BEFORE THE OFFICE OF ENERGY INFRASTRUCTURE SAFETY
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Office of Energy Infrastructure Safety Natural Resources Agency

COMMENTS OF THE GREEN POWER INSTITUTE
ON THE 2026-2028 WILDFIRE MITIGATION PLAN OF PG&E

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The Green Power Institute (GPI), the renewable energy program of the Pacific Institute for Studies in Development, Environment, and Security, provides these *Comments of the Green Power Institute on the 2026-2028 Wildfire Mitigation Plan of PG&E*.

The GPI performed a review of PG&E's 2026-2028 Base Wildfire Mitigation Plan (WMP) with a focus on WMP policy design, Risk Methodology and Assessment (WMP Section 5), Wildfire Mitigation Strategy Development (WMP Section 6), Wildfire Mitigation Approaches (WMP Sections 8-9), and Integrated Distribution System Planning. Our comments focus on distribution system risk modeling, risk model applications, mitigations selection, mitigation CBA, vegetation residue cradle-to-grave and cradle-to-cradle management, and integrated distribution system planning.

I. Policy Framework: The role of the WMP and WMP review process.

A. WMPs must provide sufficient transparency and analysis to justify their proposed mitigation portfolio and validate that it achieves an optimized balance between reliability, safety/environmental protection, and affordability, for the purpose of work scope approval/modification in the GRC.

Electric utilities are authorized monopolies which build, maintain, and operate the critical infrastructure necessary to deliver power to customers in their territories. Regulatory oversight was established to safeguard ratepayers and is guided by three core, interdependent objectives: reliability, safety/environmental protection, and cost. Often referred to as the three-legged stool, failure to maintain an equilibrium will result in an unstable system that can harm ratepayers, impairs services, and undermines state initiatives.

Electrical infrastructure wildfire risk and risk mitigation sits at the nexus of the cost-reliability-safety/environment framework. What constitutes an "optimized" balance is paradigm dependent. Regulatory agencies including the OEIS, SPD, and CPUC are tasked with identifying whether utility WMPs propose methods and mitigation portfolios that result in an optimal balance of safety, reliability, and cost that serves the best interest of ratepayers.

Safety/Environment – The safety of Californians is the most apparent objective of wildfire risk mitigation—placing it at the apex of utility enterprise risk rankings. Wildfire impacts are broad and include, but are not limited to, loss of life, health impacts, structure loss, economic impacts, an exodus of insurers, increased cost of property insurance.[e.g.1,2,3,4] Environmental impacts include substantial carbon emissions that rival the very emission reductions achieved in the electric sector.[5] Safety risk drives the resurgence of Utility wildfire mitigation efforts, risk assessments, resulting reporting requirements (e.g. the WMP), and the current review process– though it cannot exist in a vacuum as an independent driver of work plan design and evaluation.

Reliability – PSPS and EPSS outage events are employed as wildfire mitigations that reduce risk only during times of elevated wildfire risk conditions. These mitigations are highly effective and have a high Cost Benefit Ratio (CBR), but also introduce reliability consequences. Mitigating system reliability risk incurred from wildfire risk mitigations must invoke holistic system designs that including distribution system overhead solutions (e.g. sectionalizing), distributed energy resources (DER, e.g. rooftop solar and energy storage), situational awareness tools, and undergrounding. This risk must also be quantified at the granular scale and directly included in mitigation section decisions to arrive at a balanced system-level mitigation portfolio.

Cost – Multiple reports highlight the high cost of wildfire mitigations and its profound influence on ratepayer bills. A 2025 Q4 report issued by Public Advocates Office (PAO) finds that 1 in 5 PG&E customers are behind on their energy bills and PG&E's average rate per kWh has increased 41 percent in the last 3-years.[6] PAO also reported that wildfire mitigation is a top statewide driver of electricity rate cost increase over the last 10-years (Q4 2023).[7] Rate base, defined as the net infrastructure investment at a specific point in time, increases with increasing wildfire grid hardening mitigations (i.e. capital expenses) that are layered onto, or replace,

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[1] CalMatters 2/11/2025, California homeowners will have to fund half of high-risk insurer's $1 billion 'bailout' https://calmatters.org/economy/2025/02/homeowners-insurance-costs-rising-in-california-fair-plan/ Accessed 4/30/2025.

[2] NewsWeek 1/10/2025 These California Insurers Cut Policies Before Devastating Wildfires https://www.newsweek.com/these-california-insurers-cut-policies-before-devastating-wildfires-2012158.

[3] OhioToday. 2/6/2025. The economics of a disaster: How the LA wildfires may impact the economy https://www.ohio.edu/news/2025/02/economics-disaster-how-la-wildfires-may-impact-economy.

[4] Northeastern Global News. 1/17/2025. As California wildfires continue to rage, smoke researchers warn of negative short-, long-term health effects https://news.northeastern.edu/2025/01/17/california-fires-smoke-impact/.

[5] UChicago News. 10/25/2022 UChicago study finds single year of wildfire emissions is close to double emissions reductions achieved over 16 years. https://news.uchicago.edu/story/wildfires-are-erasing-californias-climate-gains-research-shows.

