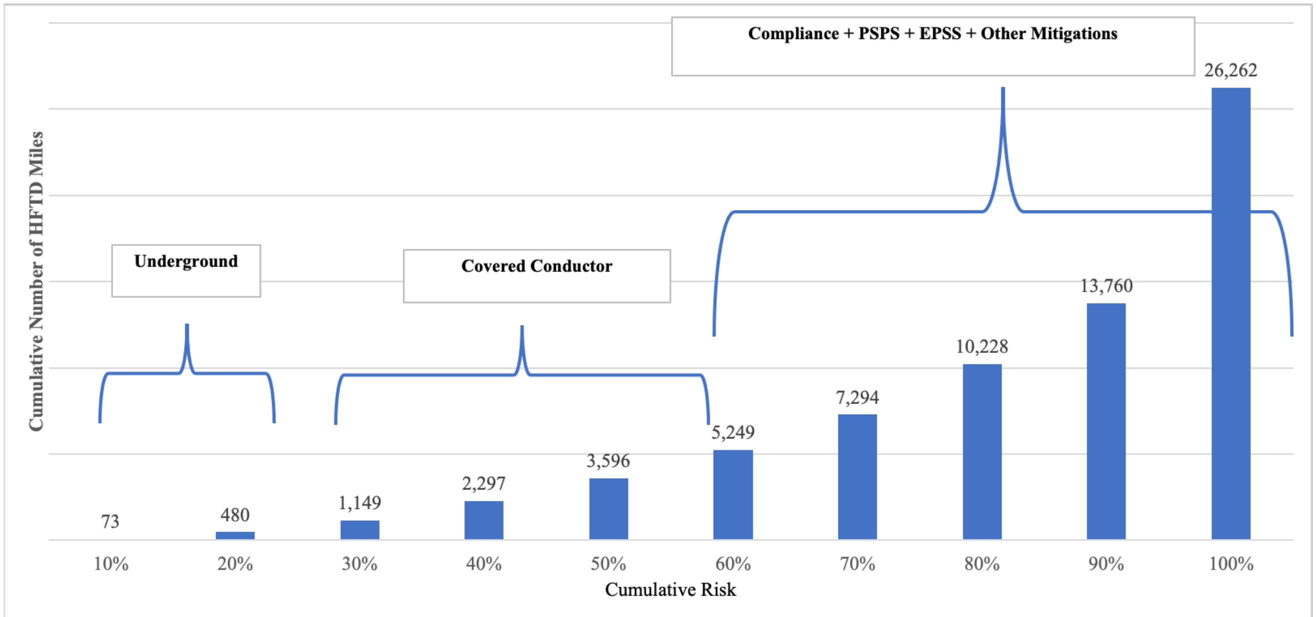
[73] Calculated from TURN-7, Question 10, Supp01, Attachment 1. TURN incorporated its estimates of mitigation effectiveness and unit cost of covered conductor into PG&E's calculation to derive RSE estimates at the overall and tranche levels.

[74] See Figure 1~~Figure 1~~ and preceding discussion.

Figure 10. Illustrative 10-Year Deployment Plan Based on PG&E Current Risk Model and TURN Proposal



TURN thus recommends significantly greater focus on covered conductor deployment than PG&E's proposal, as it is more cost-effective and can play a large role to drive down risk over the GRC period. in addition to targeted undergrounding to the highest risk, most cost-effective lines. TURN's recommendation is to deploy 1,480 more miles of overhead system hardening, focused primarily on covered conductor, for $975 million more than PG&E's proposal over the GRC period.

Table 4. PG&E vs. TURN System Hardening Overhead Cost Comparison ($ Thousands)[75]

	2023	2024	2025	2026	Total
PG&E	$ 265,377	$ 81,507	$ 83,918	$ 86,402	$ 517,204
TURN	$ 358,200	$ 367,871	$ 377,804	$ 388,005	$ 1,491,880
TURN-PG&E	$ 92,823	$ 286,364	$ 293,886	$ 301,603	$ 974,676

[75] WP Table 4-23.

Table 5. PG&E vs. TURN System Hardening Overhead Unit Cost Comparison ($ Thousands)[76]

	2023	2024	2025	2026
PG&E SH OH Unit Cost	$ 1,561	$ 1,630	$ 1,678	$ 1,728
TURN SH OH Cost (CC)	$ 796	$ 817	$ 840	$ 862
TURN-PG&E	$ (765)	$ (813)	$ (839)	$ (866)

Table 6. PG&E vs. TURN System Hardening Overhead Mileage Comparison[77]

	2023	2024	2025	2026	Total
PG&E - SH OH Miles	170	50	50	50	320
TURN - SH OH Miles	450	450	450	450	1,800
TURN-PG&E OH Miles	280	400	400	400	1,480

Covered conductor can be deployed much more quickly and easily than undergrounding.[78] In addition to compliance with existing regulations (see Section II.D above), and potentially other measures that TURN was not able to address due to resource constraints,[79] TURN's recommendations represent an aggressive approach to wildfire mitigation while considering cost-effectiveness and affordability of the overall approach.

C. System Hardening – Underground

1. Summary

Midway through this GRC, PG&E significantly shifted its System Hardening program to focus on undergrounding rather than overhead hardening. PG&E cites to generally higher wildfire risk throughout the West and the notion that "Extraordinary times call for extraordinary solutions."[80] PG&E's longer-term goal is to underground 10,000 circuit miles, 3,300 miles of which it forecasts can be accomplished from 2023-2026. The utility cites the following as justification for its undergrounding initiative:

- Near total elimination of wildfire risk – approximately 99%. "While PG&E has and will continue to use a suite of wildfire mitigation solutions, undergrounding electric lines in

[76] PG&E figures from WP Table 4-23.
[77] PG&E figures from WP Table 4-23.
[78] PG&E Supplemental Testimony, p. 4.3-44, lines 16-18.
[79] As stated above there are 44 programs included in PG&E's GRC to reduce wildfire risk.
[80] PG&E Supplemental Testimony, p. 4.3-7, line 29.

and near HFTDs is the best long-term solution to keep customers and communities safe;"[81]

- Reduction of PSPS and EPSS related outages;[82]
- "Cost benefits to customers" through long-term reductions in operational and maintenance expenses and vegetation management;[83]
- Decreased outages and less need for tree removal.[84]

PG&E forecasts a large increase in the scope of its undergrounding program to over 1,000 miles a year, and forecasts that unit costs will decrease over the period from $3.3 million in 2023 to $2.8 million per underground circuit mile in 2026. The cost of this single initiative is forecast to be around $9.9 billion from 2023-2026.[85]

TURN finds PG&E's undergrounding proposal is significantly less cost-effective than TURN's recommendation to focus on covered conductor, is largely unsupported, and is not consistent with affordable electric rates. Based on our analysis of PG&E's proposal and a comparison with covered conductor deployment, we propose 200 miles of undergrounding over the GRC period to be strategically deployed on the highest risk circuits that also allow PG&E to meet its unit cost forecasts. Assuming the same unit costs as PG&E in each year, this results in the following cost forecast compared with PG&E.

Table 7. PG&E vs. TURN Underground Cost Comparison ($ Thousands)

	2023	2024	2025	2026	Total
PG&E	$ 1,192,578	$ 2,415,857	$ 2,907,624	$ 3,337,360	$ 9,853,419
TURN	$ 166,888	$ 158,209	$ 148,941	$ 139,057	$ 613,094
TURN-PG&E	**$ (1,025,691)**	**$ (2,257,647)**	**$ (2,758,683)**	**$ (3,198,303)**	**$ (9,240,324)**

TURN discusses the following findings in the ensuing sub-sections.

- The scope of PG&E's proposal is inadequately supported.

[81] PG&E Supplemental Testimony, pp. 4.3-9-10.
[82] PG&E Supplemental Testimony, p. 4.3-10, lines 19-27.
[83] PG&E Supplemental Testimony, pp. 4.3-10-11.
[84] PG&E Supplemental Testimony, pp. 4.3-11-12.
[85] WP Table 4-23. Does not include Community Rebuild undergrounding costs.

- PG&E's proposal is even more expensive and less defined than it first appears due to the use of "underground circuit miles" as the primary measure of its undergrounding proposal.
- PG&E provides insufficient evidence that it can achieve up to 1,000 miles of undergrounding, and such scale is not evident in historical data.
- The full scope of PG&E's undergrounding initiative – 10,000 miles – cannot be justified by future cost savings. The net cost to ratepayers of this initiative, if approved, would be severe and burdensome to ratepayers for decades to come, imperiling both affordability and state electrification goals.

2. PG&E's Undergrounding "Plan" is Largely Unsupported

The foundation of PG&E's undergrounding proposal is a **July 2021** announcement that PG&E would pursue 10,000 miles of undergrounding, made about one month after PG&E filed its rate case application, which included absolutely no mention that PG&E might completely overhaul its proposed system hardening program. PG&E subsequently issued a Request for Information (RFI) to engineering and construction firms in **August 2021**.[86] Thus, detailed information on construction practices and costs throughout the industry was sought only <u>after</u> PG&E's Chief Executive Officer (CEO), Patti Poppe, decided to announce PG&E's undergrounding "plan."

Any factual underpinning for the ability of PG&E to deliver on its promises to scale up its undergrounding programs and reduce costs was based primarily on a single "Undergrounding Summit" the utility had on June 25th, 2021, to discuss undergrounding and explore potentially related programs and technologies, including novel technology that transmits electricity through the air with use of electromagnetic energy beams.[87] TURN has reviewed documentation related to PG&E's Request for Information (RFI) and Undergrounding Advisory Group, initiatives undertaken after PG&E announced its program. On the whole, PG&E provides insufficient

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[86] PG&E Supplemental Testimony, p. 4.3-8, lines 8-9; p. 4.3-31, lines 1-3.
[87] Presumably this would obviate the needs for transmission, and potentially some distribution, infrastructure. TURN-154, Question 6, asked for "all documents and analyses relied upon by PG&E in July 2021" related to the 1,000 mile UG goal and $2.5 million unit cost estimate. Dates of attachments as follows: Attachment 1 (June 25, 2021), 2 (July 2021), 4 (July 2021 remarks), 5 (June 25, 2021), 6 (June 25, 2021). This is also confirmed by CEO Patti Poppe's press conference announcement where she stated she had asked her engineers about undergrounding 10,000 miles of lines at a day long event. KCRTV, https://krcrtv.com/news/local/pge-announces-plan-to-bury-10000-miles-of-lines-underground-as-dixie-fire-rages.

support for a project that Ms. Poppe called in her press conference "one of the largest infrastructure projects in the history of our state."[88] If a nuclear power plant was proposed here, would this level of analysis and understanding of the proposed project be acceptable? The Commission accepts at ratepayer peril the level of planning and study that has gone into PG&E's large-scale undergrounding proposal.