[6] Q4 2024 Electric Rates Report. The Public Advocates Office at the California Public Utilities Commission. February 18, 2025, p. 4-5.

[7] Q4 2023 Electric Rates Report Public Advocates Office at the CA Public Utilities Commission January 19, 2024. p. 6.

existing infrastructure[8] – this increases rates for decades to come, particularly when the infrastructure investments serve existing customer load, versus new grid needs identified in the Distribution Planning Process.

Rising electric rates prompted the issuance of Executive Order N-5-24, which identifies wildfire mitigation investments as a cost driver and calls for action:

The Office of Energy Infrastructure Safety is directed, and the California Public Utilities Commission is requested, to consult with each other on adjustments to utility wildfire safety oversight processes, procedures, and practices that would yield administrative efficiencies and focus utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers.[9]

All three critical components, including cost, must be considered in every step of the wildfire mitigation regulatory process, and especially in the WMP review process before the resulting mitigation portfolio is submitted to the CPUC via the GRC or EUP. In the 2026-2028 WMP review process it is critical to ensure that the WMPs include risk modeling and application methods, granular mitigation selection criteria, and mitigation portfolio assessments which result in a transparent, cost-conscious wildfire mitigation portfolio that manages wildfire and reliability risk according to a least-cost best-fit paradigm. The WMP must provide sufficient transparency and justification necessary for the CPUC to evaluate whether the proposed mitigation portfolio correctly balances safety, reliability, and cost for the purpose of cost approval or modifications via the GRC.

PG&E's suite of risk models, grid hardening mitigations, operational mitigations, grid management methods, and situational awareness tools has advanced substantially since modern WMPs filings began. An affordable wildfire mitigation approach will require the strategic application of all available wildfire risk management tools. PG&E's overhead distribution

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[8] California Public Utilities Commission. (2024). *2024 SB 695 report*. Office of Governmental Affairs. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2024-sb-695-report.pdf.

[9] **California Office of the Governor.** (2024, October 30). *Executive Order N-5-24: Tackling Rising Electric Bills.* Retrieved May 21, 2025, from https://www.gov.ca.gov/2024/10/30/governor-newsom-issues-executive-order-tackling-rising-electric-bills/.

system hardening and operational mitigations have especially improved over time to include CC+EPSS/DCD+PSPS while also reducing the reliability impacts through sectionizing investments, improved situational awareness, updated operational mitigation thresholds. microgrids, and DER. The overhead distribution mitigation package will continue to leverage targeted PSPS events to cost-effectively prevent ignitions during high wildfire risk conditions. In contrast, undergrouding provides year-round risk mitigation for all wildfire risk drivers at a premium price, including at times when wildfire risk is low. However, undergrouding deployments must be PSPS risk informed to effectively mitigate reliability risk.

PG&E's WMP suggests that widespread deployment of an overhead distribution hardening package across the HFTD, complimented by DERs and microgrids to provide ride-through capabilities during EPSS and PSPS events, plus targeted undergrouding, especially in high PSPS risk areas, can collectively offer timely and cost-effectively wildfire and reliability risk mitigation.

B. In the absence of benchmarkable wildfire safety and reliability planning standards—WMP review must evaluate plan transparency, utility risk tolerance thresholds, and whether a least-cost portfolio has been proposed

The existing wildfire mitigation planning standard that addresses acceptable safety/ environmental risk tolerance is the elimination of utility ignited catastrophic wildfires, defined as a fire that (1) directly causes one or more deaths; (2) damages or destroys over 500 structures; [and/or] (3) burns over 140,000 acres of land. As previously identified by GPI, this planning standard (*i*) lacks a probability component, effectively asserting zero risk tolerance regardless of event likelihood and (*ii*) is not a direct output from existing wildfire risk models, meaning Utility wildfire risk models must be calibrated to benchmark against the "no catastrophic wildfire" planning standard. These planning standard design gaps make the determination of what constitutes "sufficient" wildfire risk reduction a subjective issue that utilities address through risk model design as well as application.

Acceptable wildfire risk mitigation plan benchmarking is further complicated by the lack of a reliability planning standard as it pertains to wildfire risk mitigation impacts. To our knowledge the CPUC has not defined PSPS reliability loss limitations, and no reliability planning standards have been established for EPSS related outages.e.g.[10] In the absence of adopted reliability risk planning standards, there is no benchmark for what constitutes the "acceptable" amount of reliance on operational wildfire risk mitigations, namely PSPS and EPSS, and resulting mitigation portfolio design. This is best showcased in contrast to the formally adopted system reliability planning standard which is current set at mandating energy resource capacity contracts sufficient to reduce outage risk to a 1-in-10-year Loss of Load Expectation (i.e. 0.1 LOLE; e.g. widespread blackouts). This system wide planning standard is intended to balance system reliability with cost by preventing resource capacity overbuild to the benefit of improved reliability that could come at an increased ratepayer cost. This same balancing act must be struck between safety, reliability, and cost associated with any approved wildfire mitigation portfolio.

Safety and reliability risk tolerance and planning standards also put guardrails on runaway investment costs. Risk can be minimized to a fraction of the baseline, but the marginal risk reduction cost typically increases as residual risk and net benefit decreases. Without benchmarkable risk tolerance planning standards, what constitutes a reasonable cost also becomes subjective.

The Integrated Resources Planning Proceeding implements the three-legged stool framework in a way that that is highly illustrative and relevant to wildfire mitigation plan evaluation and portfolio design assessment. The CPUC generates <u>multiple</u> possible systemwide resource capacity portfolios that are designed to simultaneously achieve (1) a reliability planning standard (1-in-2 year peak load and 0.1 LOLE, also impacts customer safety); (2) an environmental impact planning standard (30 MMT CO_2e by 2030, also impacts customer safety); and (3) other statutory requirements (e.g RPS percentage, clean energy percentage). A least-cost resource portfolio is proffered as a benchmark resource build-out scenario, with other higher-cost scenarios built to serve ancillary benefits and/or alternate possible futures (e.g. resource diversity, additional fossil fuel resource retirement, high demand scenario, more severe climate change impacts etc.). Multiple possible resource portfolios, or investment scenarios, allow

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[10] **California Public Utilities Commission (CPUC).** (n.d.). *Evolution of PSPS Guidelines*. Retrieved May 21, 2025, from https://www.cpuc.ca.gov/consumer-support/psps/evolution-of-psps-guidelines.

comparison of least-cost options to higher cost options with ancillary benefits, though every portfolio meets the minimum required reliability and environmental planning standards as determined based on direct model outputs. In general, a single formally adopted system portfolio establishes the basis for capacity procurement orders and resource attribute requirements as well as transmission investments. This system offers *transparent* alterative "mitigation" portfolios, each with a unique cost-benefits, and ultimately puts boundaries on ratepayer incurred cost. Load serving entities have some flexibility in how they satisfy the procurement order (e.g. mitigation deployment), but portfolio guardrails are already established at the system level (e.g. GRC total undergrouding miles approved).

In comparison, determining WMP and mitigation portfolio reasonableness is plagued by subjectivity due to the gaps in safety and reliability planning standards. These gaps result in open-ended interpretation of what is "enough" in terms of mitigation portfolio risk reduction, which also impacts cost. When safety and reliability risk tolerances are relatively unconstrained by the regulatory body it places risk tolerance determinations in the hands of the Utilities, which in turn can render cost reasonableness at the Utility discretion.

In the absence of these guardrails, the current regulatory framework for wildfire risk mitigation means it is up to OEIS and the CPUC together, to determine (1) Whether Utility-established risk tolerance thresholds are (*i*) transparent and (*ii*) are reasonable as defined through safety and reliability risk modeling, model application, and mitigation selection; (2) The least-cost wildfire risk mitigation portfolio needed to achieve a reasonable risk tolerance threshold (i.e. cost-benefit); and (3) Whether an alternative higher cost mitigation portfolio is adequately justified based on its marginal risk reduction, ancillary benefits, or other factors that justify the higher cost to ratepayers.

There are at least two temporary antidotes to this present challenge. First, cost offers a starting point for assessing risk mitigation reasonableness such that the first benchmark of a cost-effective design involves *starting with the least-cost* mitigation *option*. Reasonableness of higher cost options is then informed by whether there is a need to reduce *residual risk* to meet safety and/or reliability planning standards or to realize ancillary benefits deemed sufficiently impactful to warrant an increase in plan cost. The second antidote is to compare multiple mitigations and selection methods at the local-level and *transparently* report on the total cost-benefits of the resulting aggregated system-level mitigation portfolios. Regulatory agencies cannot become distribution system engineers and assess the residual risk along every circuit segment for cost-benefit reasonableness. However, summary statistics on multiple alternative aggregated system-level mitigation portfolios can elucidate residual wildfire and reliability risk in connection with portfolio cost.

C. Utility wildfire risk tolerances and mitigation solutions are informed by liability exposure and return on equity.

At a high level there are two fundamental facts critically relevant to a Utility wildfire risk reduction paradigm: (1) California Utilities face high wildfire liability exposure under inverse condemnation not just negligence; [e.g.11] and (2) Utilities are for-profit companies that are sanctioned monopolies permitted to make a profit on capital expenses (CapEx). Coupling these two facts with wildfire risk planning standard gaps equates to a regulatory cocktail that incentivizes widespread adoption of the most hands-off, effective, highest capital investment mitigation: distribution system undergrounding. Widespread primary distribution system undergrounding can address 98% of wildfire risk at a given location, which protect a utility from and shifts wildfire related liability costs to ratepayers while turning a profit for shareholders.