While undergrounding overhead miles provides a near-elimination of wildfire risk where deployed, it achieves this result at by far the highest cost of any wildfire mitigation measure. PG&E provides no support in testimony for its program based on Risk Spend Efficiency or a clear analysis that 10,000 miles, or the 3,300 miles forecast here, is the right scope that correctly balances affordability and safety. TURN does not at all oppose undergrounding if used in a strategic fashion to target cost-effective, high-risk lines; on the other hand, PG&E's broad-based proposal to make undergrounding its chief wildfire mitigation effort is fundamentally flawed.

3. PG&E's Program Scope Definition Using "Underground Miles" Translates to Higher Costs on an Overhead Mile Basis

A core issue essential to properly evaluating PG&E's proposal is how the utility defines the number of miles it seeks to underground. Rather than the number of overhead circuit miles that are de-energized - the correct metric from a wildfire risk perspective – the utility defines its forecast and the 10,000-mile metric in terms of "underground circuit miles," which "are generally longer than overhead circuit miles."[89] An underground circuit mile differs from an overhead mile and an underground "trench mile" in that it "measures every mile of primary cable installed underground, which is sometimes installed with multiple cables […] in the same trench."[90] Further, in many instances underground trench miles are longer than overhead circuit miles due to challenges with topography. For example, the overhead line depicted below "crosses creeks, canyons and logging land in a relatively straight line whereas the underground line has to be built as a longer curved path to go around these impediments."[91]

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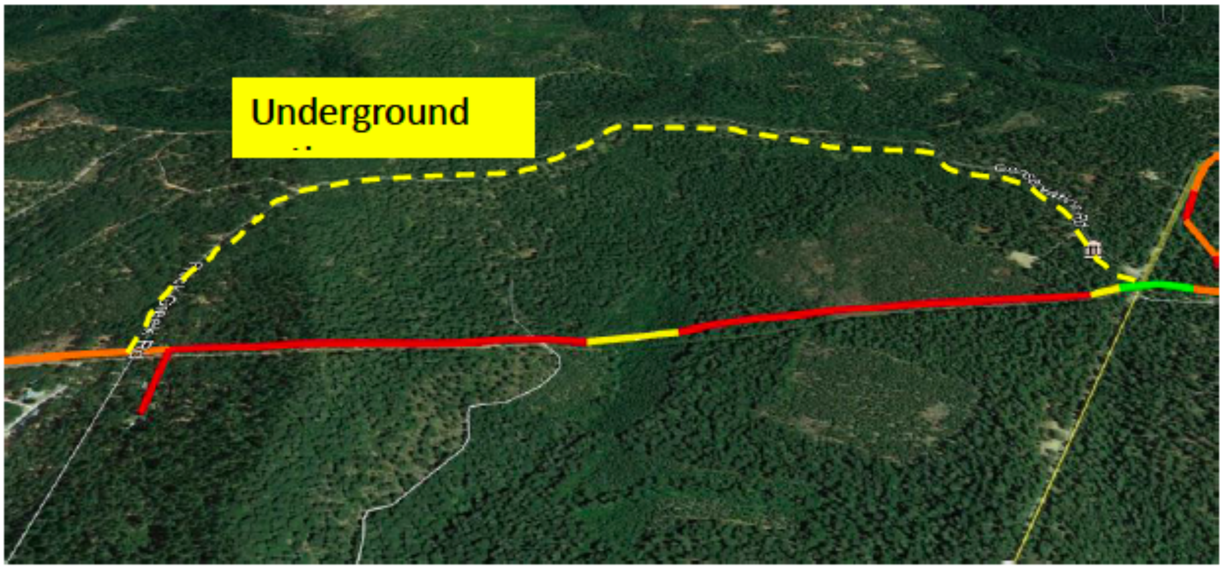
[88] Spoken Comments, KCRTV, https://krcrtv.com/news/local/pge-announces-plan-to-bury-10000-miles-of-lines-underground-as-dixie-fire-rages.
[89] TURN-154, Question 11b.
[90] PG&E Supplemental Testimony, p. 4.3-8, Footnote 7.
[91] TURN-154, Question 11b (also includes the Figure below).

Figure 11. Underground vs. Overhead Circuit Miles



The result of PG&E's selection of underground circuit miles as the measurement of its program is that if PG&E installs 3,297 miles of underground circuits, it will likely de-energize significantly less than that length of overhead circuit miles.

Worryingly for a program of this scale and magnitude, PG&E does not know how many overhead line miles it proposes to underground.[92] An understanding of the number of overhead miles also allows for a comparison of both scope and unit costs to other programs, in particular System Hardening Overhead and TURN's recommendation to focus on deployment of covered conductor. However, PG&E *does* provide an estimate of the number of overhead miles its GRC undergrounding proposal will replace in its risk workpapers, denoted below as "PG&E Assumption." However, the quantitative factor assumed by PG&E to convert underground to overhead miles differs from that used for the Butte Rebuild undergrounding project. The Tables below illustrate the number of overhead miles that may be undergrounded pursuant to PG&E's proposal using these two assumptions to show the potential range, and, importantly, the effect this has on the unit cost (dollars per overhead mile) of PG&E's 3,300 underground mile proposal.

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[92] Related to the 10,000 mile initiative, though I have not seen any precise estimates for PG&E's GRC proposal. TURN-154, Question 11a.

Table 8. Underground Circuit Miles vs. Overhead Circuit Miles[93]

	Miles				
	2023	2024	2025	2026	Total
UG Miles (PG&E Forecast)	357	764	976	1,200	3,297
OH Miles De-energized - PG&E Assumption	286	611	781	960	2,638
OH Miles De-energized - Butte Rebuild	227	485	620	762	2,094

Table 9. Unit Cost for Underground vs. Overhead Circuit Miles ($/Mile)[94]

	Unit Cost			
	2023	2024	2025	2026
Cost per UG Mile (PG&E Forecast)	$ 3,337,750	$ 3,164,187	$ 2,978,818	$ 2,781,133
Cost per OH Mile De-energized (PG&E Assumption)	$ 4,172,188	$ 3,955,234	$ 3,723,523	$ 3,476,416
Cost per OH Mile De-energized (Butte Rebuild)	$ 5,255,181	$ 4,981,911	$ 4,690,054	$ 4,378,805

Even with PG&E's highly touted decreasing unit costs from $3.3 to $2.8 million per UG mile, the Table above demonstrates this equates to **$3.5-$5.3 million per overhead mile** over the GRC period, a cost premium of over **400%** relative to deployment of covered conductor.[95] This does not represent a scalable cost for ratepayers. Undergrounding must thus be seen as a specialized tool for use on targeted miles where it makes the most sense from a risk and cost perspective, not as a broad-based solution as proposed by PG&E.

4. PG&E's Ability to Implement the Huge Scope of its Undergrounding Proposal is Unsupported

[93] From Risk Excel workpaper EO-WLDFR-3_RSE Input File, Tab M002.
[94] From Risk Excel workpaper EO-WLDFR-3_RSE Input File, Tab M002 (miles using different conversion factors); GRC WP Table 4-23 (total costs per year).
[95] Covered conductor costs around $800,000/mile in TY 2023. See Section III.B.1.

PG&E's proposal to underground 3,300 miles from 2023-2026 would require an installation pace that is faster by orders of magnitude higher than any historical undergrounding project or program.

Between 2015 and 2021, PG&E has underground 155 miles,[96] an average of 22 miles per year. On average, based on historical data, we would expect PG&E's proposal to underground 3,300 miles to take around 2,200 years. The quickest pace achieved thus far for a system hardening project would accomplish PG&E's 3,300 mile proposal in 158 years.

Table 10. Time to Underground by Program
Underground Circuit Miles[97]

	Total Miles	Min (Days/Mile)	Max (Days/Mile)	Average (Days/Mile) (1)	Minimum Years to UG 3,300 Miles	Avg Years to UG 3,300 Miles (1)
System Hardening	35	17	1,930	102	158	918
Rule 20A (2015-2021)	82	52	19,933	368	469	3,328
Community Rebuild	39	62	162	105	557	946
All	155	17	19,933	243	158	2,197

(1) Weighted average by miles.

Indeed, the scope for PG&E's original (June 30th 2021 testimony) proposal to underground 45-47 miles per year from 2023-2026 was based on an internal "challenge" to substantially increase the number of system hardening underground miles over the forecast period:

> The 10% goal for undergrounding or line removal [equivalent to around 45 miles per year] was another management goal set to guide the system hardening program to find ways and opportunities to underground circuits. Undergrounding is a more complete mitigation of the wildfire risk over time. **In prior years the system hardening work resulted in 3-5% of the miles being undergrounded and the 10% was put as a challenge to increase that percentage in meaningful manner.**[98]

[96] All miles in this section refer to underground circuit miles.
[97] Calculated from TURN-154, Question 2 Attachment 1. Community Rebuild Project shown in underground circuit miles from TURN-187, Question 3, Attachment 1. System Hardening costs incurred from October 2018-2021, Community Rebuild from November 2020-2021.
[98] TURN-007, Question 3a.

TURN examined documentation related to PG&E's RFI for undergrounding work. Vendors provided large ranges of potential unit costs and "ramping plans" - potentially achievable miles per year - that generally matched what PG&E appeared to request, around 1,000 miles by year 3-4, heavily caveated with numerous risk factors to achieving both unit cost and ramping plan estimates. Some companies believed much more modest scaling of the undergrounding program is achievable - for example up to 200 miles per year rather than 1,000.[99] It is not clear whether these firms understood or studied the exact topography of PG&E's service territory, nor which circuits and areas have the highest wildfire risk. Rather, ramping targets were expected to be achieved by starting with relatively "easy" circuits, such as those with easements, no additional permitting requirements, no culturally sensitive areas, less rocky or otherwise easy to dig soil conditions, or other factors which may or may not actually align with a risk-informed prioritization to undergrounding.[100] Other risks to ramping the program to 1,000 miles per year include material availability, wildfires / natural disasters, resource scarcity (e.g. professional labor), PG&E engineering review process delays, supply chain issues, movement of heavy vehicles, and terrain / soil issues.[101]

Additionally, despite the utility's claims that it "benchmarked with utilities across the country,"[102] PG&E does not know, and has not asked, what other utilities have been able to accomplish in terms of the maximum number of underground miles in a year.[103]

Materials and responses provided with regard to PG&E's Undergrounding Advisory Group also do not support PG&E's contention that it can underground up to 1,000 miles per year.[104] Specifically, no group that participated was even asked whether they agree with PG&E's mileage (or unit cost) targets.[105] PG&E also admits it has made charitable donations to some of the groups involved.[106]

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[99] TURN-154, Question 17, Attachment 1CONF, pp. 49, 62.
[100] See for instance TURN-154, Question 17, Attachment 1CONF, pp. 17, 57.
[101] TURN-154, Question 17, Attachment 1CONF pp. 49, 60,63, 68.
[102] PG&E Supplemental Testimony, p. 4.3-30, lines 28-29.
[103] TURN-154, Question 24a.
[104] TURN-154, Question 25.
[105] TURN-154, Question 25(g), (h).
[106] TURN-154, Question 25(g)(i).