This is a logical for-profit business model in the given situation that equates to a utility "win-win" outcome of reduced wildfire risk (and associated liability risk) with substantial net profits. It is at the same time, an archetypical reason for regulatory oversight of utility monopolies in order to protect captive ratepayers. Minimizing wildfire risk is a win from the ratepayer perspective. However, high costs make an "undergrounding-first" approach imbalanced from a ratepayer perspective, especially for low-income ratepayers that bear the costs but not the risk. AB 1054 did prevent the IOUs from recovering return on equity on the first $5Bn in wildfire

[11] **California Public Utilities Commission, Public Advocates Office.** (2023, April 7). *Wildfire Safety and Inverse Condemnation Policy Paper*. Retrieved May 21, 2025, from https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230407-caladvocates-wildfire-safety-inverse-condemnation-policy-paper.pdf.

capital investments.[12,13] This early phase stipulation provided some ratepayer relief but has likely already been exceeded since its passing in 2019. This one-time relief should not be considered as nullifying the anticipated high cost of extensive undergrounding, associated Utility stakeholder profits, and its impact on ratepayer bills in the coming decades.

PG&E's hybrid underground/overhead system with questionable reliability outcomes raises further questions whether the portfolio is optimized to balance safety, reliability, and cost. Both risk tolerance and cost considerations must be invoked to apply the necessary regulatory checks and balances that counter Utility pressures and inducements, and to fulfill the role of regulator in ratepayer's best interests.

D. WMP must provide a sufficient basis for assessing the cost-benefit of mitigation options and resulting portfolios in the GRC.

The modern WMP filings were first initiated in the CPUC Ratesetting Proceeding R.18-10-007, which was subsequently closed in 2021 and WMP oversight was transferred to the OEIS. Since that time the regulatory roles of the CPUC and OEIS as it pertains to WMP review and approval have been increasingly clarified through WMP review cycles, updated WMP Guidelines and Processes, as well as WMP and GRC Decisions.[14,15]

The 2025 WMP Guidelines now formally include a Petition to Amend an OEIS Approved WMP to align with a CPUC GRC decision.[16] GRC Decisions have modified Utility WMP scope of work, especially total undergrounding versus overhead covered conductor miles, and the

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[12] California State Legislature. (2019). *Assembly Bill No. 1054 — Wildfires and utility liability: California Catastrophe Response Council: Wildfire Fund*. Chapter 79, Statutes of 2019. Retrieved May 21, 2025, from https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1054.
[13] "Of the $5 billion total in excluded capital expenditures, PG&E's share is $3.21 billion, SCE's is $1.575 billion, and SDG&E's is $215 million." CPUC. 2024 Senate Bill 695 Report, Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Cost Section 913.1, July 2024. p. 48.
[14] **Office of Energy Infrastructure Safety (OEIS).** (2024, March 29). *2026–2028 Wildfire Mitigation Plan Guidelines*. Retrieved May 21, 2025, p.172 from https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58026&shareable=true.
[15] **California Public Utilities Commission, Public Advocates Office.** (2016, November 23). *Public Advocates Office: PG&E General Rate Case Press Release*. Retrieved May 21, 2025, from https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/161123-public-advocates-office-pge-grc-press-release.pdf.
[16] Ibid.

associated costs.e.g.[17] These WMP plan updates and scope of work modifications help to clarify WMP evaluation and approval roles for the 2026-2028 Base WMPs.

We interpret the record to indicate that while OEIS reviews and initially approves or denies the WMPs, this process does not necessarily include approving of the scope of work itself, especially grid hardening work, which instead falls under the purview of the CPUC via the GRC. Based on these clarified roles, it is critical that the WMP review process at the OEIS determine whether the Utility has provided a transparent and adequately justified mitigation selection process that balances safety, reliability, and cost and reports the anticipated portfolio results. The WMP must at a minimum provide sufficient transparency to the CPUC to assess the cost-benefit reasonableness, enabling it to modify the scope of work as needed via the GRC in light of total energy sector needs.

WMP Approval cannot be solely based on whether the plan will reduce wildfire risk and mitigate reliability risk.e.g.[18] This framework is overly generalized does not lead to balanced safety, reliability and cost. An adequate WMP must include, but should not be limited to (1) transparent risk model design and output, (2) transparent risk model application methods; (3) transparent cost-benefit ratios; (5) sufficient information to assess the residual risk exposure and cost tradeoffs (e.g. marginal risk reduction values and cost-benefit) of location-specific overhead versus underground mitigation packages and resulting alternative system-wide mitigation portfolios. An Approved WMP must be able to inform the CPUC how and why the Utility has determined that the proposed mitigation is warranted over an alternative mitigation package, including both quantitative and qualitative justifications that consider cost, safety, and reliability factors.

Based on our review of PG&E's 2026-2028 Base WMP, this level of transparency and evaluation has not been achieved. PG&E's 2026-2028 Base WMP does not provide adequate

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[17] Pacific Gas and Electric (PG&E) GRC Proceedings (Phase I). https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/general-rate-case/pacific-gas-and-electric-grc-proceedings#:~:text=The%20decision%20approves%20key%20initiatives,$1.3%20billion%20on%20vegetation%20management.

[18] "An approved WMP demonstrates adequate progress toward wildfire mitigation, while still showing areas where the electrical corporation must improve." From OEIS Decision on 2023-2025 Wildfire Mitigation Plan, Pacific Gas and Electric Company, December 2023. P. 7.

justification that its proposed wildfire mitigation scope of work is the least-cost best-fit solution necessary to mitigate both wildfire and mitigation related reliability risk compared to alternate portfolios, or that it balances safety, reliability, and affordability. The WMP also does not provide adequate transparency for the CPUC to review the proposed mitigation portfolio cost-benefit or to modify the investment to achieve a more optimized portfolio.

GPI cautions against delaying critical revisions by issuing ACI since the Decision ACI process takes 1+ year for modifications to manifest. PG&E will have already filed its 2027 GRC application on May 15, 2025, at which point revisions to the WMP necessary to adequately evaluate the cost-benefit of their proposed scope of work in the GRC could come too late.

II. Risk Methodology (WMP Section 5).

A. Utility Wildfire risk planning models should be directly compared and should be migrated towards methodologies that ensure equitable risk mitigation outcomes and costs across California.

Over the past several years the IOUs have developed granular wildfire risk planning models and made iterative refinements in response to internal and external reviews. The SMJUs are following suit, including with the relatively recent adoption of Technosylva wildfire risk modeling products. Utilities' granular wildfire risk planning models have increasing capability for assessing location specific wildfire, EPSS, and PSPS risk, the potential for mitigations to reduce baseline risk, and subsequent mitigation selection, and therefore an increasing role. GPI supports this trend and advocates for more nuanced granular planning risk model outputs to inform mitigation selection. However, the increasing reliance on disparate wildfire risk planning models applied across California has real implications for Utility ratepayer equity.

Utilities' granular wildfire risk planning models are grid infrastructure investment decision making tools that impact electric service safety, reliability, and affordability. The model design and way in which it is applied will determine what ratepayers within a utility territory are charged, and what a subset of those ratepayer's experience in terms of reliably and safety in association with their electric service. Substantive differences between utility granular wildfire risk planning models can result in disparate ratepayer safety, reliability, and affordability between California Utilities.

This is exacerbated by the lack of a comprehensive statewide electric utility wildfire risk planning standard and associated risk tolerance that directly relates to and is informed by available modelling capabilities. The existing risk-informed planning standard, to eliminate Catastrophic wildfires, is not a specifically quantifiable output of the Utility wildfire risk models or Technosylva model packages. It also establishes an impossible to achieve and potentially extremely costly, "no risk tolerance" stance. Achieving an electrical system with zero wildfire risk is not technically feasible, even in an extreme case if the entirety of the system is undergrounded. Consequently, each utility must develop their own internal wildfire risk tolerance and planning standard driven by their liability position in the absence of a formally adopted electric utility wildfire risk planning standard that applies to all Utilities. One avenue that utility-specific wildfire risk tolerance informs and manifest through is granular planning risk models.

It is highly likely that utility wildfire risk planning models would produce very different risk values for a given location despite having the same or similar system and environmental inputs. Since the utility wildfire risk planning models inform mitigation selection and infrastructure investments—they influence the outcome of ratepayer safety, reliability, and associated cost. Differences in risk-informed mitigation type and siting decisions due to risk planning model and model application method differences may therefore be leading to inequity between California ratepayers.

Meaningful, incremental planning model alignment efforts without quantitative model alignment insights is challenging at best and futile at worst. For example, universally ordering a refresh rate and forecast duration for the Technosylva 2030 fuels layer may have different impacts when applied in each model. PG&E reports that it uses 2030 fuels in its WFC v4 model. However, only its Technosylva inputs use the 2030 fuels layer, while the FPI model relies on pre-fire fuels data. Ordering PG&E to update the 2030 fuels layer may have a different impact on its risk planning model output compared to SCE, whose 2023 risk planning model derived its consequence metrics directly from 8-h Technosylva simulation footprints based soley on 2030 fuel data. This is only one example of how revising a seemingly "consistent" utility input can have highly variable downstream impacts on risk model output and mitigation selection. Put simply, attempts to incrementally unify disparate utility wildfire risk planning model inputs and methods introduces a risk of unintended and inconsistent impacts on utility risk location and magnitude—putting model alignment efforts at a veritable gridlock.

The Utilities should be ordered to compare wildfire risk planning model outputs and resulting mitigation selections. This analysis will provide a first step towards assessing any possible inequities between utility ratepayers caused by risk planning models and model application methods. Results will provide critical insights as to whether utility wildfire risk planning model alignment should take priority over incremental buildout and iterative improvements. This should be achieved by creating unified test circuit data packages that include representative of wildfire risk regimes (e.g. fuel versus wind-driven, different fuels). GPI suspect this is a non-trivial exercise that may take 1+ years to complete in addition to ongoing WMP activities. However, its relevant to informing whether or not Utility risk planning models should be better aligned and if so, how. It will also provide a measure of whether existing methods are achieving equitable ratepayer safety, reliability, and affordability across California as it applies to utility wildfire risk planning. GPI is concerned that without this assessment, or a similar effort, the WMP review and RMWG efforts to align utility risk models and ensure equity across California ratepayers may come to a standstill.

B. WFC Model: Other yet to be modeled consequence inputs should not be incorporated into existing utility planning risk models until they minimally aligned across IOUs and reviewed by a third-party, regulatory agencies, and stakeholders. Preferably these models would be jointly developed or developed in collaboration with state agencies.