TURN finds that PG&E has not provided sufficient support for its proposed undergrounding mileage targets. There is a substantial likelihood that the mileage targets cannot be accomplished in the timeframe proposed, in addition to the fact that TURN opposes them on cost-effectiveness and affordability grounds. TURN is also extremely concerned that if approved at anywhere near the scope of its proposal, PG&E will choose expediency over risk reduction as it did with its EVM program in 2019 and 2020, where the utility accomplished its work on relatively low-risk lines to meet mileage targets rather than prioritizing the greatest amount of risk reduction by focusing on higher risk areas. This is discussed in Section III.E.

5. PG&E's Forecast of Underground Average Unit Costs are Achievable and Not Particularly Aggressive

PG&E forecasts it can deploy its undergrounding program and decrease costs over time. As shown in the Table above, PG&E forecasts unit cost decreases from $3.3 million to $2.8 million per underground mile from 2023-2026. However, given that PG&E proposes balancing account treatment with any costs up to 25% above forecast deemed reasonable, the real unit cost of PG&E's program may be $3.5 to $4.1 million per underground mile.

PG&E believes it can lower average unit costs by "updating standards" and optimizing materials and equipment used for different types of projects, "strategically packaging work […] to take advantage of economies of scale in construction," "reducing cycle time," and "deploying new and innovative tools, equipment, and technologies to safely increase production rates and tenaciously reduce costs."[107] TURN examined PG&E's historical performance with regard to undergrounding unit cost and information received from vendors as part of the utility's RFI to assess the accuracy of this forecast.

The following Table shows PG&E's historical undergrounding unit costs.

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[107] PG&E Supplemental Testimony, p. 4.3-30, lines 7-22.

Table 11. Unit Cost to Underground by Program
Dollars per Underground Circuit Mile[108]

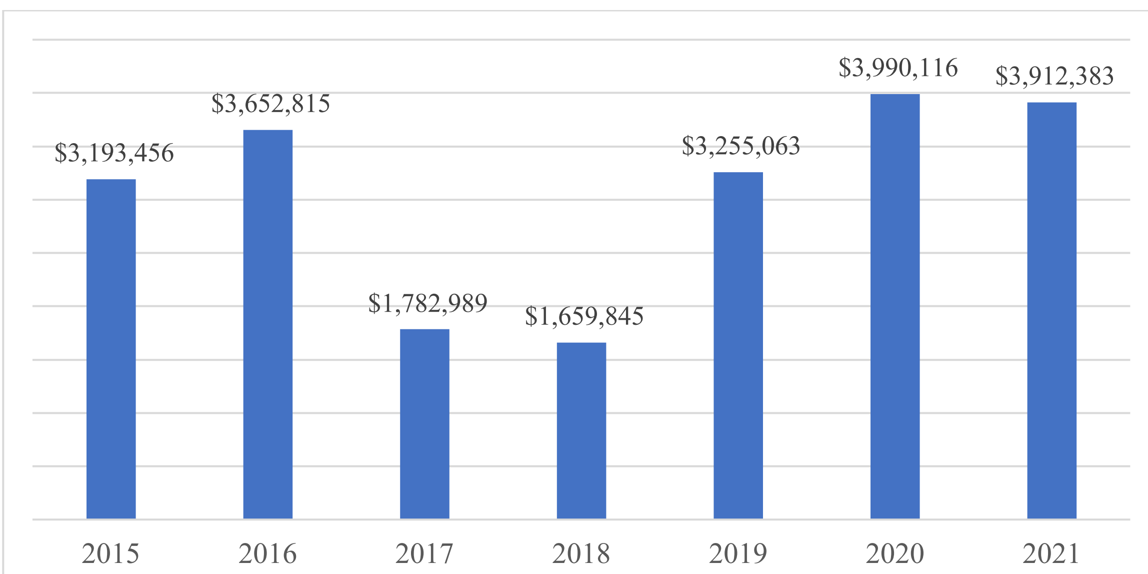
	Total Miles	Min	Max	Average (1)
System Hardening	35	$ 1,174,523	$ 6,358,665	$ 2,535,628
Rule 20A (2015-2021)	82	$ 899,384	$ 7,281,862	$ 2,903,025
Community Rebuild	39	$ 1,259,781	$ 3,064,930	$ 1,994,034
All	155	$ 899,384	$ 7,281,862	$ 2,594,478

(1) Weighted average by miles.

While the Table shows significant variance in unit costs, PG&E has been able to achieve average unit costs across time and projects of around $2.6 million, and just $2 million for the Community Rebuild project.

Average unit costs for the Rule 20A program, the longest-running of the three programs shown above, have varied significantly over the years, generally increasing in recent years over 2017 and 2018.

Figure 12. Rule 20A Average Costs per Mile (2015-2021)[109]



[108] Calculated from TURN-154, Question 2, Attachment 1.
[109] Calculated from TURN-154, Question 2, Attachment 1.

Information received from vendors through the RFI also showed an extremely large variance estimated for minimum, likely, and best-case scenarios,[110] ranging from as low as $250,000/mile to as high as $13 million per mile.[111] As with the range of potential annual mileage targets, costs are highly dependent on a multitude of variables that overlap significantly with the factors listed in the preceding section.[112]

The RFI documentation highlights that undergrounding costs are highly variable depending on terrain and other factors. While there is certainly a multitude of variables and range of costs for various projects, recent PG&E data, particularly from PG&E's Community Rebuild project (incurred from November 2020-2021) indicate PG&E's cost forecast is not particularly aggressive in terms of the level of cost declines sought over the period, and likely starts, in 2023, at a higher average cost than is necessary to underground what are primarily rural HFTD circuits,[113] which generally cost less than urban undergrounding projects.[114] Moreover, PG&E's unit cost forecasts appear much higher when one accounts for 1) a proper comparison to cost per <u>overhead</u> circuit mile, and 2) PG&E's ratemaking proposal. As discussed above, measuring on an overhead mile basis would increase the cost to $3.5-$5.3 million per overhead circuit mile replaced by undergrounding, depending on the year and underground to overhead conversion factor (<u>Table 9</u>~~Table 9~~)including the 25% reasonableness threshold proposed by PG&E this could increase further to $4.4-$6.6 million per overhead mile. PG&E's proposal is thus much more costly to ratepayers than advertised.

6. Despite the Massive Proposed Investment, Most Wildfire Risk Reduction is Expected to Come from PSPS and EPSS

TURN acknowledges that undergrounding has the highest *absolute* risk reduction of any mitigation measure, based on PG&E's risk analysis assumptions, which are addressed in my

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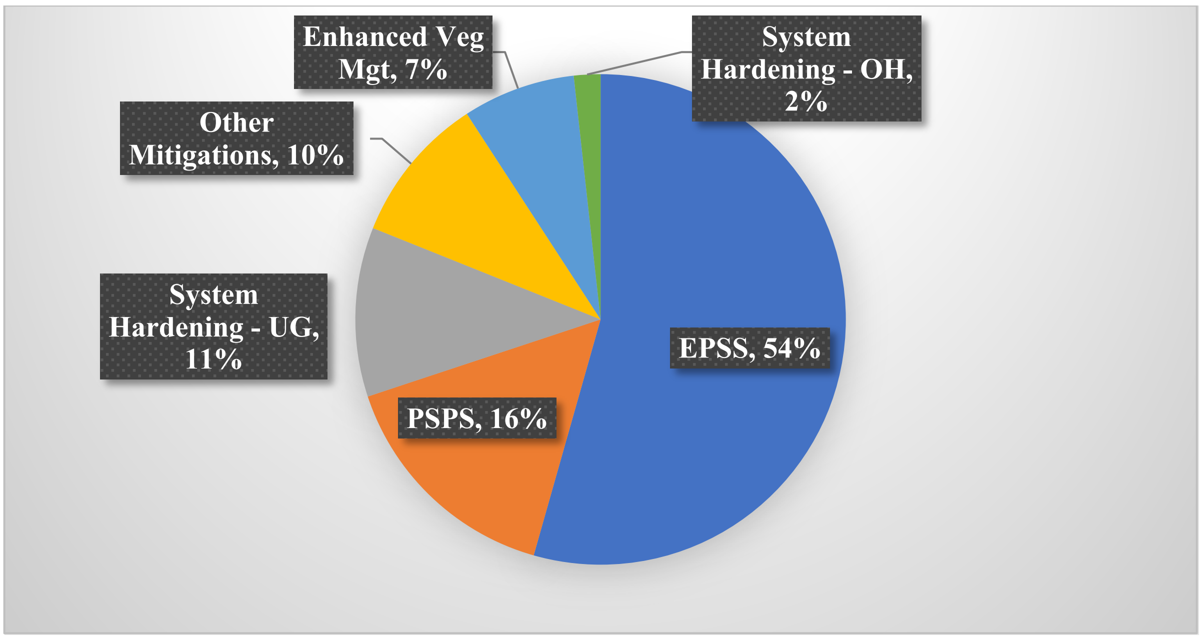
[110] Vendors had differing nomenclature for low and high cost scenarios.
[111] TURN-154, Question 17, Attachment 1CONF, pp. 45, 56.
[112] These include easements, permitting requirements, soil conditions, material availability, wildfires / natural disasters, resource scarcity (e.g. professional labor), supply chain issues, and movement of heavy vehicles.
[113] Just 5% of PG&E's HFTD distribution circuit miles are considered "urban;" the remainder are considered "rural" or "highly rural." PG&E WMP Excel Workpapers, Section 7.3a_Atch01, Table 8.
[114] TURN-154, Question 6, Attachment 5CONF, slide 12.

testimony above, and in more detail in the testimony of Dr. Lesser. However, even with PG&E's unprecedented increase in undergrounding scope over the GRC period, it still expects to rely primarily on EPSS and PSPS to mitigate risk – these mitigations drive 70% of the expected risk reduction.