GPI is concerned that prematurely ordering the incorporation of additional wildfire risk consequence factors into Utility wildfire planning risk models may have (*i*) unintended and perhaps undesirable utility risk-informed mitigation consequences, (*ii*) may not inform the optimal mitigation from a holistic mitigation paradigm, and (*iii*) will result in further divergence of utility consequence model methodologies and outputs. We use wildfire smoke consequence as a case study.

(*i*) Prematurely ordering the incorporation of additional wildfire risk consequence factors into Utility wildfire planning risk models may have unintended and perhaps undesirable outcomes for utility risk-informed mitigation selection. For example, smoke and associated health risk modeling may meaningfully shift the relative spatial distribution and scaling of utility wildfire consequence. Whether the shift aligns with and addresses agency-guided wildfire risk mitigation objectives should be determined *before* the model is put into play.

E3 hypothesizes that smoke related consequence would be more concentrated in highly populated areas and could result in the de-prioritization of mitigations in rural areas with high PoI. GPI is concerned that the opposite could be true. Wildfires that occur in more rural areas that are harder to access could result in larger burn footprints and concomitant increased smoke production. Regardless of WUI proximity, windy conditions often associated with the largest fires and acreage burned, also transports smoke. Transport distance and whether the smoke collects in an air basin characterized by high density population will have an impact on the resulting consequence.

Washoe County and the Reno/Sparks, NV area is one example of a populated area that collects and is significantly impacted by California wildfire smoke.[e.g.19] As a recent example, prescribed burns conducted on May 7, 2025 in the relatively remote and unpopulated Dog Valley, CA, between the Verdi Range and Crystal Peak just north of Stampede Reservoir, resulted in 5 consecutive hours of "Unhealthy" (AQI scale) air quality across Verdi and northern Reno/Sparks, NV (EPA AirNow AQI).[20] In this example, a remote and managed fire had an impact on out-of-state air quality in a population center upwards of 27+ km away. It is possible that a smoke consequence model could elevate the consequence of potential ignitions in more remote locations on a utility's grid by tying its risk to distant and even out-of-state population centers.

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[19] Reno makes worst air quality list in annual report card. April 30, 2024. https://thisisreno.com/2024/04/reno-makes-worst-air-quality-list-in-annual-report-card/.
[20] Prescribed Burn Leaves Downtown Reno Smoky Wednesday Morning. https://www.rgj.com/story/news/2025/05/07/reno-is-smoky-today-when-will-the-prescribed-burn-be-done/83492648007/.

In the case of PG&E's WFC, the consequence scores reflect relative risk across its territory and location specific risk is converted to a risk cost based on the Enterprise Risk Model. If smoke consequence is included in the WFC but not the Enterprise Risk Model value the meaning of the consequence score becomes increasingly convoluted.

(*ii*) Identifying the mitigations that best address some consequences may benefit from a state level assessment. For example, it may prove necessary to consider whether shifting costly electric infrastructure mitigations or increasing the scope of grid hardening work is the optimal mitigation for reducing smoke consequences versus allocating funds to other mitigations, such as fuel treatments. Method development may also require a determination of whether California ratepayers should shoulder the costs of mitigations informed by consequences incurred by non-California residents (e.g. NV). Alternatively, including health impacts and loss of life due to smoke may better inform wildfire mitigations that benefit Californians more broadly, beyond WUI residents. Or, the resultant model could show that existing utility wildfire risk planning models and resulting risk-informed mitigations will effectively reduce wildfire risk and associated smoke impacts without needing to add model complexity and the associated uncertainty. These issues include policy questions that are best explored after a granular wildfire consequence model is developed that is compatible with an ignition point-based consequence assessment, and the quantitative outcomes can be considered prior to integration into risk planning models.

(*iii*) An order issued to one IOU to include a model wildfire consequence element in their risk model should be extended to the other IOUs. In this case study, ordering all three IOUs to incorporate smoke impacts in their planning risk models would invariably lead to three different model methodologies. Aside from the complexity of analyzing upwards of six different models every WMP cycle, this divergence also makes it increasingly difficult to standardize utility risk model methods and inputs—which is a detriment to ensuring equitable utility wildfire risk reduction and associated costs for Californians.

GPI has previously highlighted the issue of IOU model development, adoption, and application all before external reviews are completed by third parties, regulatory agencies, and stakeholders. This process puts the cart before the horse time and time again and favors a utility paradigm.

Because of the possible complexity and uncertainty of the outcome, as well as a lack of top-down modeling, care should be taken to ensure that new utility sub-models are reviewed by a third-party, regulatory agencies (e.g. OEIS, CalFIRE, CARB, CPUC), and stakeholders, prior to their application. That is, the methodology should be reviewed and its influence on wildfire risk planning model output should be evaluated before being applied to utility wildfire mitigation selection.

Our position is in alignment with MGRA and E3's concerns regarding the relevance of smoke and other consequence modeling to wildfire risk in general, though we recommend:

- Yet to be modeled consequence inputs should not be developed separately by each IOU. Future wildfire consequence model "add-ons" should minimally constitute a joint-IOU design or preferably be developed by or incorporate inputs from California agencies such as CARB.
- New consequence inputs should not be incorporated into applied utility planning risk models until the method is reviewed by a third-party, regulatory agencies, and stakeholders, and is deemed to result in outcomes that are in alignment with state policy objectives as well as ratepayer safety and affordability goals.
- New wildfire consequence models should be timely initiated by regulatory agencies to prevent the development of disparate models by IOUs in advance of agency action.

C. WFC Model: PG&E should be ordered to remedy transparency and reporting gaps for the WFC model.

PG&E's WFC model quantifies relative (i.e. not absolute) granular CoRE scores. The CoRE value has a substantive influence on the granular wildfire risk planning model output (i.e. WDRM). PG&E outlines their WFC model methods in the supplemental wildfire-consequence-model-documentation-v4.pdf file.[21] The provided documentation is a substantial improvement from prior reporting (i.e. the 2023-2025 WMP). However, key elements of the WFC model method are missing from the documentation, including regarding Technosylva fire spread simulations, MAVf design, and FPI inputs. GPI was unable to find clarifications for questions

[21] Wildfire Consequence Model Version 4 (WFC v4) Documentation, Prepared By: PG&E Risk and Data Analytics Team. Rev. 3/12/2025. https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/wildfire-consequence-model-documentation-v4.pdf.

regarding these design elements in the WMP plan or supporting documentation. Data Requests addressed some, but not all missing WFC design summaries.[22,23]

The 2026-2028 WMP guidelines specifically require all Utilities to include:

> The process used to combine risk components must be summarized for each relevant risk component….If the electrical corporation uses scaling factors (such as Multi-Attribute Value Functions (MAVF) or representative cost), it must present a table with all relevant information needed to understand this procedure (including each scaling factor used, the value of the scaling factor, how it is utilized, an explanation of its purpose, and a justification for the value chosen). The electrical corporation must organize this discussion into the following two subsections focusing on likelihood and consequence.[24]

And

> The electrical corporation must discuss how it calculates the consequences of a fire originating from its equipment…[25]

While Data Requests may have filled in some gaps, the 2026-2028 WMP should be required to meet the reporting requirements. The WFC model documentation should not include major methodological reporting gaps. PG&E should be required to revise its 2026-2028 WMP and associated documentation to include at least the following information:

- The MAVf scaling factors used to determine granular CoRE values, and any other risk modeling output.
- All MAVf cost valuations for wildfire and reliability consequence quantification (e.g. the cost per outage minute).
- Clarify the MAVf units used throughout the WFC documentation. Specifically, whether the reported units are normalized to $1M per MAVf unit (e.g. 12.5 units per fatality), or are standard units (e.g. 1 fatality or 1 structure)
- The vintage (e.g. year/quarter) or forecasted (e.g. 2030) fuel layer used in the FPI daily backcast for the 11 historical fire seasons.

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[22] WMP-Discovery2026-2028_DR GPI_PGE_2026-2028WMP_01.
[23] WMP-Discovery2026-2028_DR_OEIS_001_Q24.
[24] **Pacific Gas and Electric Company.** *2026–2028 Wildfire Mitigation Plan (WMP), Volume 1.* April 4, 2025. p. 89.
[25] Ibid. p. 97.

- The number of worst weather days modeled in Technosylva fire spread simulations and the number input into the WFC (e.g. if a subset of total simulations). If a subset was used in the WFC, how those simulations are selected from the total worst weather days modeled.
- The FPI version applied in WFC v4.
- Justifications for the above model design elements. This is a critical component in complex model design that ultimately informs granular risk scores and CBRs.

D. WFC Model: The validation of 24-hour Technosylva match drop simulations included in the WFC documentation does not align with how simulation results are applied to inform consequence.

In WFC v4, PG&E conducts granular 24-h Technosylva fire spread simulations for 571 worst weather days selected from a 17-year (MAR 2003-DEC 2020) dataset and uses the flame length and spread rate output as a determinate of location-specific Predicted Destructive [fire] Potential (PDP).[26] In the 2023-2025 WMP (WFC v3.4), the 8-h Technosylva simulation flame length and spread rate thresholds for PDP classification were set to >=5 and >=12, respectively, based on a calibration to historic "Destructive" class fires.[27]

The same PDP prediction method is utilized in WFC v3.4 and v4 with two major differences, a change from 8-h to 24-h Technosylva simulations and improved ignition point location accuracy. For WFC v4, PG&E justifies its use of 24-h versus 8-h Technosylva simulations based on an improved correlation between the acres burned in Technosylva's 24-h simulated historical fire spread results and the actual fire outcome. The correlation improvement was relatively small, increasing from 0.198 and 0.208 for 8-h and 24-h simulations, respectively.[28] The associated figures provided in the WFC v4 documentation have incongruent x- and y-axis scales that *visually* suggest a linear 1:1 correlation on a log-log plot. The analysis indicates an improved relative (i.e. not absolute) risk correlation between Technosylva simulated acres burned and actual acres burned.

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[26] **Pacific Gas and Electric Company (PG&E).** *(2024). Wildfire Consequence Model Version 4 (WFC v4) Documentation.* Retrieved May 21, 2025, p. 15-16 from https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/wildfire-consequence-model-documentation-v4.pdf.