Figure 13. Percent of Risk Reduction by Mitigation, PG&E Proposal 2023-2026[115]



TURN believes covered conductor deployment is likely to reduce instances of PSPS, as well as significantly decrease the risk of ignition. PG&E states that "Overhead system hardening is expected to reduce the probability of outages and ignitions. The resultant changes to the outage probability are incorporated into the risk models assessing a potential PSPS event."[116]

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[115] Calculated from TURN-154, Question 9, Attachment 1. Average from 2023-2026 for each mitigation. The Figure likely overstates risk reduction of undergrounding because TURN incorporates risk reduction values calculated when EPSS is excluded from "portfolio" results. This Figure only considers "mitigations" and not "controls" for reasons stated in Section II.C. EVM includes both EVM and "Incremental Routine Vegetation Management" which is essentially the tree removal portion of EVM but was moved in PG&E's supplemental filing to the routine program. PSPS risk reduction was approximated to ensure post-mitigation wildfire risk equals PG&E's estimate in Figure 3-1 (PG&E Supplemental Testimony, p. 3-4).

[116] TURN-007, Question 12.

Theoretically, this means lower probability of outages and ignitions provided by covered conductor deployment will also reduce instances of PSPS over time.

As PG&E's own proposal acknowledges, PSPS and EPSS, while not desirable mitigation measures when poorly implemented as in the case of PG&E's 2019 PSPS, are extremely effective mitigations that will significantly drive down the risk of ignition. Programs that achieve regulatory compliance for equipment and vegetation, combined with deployment of covered conductor and undergrounding of the highest risk circuits represent a holistic approach to wildfire mitigation that can significantly reduce the risk of ignition in a cost-effective manner. We view slightly more use of PSPS and EPSS, already the predominant mitigation measure for risk reduction under PG&E's proposal, as a lesser evil compared with adoption of PG&E's enormously costly and insufficiently supported undergrounding proposal.

7. Long-Term Savings From 10,000 Miles of Undergrounding Are Significantly Lower than the Extraordinary Cost

PG&E believes that "undergrounding is an investment that [it] expects will provide long-term savings for customers."[117] These savings are expected to accrue primarily from reduced operation and maintenance (O&M) of overhead facilities compared with undergrounding and vegetation management.[118] Additionally, underground facilities are less prone to outages, including from PSPS events. TURN analyzed these claims by comparing long-term costs of undergrounding to potential savings, finding that annual savings from avoided costs on the overhead system are significantly less than the exorbitant cost of undergrounding.[119] TURN made extremely conservative (i.e. generous to PG&E) cost and savings estimates so that the actual discrepancy between costs and savings may be much greater than indicated by the analysis presented here. For example, we assume that PG&E's average unit cost targets for

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[117] PG&E Supplemental Testimony, p. 4.3-10, lines 30-31.
[118] PG&E Supplemental Testimony, p. 4.3-10.
[119] TURN estimated revenue requirements for these costs using PG&E's Excel model developed for the purpose of estimating the cost and rate impacts of various scenarios. Model provided in TURN-154, Question 6, Attachment 3. In addition to extending the model to reflect a 50 year depreciation life for UG to reflect the currently adopted depreciation life (TURN-201, Question 4), the model assumed 95% of costs would be moved to ratebase – we adjust this to 100%. We also increase the equity percentage to 52.5%, and decrease the debt percentage to 4.12%, from 52% and 4.17%, respectively, to correct an error and match currently authorized WACC of 7.338%. See TURN-201, Questions 1-6.

undergrounding are met over the GRC period, with a further decline to $2 million per mile for each year from 2027-2031, which PG&E calls "aspirational."[120] On balance, the results indicated here may be properly viewed as akin to a "best case" scenario.

TURN compared annual revenue requirements for undergrounding to potential savings if 10,000 miles are undergrounded from 2021-2031, assuming that savings due to avoided vegetation management and other operational costs occur over the full 50-year useful life of undergrounding infrastructure. We find that on a net present value basis operational savings provide just an 18% reduction to costs of undergrounding, while the economic value of avoided PSPS outage costs provide an additional 18%, more than 75% of which accrues to commercial customers.[121] Savings due to undergrounding thus come nowhere close to accomplishing financial neutrality for ratepayers, as shown below.

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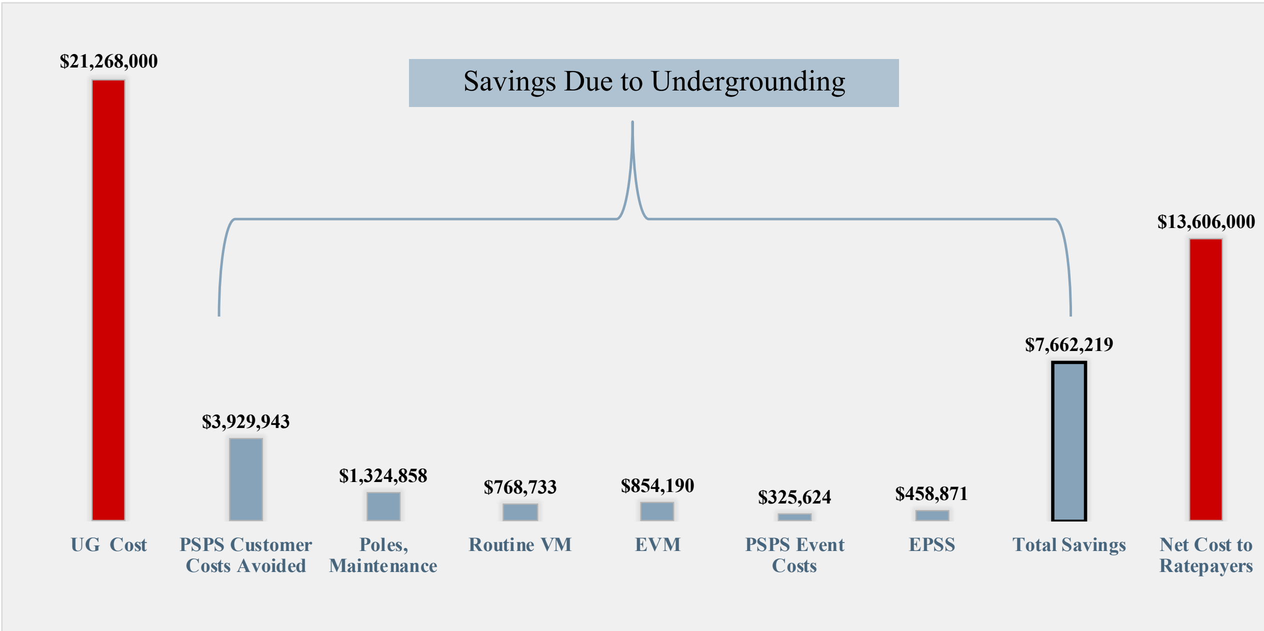
[120] TURN-154, Question 6, Attch5CONF, slide 13.

[121] As opposed to residential customers. TURN-154, Question 6, Attch5CONF, slide 14. PG&E estimates $28,000 per mile for these costs. Value of lost load assumed to be $5/kWh for residential customers and $130/kWh for commercial customers; PG&E calculates that around $22,000 of the $28,000 per mile is for commercial customers (79%).

Figure 14. 10,000 Miles of Undergrounding - Costs vs. Savings
($ Thousands, Present Value)[122]



Even with all operational and customer savings included, undergrounding 10,000 miles would still result in a net cost of over $13 billion on a present value basis. This number far exceeds the cost that ratepayers would incur if PG&E installed covered conductor on 10,000 miles, $6.7 billion on a present value basis.[123] In other words, covered conductor is still significantly more affordable than undergrounding even when one considers long-term savings from undergrounding.

PG&E implied in discovery that it realized large cost savings due to undergrounding over the rate case cycle by "lower[ing] its forecast expenses for Vegetation Management by

[122] Revenue requirements for costs are estimated using PG&E's Excel model developed for the purpose of estimating the cost and rate impacts of various scenarios. Model provided in TURN-154, Question 6, Attachment 3. TURN presents a more detailed description of the inputs included in this analysis in Appendix 1, which relies almost exclusively on PG&E's own data and assumptions as the basis of costs and savings estimates.

[123] Calculated using the same workbook as underground costs from TURN-154, Question 6, Attachment 3. Assume TURN unit costs for covered conductor discussed in Section III.B.1, plus escalation, and the underground to overhead conversion factor from PG&E's risk workpapers (~1.25). See Risk Excel workpaper EO-WLDFR-3_RSE Input File, tab M002.

approximately $1 billion" between the original GRC filing and supplemental filing.[124] Appendix 2 explains why this claim is misleading because the reduction is primarily due to PG&E's assumption of a reduced unit cost for some vegetation management work, not due to the implementation of undergrounding.

8. Summary of TURN's Findings and Recommendations Regarding Undergrounding

TURN finds above that there is little basis to believe that PG&E can achieve the scope of its undergrounding proposal; and even if it could, it is far too expensive to be consistent with a cost-effective and affordable approach to wildfire mitigation. Rather than utilizing it as the primary way to address wildfire risk, undergrounding is a highly specialized mitigation measure that must be used strategically where it makes the most sense from a cost and risk reduction perspective.

TURN recommends that PG&E slightly exceed its previous "challenge" goal and underground 50 miles per year over the forecast period, a more than doubling of its average previous pace for all undergrounding programs (see Section III.C.4 above). Over the next ten years, this would allow PG&E to address the top 20% of wildfire risk with undergrounding, according to PG&E's current risk model. This reflects both a scaling up of the program as well as a more strategic approach to undergrounding than PG&E's proposal.

D. Summary of TURN's System Hardening (Overhead and Underground) Recommendation

TURN's analyses demonstrate that the deployment of covered conductor combined with more strategic use of undergrounding to the highest risk miles is a more cost-effective and affordable approach to undergrounding. PG&E has not only provided inadequate support for its proposal to underground 3,300 miles from 2023-2026, it has also inadequately considered cost-effectiveness and affordability. TURN views undergrounding as a critical wildfire mitigation strategy – but a targeted and specialized one compared with PG&E's broad-based approach. Any mitigation strategy beyond meeting compliance standards and strategic use of PSPS and EPSS should be

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[124] TURN-154, Question 20.

based on covered conductor deployment, which is generally quicker and significantly less expensive.

TURN recommends greater deployment of the overhead program coupled with less deployment of undergrounding, resulting in a proposal to accomplish 1,800 miles of covered conductor and 200 miles of undergrounding over the GRC period. This proposal results in the following cost differences.

Table 12. PG&E vs. TURN System Hardening Costs ($ Thousands)[125]

	System Hardening - Overhead				
	2023	2024	2025	2026	Total
PG&E	$ 265,377	$ 81,507	$ 83,918	$ 86,402	$ 517,204
TURN	$ 358,200	$ 367,871	$ 377,804	$ 388,005	$ 1,491,880
TURN-PG&E	$ 92,823	$ 286,364	$ 293,886	$ 301,603	$ 974,676
	System Hardening - Underground				
PG&E	$ 1,192,578	$ 2,415,857	$ 2,907,624	$ 3,337,360	$ 9,853,419
TURN	$ 166,888	$ 158,209	$ 148,941	$ 139,057	$ 613,094
TURN-PG&E	$ (1,025,691)	$ (2,257,647)	$ (2,758,683)	$ (3,198,303)	$ (9,240,324)
	System Hardening - Total				
PG&E	$ 1,457,955	$ 2,497,364	$ 2,991,542	$ 3,423,761	$ 10,370,622
TURN	$ 525,088	$ 526,081	$ 526,745	$ 527,061	$ 2,104,974
TURN-PG&E	**$ (932,867)**	**$ (1,971,283)**	**$ (2,464,798)**	**$ (2,896,700)**	**$ (8,265,648)**

E. Wildfire Mitigation Accountability and Cost Control Measures

Analysis of PG&E's past deployment of wildfire mitigations demonstrate that effective and prioritized implementation matters as much as a reasonable forecast of activities. For example, if PG&E had simply complied with its legal obligations, the Camp Fire would not have occurred.[126] In order to protect ratepayer investments and improve future results, TURN proposes additional accountability measures that seek to provide a framework for spending in addition to the dollars allocated from ratepayers.

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[125] PG&E Figures from WP Table 4-23, undergrounding figures do not include Community Rebuild program.
[126] D.20-05-019, p. 11. In addition, as previously noted, PG&E pleaded guilty to 84 counts of involuntary manslaughter in causing the Camp Fire.

1. The Commission Must Ensure System Hardening Work is Targeted to the Highest Risk Miles

As the concentration of risk found by PG&E's modeling makes clear, not all work accomplished to mitigate wildfire risk in PG&E's HFTD is created equal. This is well-known by the Commission – PG&E's inability to focus its EVM program on the highest risk miles caused it to be placed into Step 1 of the Enhanced Oversight and Enforcement Process, which required a Corrective Action Plan including ongoing data collection and reporting to ensure the utility is prioritizing the highest risk lines.[127] This principle of doing the highest risk work – not just ticking off mileage goals - is critical for overhead and underground system hardening, as these represent the most expensive mitigation measures available to the utility. PG&E has previously stated it will target 80% of system hardening work to the highest risk circuits, rather than 100% to allow for other factors to drive deployment, though it admits **"there is no barrier […] preventing PG&E from doing 100% system hardening work from highest to lowest [risk] based on the risk model."**[128]

PG&E identified additional factors other than risk prioritization it may use for its undergrounding proposal:

- Locations where undergrounding will eliminate the need to use PSPS as a measure of wildfire protection;
- Spreading the work across geographic zones (county level, but may also be more granular) so that a single zone is not overwhelmed by the construction work and traffic control required to perform undergrounding in any one year; and
- Factoring in the site-specific aspects (e.g., subsurface layer (granite for example), waterways, and slope of terrain) and environmental factors that may mean undergrounding is not the right mitigation.[129]

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[127] See, for example, PG&E Corrective Action Plan 90 Day Report, 5/3/22. Table 1 shows that most of the work is now being accomplished on the highest-risk lines and item 4 provides "a description of how the list in item 3 above ensures PG&E is prioritizing the power lines with highest risk first."
[128] TURN-004, Question 3b.
[129] TURN-154, Question 7e(i).

It is not clear the extent to which these factors would require deviations from a purely risk-informed approach; however, they are vague enough that they may. While TURN does not oppose some flexibility in implementing the system hardening program to achieve unit cost or deployment efficiencies, we are concerned that PG&E will target completing "number of miles" rather than completing the "right miles" from a wildfire risk perspective. This is an even greater concern if a large-scale undergrounding program is approved, whereby PG&E will be incentivized to achieve a mileage target rather than ensure the greatest amount of risk reduction.

At minimum, the Commission must implement an accountability measure that directs PG&E to perform all system hardening work (overhead and underground) in the top 50% of risk (comprising around 3,600 overhead miles of PG&E's HFTD),[130] ideally with the majority of undergrounding work concentrated almost completely in the very top percentiles of risk where cost effective.[131] Depending on the specific proposal authorized by the Commission, TURN would support even more stringent focus on the highest risk circuits.[132] This accountability metric should be tracked and audited by Energy Division on an annual basis; if system hardening work occurs outside of these highest risk areas, costs for that work should be refunded to ratepayers.

2. Maximum Unit Costs of Undergrounding Should be Adopted to Ensure PG&E is Held to a Reasonable Forecast

PG&E claims its forecast costs will decline from $3.3 million to $2.8 million per underground mile over the forecast period. As TURN indicates above, we do not find this a particularly aggressive forecast based on recorded data. Therefore, it is reasonable for the Commission to set a cap of $2.98 million per UG mile on a weighted average basis[133] over the GRC period, which is PG&E's forecast.[134] Any costs reflecting a unit cost above $2.98 million on a weighted average

[130] See Figure 1~~Figure 1~~.
[131] Highest risk miles should be based on the most current risk model at the time an undergrounding project is planned and executed.
[132] For example, TURN's undergrounding proposal for 200 miles over the forecast period could be focused on a much narrower subset of highest risk circuits such as the top 20%-30% of risk.
[133] This can be calculated as the sum of total dollars spent divided by total miles.
[134] Calculated from WP Table 4-23.

basis should be disallowed as unreasonable and not recovered from ratepayers. PG&E should demonstrate to the Commission in its next GRC the unit costs it recorded in its undergrounding program, and that it has complied with this unit cost cap.

3. Any Large-scale Undergrounding Program Approved by the Commission Should Leverage Outside Funds and be Financed at the Cost of Debt

TURN strongly opposes PG&E's costly and inadequately supported large-scale undergrounding program. If anything above TURN's 50 mile per year proposal is adopted, TURN believes that outside funding should be leveraged first, for example from the state or federal government where PG&E spends a considerable amount of time and money lobbying.[135] To the extent ratepayers bear costs of the undergrounding program, any large-scale proposal should be financed entirely by debt, without a return on equity component. While still likely unaffordable for ratepayers, this represents a less costly alternative.

With this alternative financing structure, ratepayers would save approximately $18 billion in return on equity and income taxes over the 50 year depreciation life of PG&E's GRC proposal.[136] Additionally, this structure would help reduce any disincentive PG&E perceives in offsetting its undergrounding costs with external funding, which is a concern given PG&E's CEO's statements that the utility would only be interested in offsetting O&M expenses, rather than capital expenditures.[137] This PG&E preference is not surprising, and is consistent with a strategy that seeks to maximize shareholder returns through large-scale capital projects like undergrounding 10,000 miles of power lines.

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[135] PG&E, https://www.pgecorp.com/corp/about-us/corporate-governance/corporation-policies/political-engagement/advocacy-lobbying.page.

[136] The total upfront cost of PG&E's proposal is around $10 billion (see above). Nominal dollars. $13.8 billion for return on equity and $6 billion in taxes. Calculated from PG&E's Excel model developed for the purpose of estimating the cost and rate impacts of various scenarios, including undergrounding. Model provided in TURN-154, Question 6, Attachment 3.

[137] Patti Poppe comments during 4/28/22 Earnings call with investors (transcript from *Seeking Alpha*): "Now that's not to say that we would object if somebody wanted to help contribute things related to other parts of the wildfire expenses, for example, if there was external funding for vegetation management or some of the expense-related issues associated with our wildfire plans, I think that would be something that we were very interested in talking to people about. But we think the undergrounding investment is the right investment for customers and we can offset the cost through the expense reductions."

IV. Enhanced Powerline Safety Settings

PG&E's Enhanced Powerline Safety Settings (EPSS) program was added as part of PG&E's Supplemental Testimony, with forecast costs of $151 million in TY 2023.[138] The purpose of the program is to adjust system protective devices to make them "more sensitive and able to react to a fault more quickly."[139] The primary cost for EPSS are for patrols after an outage due to these settings occurs, and for customer outreach and incentives, which includes a "Fixed Power Solutions" pilot program to provide financial incentives to vulnerable customers for back-up power technologies.[140] These two cost areas comprise 97% of costs, with the remainder due to incremental control center, device programming, and substation support.[141] Though the proposal lacks implementation details, TURN supports the Fixed Power Solution pilot, though we note it should be targeted as much as possible to Medical Baseline and Medical Baseline-eligible customers as these residents face the most dire impacts of power outages.

1. PG&E's Forecast Patrol Costs for Enhanced Powerline Safety Settings is Flawed

PG&E's forecast unit cost (dollars per overhead circuit mile) for EPSS circuits is a 117% increase over 2021 costs, $3,435 versus $1,583, respectively.[142] Additionally, the absolute increase for this cost area is 789% for TY 2023 compared with 2021 recorded costs - $113 million versus $13 million.[143]

The primary reason for this discrepancy is the methodology relied upon by PG&E to forecast additional patrol costs that occur after there is an outage on an EPSS-enabled circuit, since PG&E has to inspect the entire applicable circuit mileage prior to re-energizing the line. Instead of recognizing that these costs vary based on the number of line miles subject to EPSS-related

[138] PG&E Supplemental Testimony, p. 4.6-5, Figure 4.6-2.
[139] PG&E Supplemental Testimony, p. 4.6-6, line 9.
[140] PG&E Supplemental Testimony, p. 4.6-18, lines 1-4.
[141] Workpaper Table 4-32, MWC BH records costs due to "additional patrols" and MWC IG for Customer Support Activities.
[142] TURN-155, Question 1, Attachment 1; TURN-155, Question 3, Attachment 2. PG&E Supplemental Testimony, p. 4.6-6, lines 16-17, state "In 2021, PG&E enabled approximately 11,500 HFTD circuit miles across 170 circuits to operate in EPSS mode."
[143] WP Table 4-32, MWC BH.

outages, PG&E applies 2021 recorded average costs per circuit to the number of forecast circuits every month, reduced by 20% for "efficiency", to derive a forecast cost for 2022 and 2023.[144] This methodology does not recognize the fact that circuits have a highly variable number of miles, and thus very different costs for patrols after an outage, depending on which circuits or portions of circuits experience an outage.

Instead, TURN recommends utilizing recorded 2021 recorded unit costs per circuit mile, rather than circuit. This reflects the fact that recorded unit costs on a cost per circuit basis are unlikely to lead to an accurate forecast because circuits vary tremendously in length. TURN provides the impact of the change in unit cost methodology below, as well as the total cost impact which recognizes that we do not oppose the other cost elements of PG&E's forecast for EPSS. We also do not oppose the number of EPSS-enabled circuit miles (44,000), which assumes "multiple outages could occur on each circuit with associated patrol costs funded through the EPSS program,"[145] though this estimate was unsupported and may be higher than necessary considering the 2021 recorded statistic was 11,500 circuit miles in PG&E's HFTD.[146]

[144] WP Table 4-38.
[145] TURN-155, Question 3d.
[146] PG&E Supplemental Testimony, p.4.6-6, lines 16-17.

Table 13. PG&E vs. TURN Unit and Total Cost Estimate of EPSS Patrol Costs

	Circuit Miles (1)	Cost per Circuit Mile (2)	Total
PG&E	44,000	$ 2.56	$ 112,510
TURN	44,000	$ 1.10	$ 48,430
TURN-PG&E	-	$ (1.46)	$ (64,080)

(1) TURN-155, Question 3, Attachment 2.
(2) PG&E: Total Cost (WP Table 4-32, based on WP Table 4-38) / Number of Circuit Miles. Total cost based on forecast circuits per month in 2022 * Avg Cost per Circuit * Efficiency Factor (see WP Table 4-38). TURN: 2021 recorded unit costs, TURN-155, Question 1, Attachment 1.

Table 14. TY 2023 EPSS Forecast Cost
PG&E vs. TURN

MWC	PG&E	TURN	TURN-PG&E
BA	$ 2,219	$ 2,219	$ -
FZ	$ 2,063	$ 2,063	$ -
GC	$ 833	$ 833	$ -
BH	$ 112,510	$ 48,430	$ (64,080)
IG	$ 33,504	$ 33,504	$ -
Total	**$ 151,129**	**$ 87,049**	**$ (64,080)**

As seen above, TURN recommends a $64 million reduction to PG&E's forecast EPSS costs. The $87 million total costs supported by TURN for TY 2023 EPSS represents a 378% increase over recorded 2021 EPSS costs.[147]

V. Public Safety Power Shutoffs

PG&E forecasts four PSPS events per year starting in 2021 in its GRC filing, though the utility states its Wildfire Mitigation Plan (WMP) modifies this to an expected five PSPS events per year.[148] PG&E forecasts $73 million for PSPS events in 2023, based on the average cost per PSPS event in 2019 and 2020 multiplied by the expected four PSPS events.[149]

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[147] TURN-155, Question 1, Attachment 1.
[148] PG&E Supplemental Testimony, p. 4.2-3, lines 3-5.
[149] PG&E Supplemental Testimony, p. 4.2-20, lines 29-31. $79.8 million for 10/26-11/1 event of $178.8 million total for the year.

PG&E's forecasting methodology for PSPS event costs is flawed. By taking a simple average of event costs in 2019 and 2020, PG&E ignores the fact that each "event" is substantially different, some with hundreds of thousands of customers over vast swathes of PG&E's HFTD, and others which are much smaller involving thousands or even hundreds of customers, the latter costing significantly less than the former. For example, one "event", in November 2019, consisted of almost 1 million customers and represents 44% of the PSPS event costs, though there were 7 PSPS events in 2019.[150]

PG&E's cost forecast methodology for PSPS also ignores the fact that its stated goal is to *reduce* the size and impact of PSPS events, which will lower costs (shown below). PG&E states it has succeeded in this in 2020, when it "reduced the number of customers impacted by each PSPS event by approximately 55 percent on average in 2020, when compared to the number of customers that would have been impacted by the same weather conditions under our 2019 PSPS program."[151] The utility expects this progress to continue:

> PG&E's focus is on continuing to improve our PSPS program to reduce the impact of PSPS on our customers by working to make **future PSPS events smaller in scope,** shorter in duration, and smarter in performance while safeguarding customers and communities from wildfire risk during times of severe weather.[152]

PG&E's efforts have been successful in recent years in reducing the size of its PSPS events, also indicating the lack of experience or other factors affecting 2019 PSPS.

Figure 15. Average Customers Impacted per PSPS Event[153]

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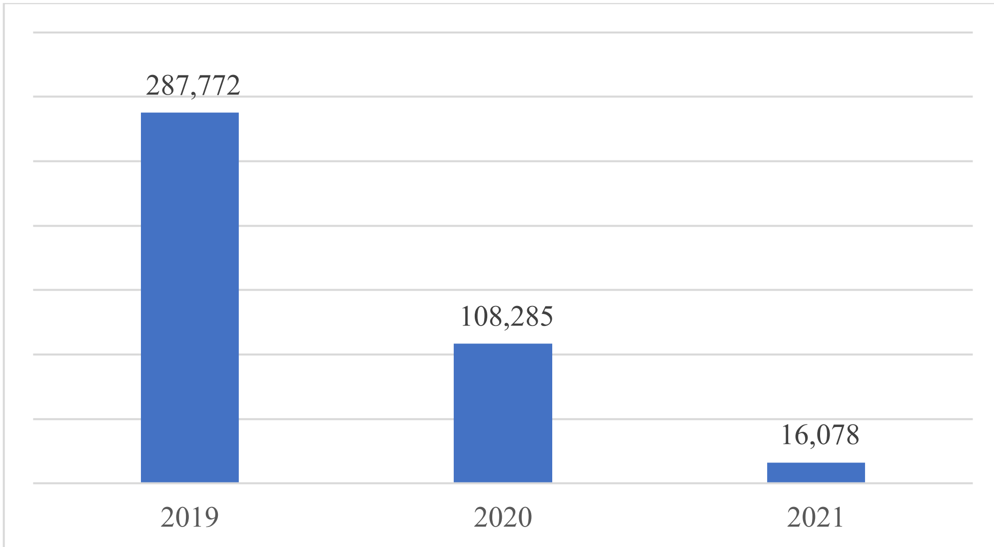
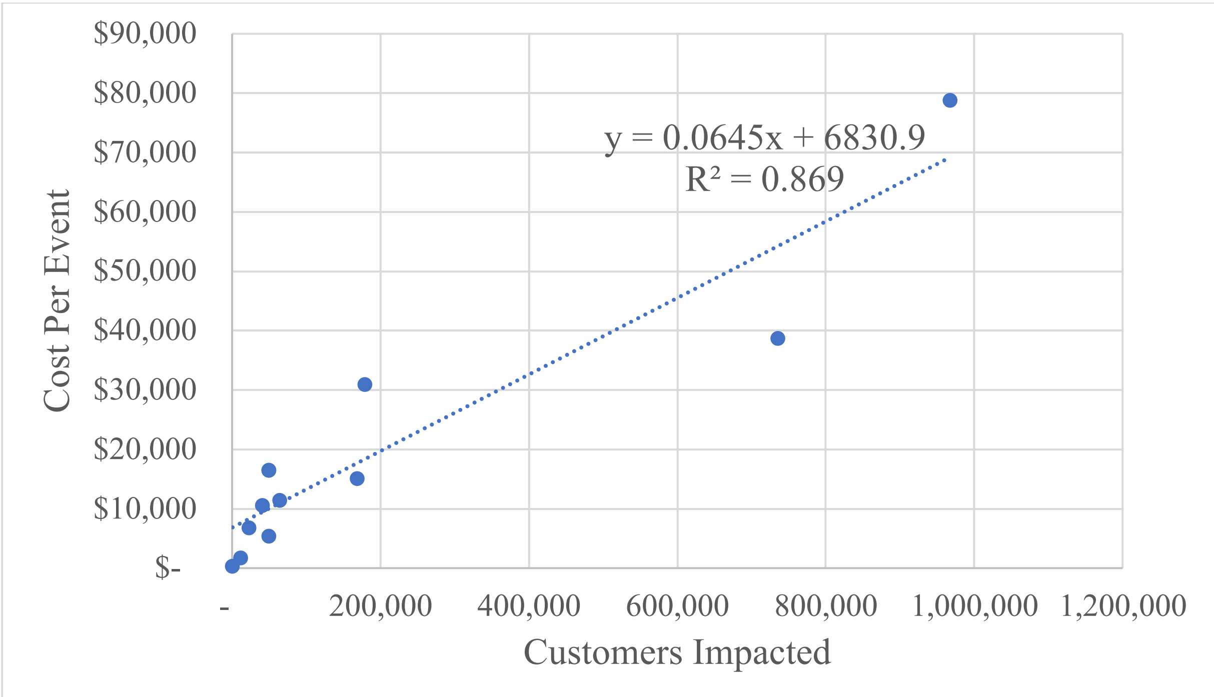
[150] Excel Risk workpaper EO-WPSPS-5_PSPS Financial Event Cost
[151] PG&E Supplemental Testimony, p. 4.2-9, lines 16-20.
[152] PG&E Testimony, p. 4-8, lines 25-29.
[153] Excel Risk Workpaper WO-WPSPS-5_PSPS Event Financial Cost (2019 and 2020). 2021 summarized from PG&E PSPS Reports, https://www.pge.com/en_US/residential/outages/public-safety-power-shuttoff/psps-reports.page.



1. The Size and Cost of PSPS Events are Highly Correlated

Examination of historical data indicates that PSPS event costs are highly correlated with the number of customers de-energized. The trendline below shows a fitted curve with an R^2 value of 87%, meaning that 87% of the variability in the cost data can be explained by a trendline that examines the correlation of event costs with the number of customers impacted.

Figure 16. Customers Impacted and Cost of Event for PSPS Events (2019-2020)



PG&E's methodology – assuming that average 2019-2020 PSPS costs are representative of costs that will be incurred in TY 2023 – ignores the fact that it seeks to substantially reduce the size and footprint of its events over time. As shown above, this will reduce the cost of these events.

A more accurate methodology to forecast PSPS costs would estimate costs using a reasonable forecast of the number of customers expected to be impacted by each PSPS event in TY 2023, incorporating expected improvements in the utility's performance. TURN outlines how this should be accomplished in the section below.

2. Improvements in PSPS Performance Should be Incorporated into PG&E's Cost Forecast

As demonstrated above, a simple average of all PSPS event costs in 2019 and 2020 multiplied by the number of events in 2023 is unlikely to produce an accurate forecast for PSPS events conducted in 2023. Instead, TURN recommends the average number of customers per event in 2021 be the starting point to forecast TY 2023 costs, considering PG&E's commitments to improve its targeting of PSPS events each year and the fact that 2021 represents an average weather year with regard to wildfire risk.[154] TURN also incorporates expected improvements in PSPS scope due to deployment of sectionalization devices in 2022 and 2023, to ensure the benefits of these measures are passed along to consumers in the form of forecast cost reductions. Finally, we incorporate the expected size (number of customers) of each PSPS event into the regression equation provided in Figure 16~~Figure 16~~ above to forecast TY 2023 costs.

Table 15. TURN Forecast TY 2023 PSPS Costs

Average Customers per PSPS Event, 2021 (1)	16,078
Improvement (Decrease) due to Sectionalizing 2022-2023 (2)	5%
Forecast Customers per Event, TY 2023	**15,259**

Cost per Event (3)	$ 7,815
PSPS Events TY 2023 (4)	5
Total Cost PSPS Events	$ 39,075
Escalation (5)	6.28%
TURN PSPS Event Cost Forecast, TY 2023	**$ 41,529**

Notes:

(1) Average customers per PSPS event in 2021, from https://www.pge.com/en_US/residential/outages/public-safety-power-shuttoff/psps-reports.page.

(2) Risk Excel Workpapers EO-WSPS-3_RSE Input File, tab "Sect-Exposure"

(3) Per regression equation of 2019-2020 PSPS Customers Impacted vs. Cost, assuming forecast customers per event shown here.

(4) Increased from 4 events forecast in PG&E GRC to 5 events per PG&E WMP.

(5) Cumulative escalation, TURN-11, Question 3, Attachment 1.

The $42 million recommendation pursuant to this methodology represents a $31 million reduction to PG&E's forecast costs in TY 2023 relative to PG&E's forecast.

[154] PG&E 2021 WMP filing, Excel Table 6. Red Flag Warning (RFW) Circuit Mile Days is the chosen metric in the WMP indicating risky fire weather, measuring the length of time and number of overhead circuit miles that experience a RFW throughout the year. 2021 RFW circuit mile days was 440,246; the average from 2015-2021 was 474,273.

Appendix 1. Model Assumptions for Ratepayer Savings Due to Undergrounding

First, we apply PG&E's estimate of around $9,400 per mile for maintenance cost savings of the underground system compared with overhead, based on PG&E's risk workpaper assumptions which analyze average historical actual costs.[155]

Routine VM savings are based on PG&E assumptions regarding fewer trees worked due to UG assumed in the GRC workpapers from 2021-2026.[156] To forecast these savings past 2026, we calculate trees per mile, assumed from 2021-2026, and apply these to the cumulative number of miles undergrounded in each year, 10,000 after 2031.

EVM cost savings assume all costs forecast for the program (escalated for inflation using PG&E's forecast) are avoided approximately every 8 years for 8 years, since the program is forecast to work 1,800 miles per year (accomplishing slightly more than 10,000 miles over 8 years) while the remainder of PG&E's 25,500 mile HFTD will still incur costs for the EVM program even when 10,000 miles are underground.[157]

EPSS savings are estimated based on PG&E's dollar-per-circuit-mile cost forecast for TY 2023.[158] These are escalated after 2023, which is conservative since PG&E expects declining costs after this year in part due to "further optimization of EPSS settings and learnings from patrols in 2022 and 2023."[159]

Finally, the economic value of foregone PSPS outages is estimated based on the value of service to residential and commercial customers. This is included as a savings in TURN's estimates and based on PG&E assumptions and calculations to convert these values to an expected dollar per mile statistic.[160] Separately, avoided PSPS event costs to conduct PSPS are also based on PG&E's estimates of the cost on a per mile basis.[161]

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[155] EO-WLDFR-3, tab M002.
[156] WP Table 9-10, lines 21, 25.
[157] From WP Table 9-11.
[158] TURN finds above that PG&E's estimate of these costs are unnecessarily high (see Section IV) so this is a conservative (high) estimate. Total costs from WP Table 4-32, divided by circuit miles expected to be EPSS enabled from TURN-155, Question 3, Attachment 2.
[159] WP Table 4-36, note 3.
[160] TURN-154, Question 6, Attch5CONF, slide 14. PG&E's calculations find these savings would be about $28,000 per mile, the majority of which accrues to commercial customers. Value of lost load assumed to be $5/kWh for residential customers and $130/kWh for commercial customers.
[161] TURN-154, Question 6, Attch5CONF, slide 13. $2,320 per mile, escalated and applied to the number of cumulative underground miles. All savings are escalated over the 50 year period based on PG&E's assumption of 2.5% inflation, which we leave constant over the entire period (TURN-154, Question 6, Attachment 3, summary tab).

Appendix 2. Vegetation Management Savings Incorporated into PG&E's Supplemental Filing Are Not Due to Undergrounding

In discovery, PG&E implied that due to the large-scale undergrounding proposal in the supplemental filing it "lowered its forecast expenses for Vegetation Management by approximately $1 billion."[162] However, when comparing the June 30, 2021 and Supplemental February 25, 2022 filings, the approximately $1 billion reduction in vegetation management (VM) costs are not due to PG&E's undergrounding program.[163] While PG&E appears to incorporate a very small amount of "savings" due to undergrounding into its VM forecast, equivalent to $43 million from 2023-2026,[164] the primary reason for decreased vegetation management costs ($954 million in total) in PG&E's supplemental filing is due to a reduction in unit costs for EVM tree removal. PG&E significantly reduced its original June 30th forecast of $5,000-$6,000 per tree for its EVM program, to around $500-$600, consistent with historical figures, for what PG&E termed "incremental hazard tree removal," included in the utility's routine VM program.[165] Additional VM savings between the filings come from decreases in forecast costs for defensible space, wood management, and safety oversight and work verification as part of the supplemental EVM program, as well as other adjustments.

Analysis of the two filings show that PG&E engaged in a shell game, decreasing vegetation management costs while actually *increasing* the number of proposed tree trims and removals over the period by 60,000 trees on net across the routine VM and EVM programs. The Figure below *includes* supposed reductions to VM and incremental hazard tree removal scope due to UG work.

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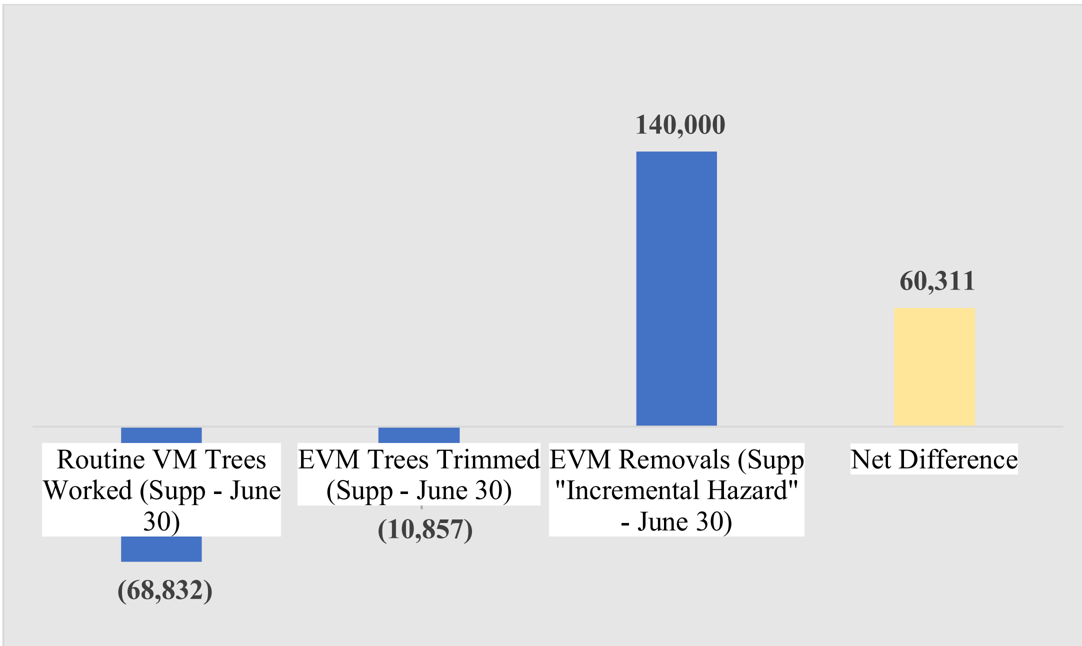
[162] TURN-154, Question 20.
[163] TURN-154, Question 20.
[164] WP Table 9-11 (Supplemental Testimony), "Reduce Trees Work Due to UG" multiplied by average unit cost for each year 2023-2026.
[165] TURN-177, Question 3a: "Hazard tree removals are included in the Enhanced VM scope of work through 2022 and then transition to Routine VM in 2023 in the Incremental Routine VM scope of work."

Figure 17. Trees Trimmed/Removed – Supplemental 2/25 Filing vs. Original June 30, 2021 2023-2026[166]



While TURN appreciates that PG&E appears to incorporate efficiencies and a more reasonable unit cost estimate for its EVM tree removal efforts, any claim that VM cost reductions are due to inclusion of PG&E's large-scale undergrounding program is not true. Moreover, due to two-way balancing account treatment for vegetation management expenses, if PG&E's lower unit cost forecasts turn out to be overly optimistic, PG&E may still seek recovery of any overspending in a future application.[167]

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[166] Calculated comparing WP Tables 9-10 and 9-11 of the two filings (Supplemental 2/25/22 and original 6/30/21). PG&E will conduct the same number of tree trims per mile in the EVM program but reduced the number of miles in the Supplemental filing from 1,890 to 1,800 per year. June Tree removals included as part of PG&E's EVM program were moved to the routine VM program and called "incremental hazard trees" starting in 2023. Thus, "EVM Removals" in this Figure compares the 6/30/21 filing EVM removals for 2023-2026 to "Incremental Hazard Tree" removals included from 2023 in the routine VM program as part of the 2/25/22 filing. PG&E Supplemental Testimony, p. 9-41, lines 1-4: "As PG&E transitions to the One Veg model it will develop and conduct training, implement new processes and procedures, develop new tools and, by 2023, move radial clearance and hazard tree identification and removal from Enhanced VM to Routine VM."

[167] See Testimony of TURN Witness Robert Finkelstein (TURN-13).

Appendix 3. TURN's Estimate of Overhead System Hardening Effectiveness Sponsored by Curt Volkmann

I am Curt Volkmann, President and founder of New Energy Advisors, LLC, an independent consulting firm. I work with environmental and consumer advocates in a variety of regulatory proceedings related to distribution system planning, distributed energy resources, and grid modernization. I have a BS in Electrical Engineering from the University of Illinois with a concentration in Electrical Power Systems. I also have an MBA from the University of California at Berkeley with a concentration in Finance. I have 38 years of experience in the utilities industry, primarily in electric transmission and distribution. I have previously testified before the California PUC in proceedings A.16-09-001, A.18-12-009, and A.19-08-013. Appendix 5 provides a summary of my qualifications and experience.

At the request of TURN, I estimated the likelihood of reduction in distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines resulting from TURN's proposed overhead system hardening work scope ("TURN's Scope"), which differs from PG&E's proposed scope of its overhead system hardening work. I assumed, based on coordination with TURN Witness Borden, that TURN's Scope includes the replacement of bare conductor with covered conductor; replacement of all poles, crossarms and insulators; and replacement of non-exempt fuses. TURN's Scope excludes the replacement of non-exempt lightning arrestors, transformers, services, and potheads (riser terminations).

To develop this estimate, I relied upon PG&E's spreadsheet and analysis provided in GRC-2023-PhI_DR_TURN_007-Q02Atch01. In this spreadsheet, PG&E estimates the effectiveness of its proposed overhead system hardening[168] ("OH SH") on reducing or eliminating the likelihood of various outages, which theoretically could lead to an ignition. PG&E assigned a qualitative and quantitative value of OH SH effectiveness for each outage type as follows:

[168] According to PG&E-4, pp. 4.3-19 and 4.3-20, PG&E's proposed overhead system hardening includes the installation of covered conductor, intumescent wrapped wood poles or composite poles, replacement of non-exempt equipment, replacement of transformers that do not have the now standard FR3 insulating fluid, composite crossarm, framing, and other animal/bird protections.

- All = 90% (eliminates likelihood of a certain type of outage occurring resulting in an ignition)
- High = 70% (reduces likelihood significantly of a certain type of outage occurring resulting in an ignition)
- Medium = 40% (reduces likelihood moderately of a certain type of outage occurring resulting in an ignition)
- Low = 20% (reduces likelihood minimally of a certain type of outage occurring resulting in an ignition)
- None = 0% (will not have an effect on likelihood of a certain type of outage occurring resulting in an ignition)[169]

PG&E applied these criteria to the historical outages from 2015-2018 in High Fire Threat District areas ("HFTDs"), resulting in scores for OH SH effectiveness for each outage. PG&E further narrowed its analysis by applying meteorological wind data to identify 847 outages in HFTDs that occurred during acute wind events days. PG&E grouped the 847 outages by the nine drivers of Natural Hazard, Vegetation, Distribution Line Equipment Failure, Wildfire Mitigation, Animal, Third Party, Other PG&E Assets or Processes, Human Performance, and Other.

From this analysis, PG&E projects that its proposed overhead OH SH program "will reduce 62 percent of the distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines, such as vegetation tree strikes."[170]

To determine the estimated effectiveness of TURN's Scope, I used the same outage data and methodology as PG&E and applied the following assumptions:

- For outages with Natural Hazard as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH except for outages involving transformers (reduced 70% effectiveness for PG&E's OH SH to 0% for TURN's Scope) and transformers/services (reduced from 20% to 0%).
- For outages with Vegetation as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH except for outages involving transformers (reduced from 70% to

[169] TURN_007-Q02 Atch01, tab 'Methodology & Assumptions'.
[170] PG&E-4, p. 4.3-21, lines 23-26.

0%), transformers/services (reduced from 20% to 0%), and line slap/lightning arrestors (reduced from 90% to 40%).

- For outages with Distribution Line Equipment Failure as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH except for outages involving transformers (reduced from 70% to 0%), transformers/services (reduced from 20% to 0%), line slap/lightning arrestors (reduced from 90% to 40%), and line slap/transformers (reduced from 70% to 40%).
- For outages with Wildfire Mitigation as the driver (i.e., Public Safety Power Shut-off outages), TURN's Scope has the same effectiveness (70%) as PG&E's OH SH.
- For outages with Animal as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH except for outages involving line slap/transformers (reduced from 70% to 40%).
- For outages with Third Party as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH.
- For outages with Other PG&E Assets or Processes as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH except for outages involving potheads (reduced from 70% to 0%).
- For outages with Human Performance as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH.
- For outages with Other as the driver, TURN's Scope has the same effectiveness as PG&E's OH SH.

From this analysis, I estimate that TURN's Scope would reduce 58% of the distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines, compared to 62% from PG&E's proposed OH SH scope. In other words, I estimate that TURN's Scope will provide around 93% (57.6%/61.8%)of the wildfire risk reduction benefits provided by PG&E's proposed scope. The analysis described above is summarized by driver in the following Table:

Outage Driver	Count of Driver	Average of PG&E Effectiveness	Average of TURN Effectiveness
Natural Hazard	250	33%	26%
Other	204	90%	90%
Vegetation	155	62%	60%
D-Line Equipment Failure	110	69%	56%
Wildfire Mitigation	97	70%	70%
Animal	15	79%	67%
Third Party	10	58%	58%
Other PG&E Assets or Processes	5	14%	0%
Human Performance	1	0%	0%
Total	847	61.8%	57.6%

Appendix 4. Eric Borden Statement of Qualifications

EDUCATION

Master of Public Affairs, University of Texas at Austin, LBJ School of Public Affairs, 2010-2012
Specialization: Natural Resources and the Environment
Thesis: Electric Vehicles and Public Charging Infrastructure in the United States

B.S.B.A., Washington University in St. Louis, Olin School of Business, 2002-2006
Majors: Finance, Entrepreneurship
Minor: Psychology

PROFESSIONAL EXPERIENCE

Principal Associate
Synapse Energy Economics **June 2022- Present**

Energy Policy Analyst **February 2015 – June 2022**
The Utility Reform Network (TURN)

- Prepare testimony, conduct analyses, draft comments, and represent 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.

Senior Energy Analyst **June 2013 – January 2015**
4 Thought Energy LLC, Chicago, IL
4 Thought Energy specializes in designing, installing, and operating on-site natural gas combined heat and power (CHP) systems.

- 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

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

- 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

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

Research Project Title**:** “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

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

- 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

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

- 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

PUBLICATIONS

“Clean Energy Technology and Public Policy,” LBJ Journal of Public Affairs, editor and contributor, 2011.
“Electric Vehicles and Public Charging Infrastructure: Impediments and Opportunities for Success in the United States,” The University of Texas at Austin, 2012.
“Policy efforts for the development of storage technologies in the U.S. and Germany,” DIW Discussion Paper, 2013.
“Expert Views on the Role of Energy Storage for the German Energiewende,” DIW Berlin and BMU “Stores” project, online here, 2014.
“Germany’s Energiewende,” chapter 15 in Global Sustainable Communities Design Handbook, ed. Dr. Woodrow Clark, Elsevier Press, 2014.
“Battery Storage for Renewables: Market Status and Technology Outlook,” International Renewable Energy Agency (IRENA), co-author with Ruud Kempener, 2015.

EXPERT TESTIMONY

Date	Proceeding	Testimony
4/13/15	A.14-04-014/ R.13-11-007	Testimony Regarding SDG&E's Application for Authority to Build Electric Vehicle Charging Infrastructure
5/15/15	A.14-11-003	Direct Testimony Addressing the Treatment of Solar Distributed Generation for Estimating Distribution System Capacity/Expansion Expenditures
11/30/15	A.15-02-009	Direct Testimony Regarding PG&E's EV Infrastructure and Education Program
12/21/15	A.15-02-009	Rebuttal Testimony Regarding PG&E's A.15-02-009 for EV Infrastructure and Education Program
4/29/16	A.15-09-001	Direct Testimony Addressing the Proposal of PG&E for Electric Distribution and New Business Expenditures
4/19/17	R.12-06-013	Direct Testimony Evaluating Hardship due to TOU Rates on Vulnerable Populations in Hot climate Zones
7/25/17	A.17-01-020	Direct Testimony Addressing the Proposal of PG&E for a Fast Charging Infrastructure Program
4/9/18	A.17-12-002 et al.	Prepared Testimony Addressing the Proposal of SCE for Energy Storage Procurement
8/10/18	A.18-02-016 et al.	Prepared Testimony Addressing Issues Pertaining to AB 2868 (Energy Storage)
10/26/18	A.17-12-011	Direct Testimony Regarding Potential Effects of More "Cost Based" TOU Rates and Seasonal Differentiation of Tiered Rates.
11/30/18	A.18-06-015	Direct Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal
12/21/18	A.18-06-015	Rebuttal Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal
4/23/19	A.18-09-002	Direct Testimony Addressing SCE's Grid Safety and Reliability Program Infrastructure Proposal
7/26/19	A.18-12-009	Prepared Testimony Addressing Pacific Gas and Electric's Enhanced Vegetation Management and System Hardening Wildfire Mitigation Expenditures

5/5/20	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
5/18/20	A.19-10-012	Prepared Testimony Addressing San Diego Gas and Electric's Power Your Drive 2 Electric Vehicle Charging Infrastructure Proposal
9/1/20	A.20-03-004	Joint Testimony with Eduyng Castano (SCE) Addressing Data Collection and Evaluation of the New Homes Battery Storage Pilot Program
9/4/20	A.19-08-013	Prepared Testimony Addressing Southern California Edison's Test Year 2021 Track 2 General Rate Case Memorandum Account Request – Wildfire Expenditures
4/14/21	A.20-09-019	Prepared Testimony Addressing Pacific Gas and Electric's Wildfire Mitigation Memorandum Accounts
3/2/22	A.21-10-010	Prepared Testimony Addressing Pacific Gas and Electric's Electric Vehicle Charge 2 Proposal
3/30/22	A.21-06-022	Prepared Testimony Addressing Pacific Gas and Electric's Framework for Substation Microgrid Solutions
5/25/22	A.21-09-008	Prepared Testimony Addressing the Reasonableness of Pacific Gas and Electric 2020 Vegetation Management Balancing Account Overspend

Appendix 5. Statement of Qualifications for Curt Volkmann

Professional Experience

I am President and founder of New Energy Advisors, LLC (http://www.newenergy-advisors.com/), an independent consulting firm. With 38 years of experience in the utilities industry, I work with environmental and consumer advocates across the US in a variety of regulatory proceedings related to distribution system planning, distributed energy resources, and grid modernization.

Prior to founding New Energy Advisors, I worked for the Environmental Law & Policy Center (ELPC) as a Senior Clean Energy Specialist. My work at ELPC focused on providing technical advice and expert witness testimony in several renewable energy and energy efficiency regulatory proceedings.

Prior to ELPC, I was employed for eighteen years by Accenture, a global management consulting and technology firm. I held several positions at Accenture, including Executive Director in Accenture's North America Utilities practice, with client leadership responsibilities for several gas, electric, and water utilities. In this role, I oversaw utility cost reduction and operational improvement programs.

Prior to Accenture, I worked for the consulting firm UMS Group, where I led multi-utility benchmarking studies examining global best practices in electric transmission and distribution. Participating utilities in the studies were from North America, Europe, Australia, New Zealand, and Africa.

I began my professional career working for nine years at Pacific Gas and Electric in various transmission and distribution roles. This included a role as a Distribution Planning Engineer, where I evaluated the impacts of cogeneration on distribution system protection and the impacts of demand-side management programs on the deferral of distribution substation upgrades.

Education

I have a BS in Electrical Engineering from the University of Illinois at Urbana-Champaign with a concentration in Electrical Power Systems. I also received an MBA from the University of California at Berkeley with a concentration in Finance.

I held a Registered Professional Electrical Engineer license in California from 1987 to 1995.