[27] **Pacific Gas and Electric Company (PG&E).** (2023, December 15). *2023–2025 Wildfire Mitigation Plan, Revision 5.* p. 173.

[28] **Pacific Gas and Electric Company (PG&E).** *(2024). Wildfire Consequence Model Version 4 (WFC v4) Documentation*. p. 13.

GPI appreciates PG&E's analysis as an indicator of 24-hour versus 8-h simulation application in wildfire risk planning models in general. However, more work is needed to assess the correlation between historical wildfire outcomes and Technosylva wildfire spread simulation duration for structures burned and associated loss of life as well as for relative versus absolute risk valuation in applied utility risk planning models in general. Structure loss and resulting loss of life estimates (i.e. from the MAVf) are core consequence metrics that should be considered. In general, more work should be done to elucidate the correlation between Technosylva 24-h versus 8-h simulations and historic fires as it relates to utility wildfire risk planning model applications, relative versus absolute risk, and downstream CBR application.

The primary issue, however, is that the WFC sources granular consequence values—such as acres burned, structures burned, and loss of life – based on *binned and averaged historical wildfire outcomes*, not Technosylva simulations. To our knowledge, WFC (V3.4 and v4) does not utilize Technosylva simulation outputs for acres burned or structures damage in any of its risk models. Therefore, using comparisons between historical and simulated acreage burned to justify the use of 24-hour versus 8-hour Technosylva simulations within the WFC framework is scientifically invalid. The use of 24-h versus 8-h Technosylva simulations as a WFC input for determining PDP class must be validated based on simulation flame length and fire spread output. The correlation of 24-h Technosylva simulation flame length and fire spread output with "Destructive" historical fire status must be confirmed. The respective flame length and rate of spread Predictive Destructive Criteria thresholds (PDP, >=5 and >=12) must also be confirmed as a valid calibration. Other Technosylva simulations outputs and their correlation with historical wildfire outputs, while generally relevant to risk model application, are not directly relevant to the WFC design.

GPI recommends issuing PG&E a Revision Notice that requires it to report on (*i*) any differences between 24-h versus 8-h Technosylva simulation flame length and rate of spread outputs used in the WFC; (*ii*) Provide an updated calibration figure showing changes to, or consistency with, 2023-2025 WMP Figure PG&E-6.2.2-7 "Technosylva Simulation and Destructive Fire Relationship";[29] and (*iii*) If the correlation between flame length (>=5) and rate of spread (>=12)

[29] PG&E *2023–2025 Wildfire Mitigation Plan, Revision 5*. p. 173.

has changed due to using 24-h simulations, complete and report on any necessary WFC v4 revisions and WDRM mode outputs.

PG&E's WMP, which relies on the WFC to inform CBR and resulting mitigation selections, should not be approved until a WFC relevant calibration is provided for its use of Technosylva 24-hour simulations.

E. WFC Model: PG&E's consequence model is a chimera of seasonal and worst weather inputs; driven observationally by an FPI backcast but possibly amplified by worst weather day simulations.

The updated WFC v4 model is revised to include three consequence covariates: HFTD ownership, Dry Wind Condition, and Predicted Destructive Potential (PDP). A PDP classification corresponds to the highest wildfire event consequence scores, which are derived by averaging qualifying historic wildfires for the respective fire classes.[30] The WFC determines PDP based on FPI (>=R4) OR Flame Length (>=5) AND Rate of Spread (>=12), all of which were calibrated to historic "Destructive" fires in the 2023-2025 PGE WMP based on FPI 4.0 and 8-h Technosylva simulations. FPI values are generated from a backcast of 11 wildfire seasons (n=2,013 per CoRE pixel, 2012-2022, Table 1).[31] Flame Length and Rate of Spread are outputs of Technosylva fire spread simulations conducted for 571 worst weather days (MAR 2003-DEC 2020, Table 1).[32]

GPI detailed concerns regarding this model design in our May 2022 comments on PG&E's 2023-2025 WMP.[33] E3's August 2024 review of PG&E's WFC v4 subsequently identified the same issues.[34] We reiterate and expand on our original concerns. The consequence score is a chimera of weighted and summed lower granularity historic fire season conditions (FPI) and more granular worst weather days. The effect is spatial smoothing and potentially risk amplification that is decoupled from WUI structure density. Applying FPI and Technosylva simulation

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[30] PG&E *Wildfire Consequence Model Version 4 (WFC v4) Documentation*. p. 16.
[31] Ibid, p. 30.
[32] **Pacific Gas and Electric Company.** (2025, April 21). *Wildfire Mitigations Plans Discovery 2026–2028: Data Response to OEIS-P-WMP_2025-PG&E-001, Question 024.*
[33] Comments of the Green Power Institute on the 2023-2025 Base Wildfire Mitigation Plans of the IOUs, May 26, 2023, pp. 46-49.
[34] E3 Review of PGE Wildfire Risk Model Version 4, August 2024. p. 12.

outputs to determine PDP classification filters out many location-specific consequence risk drivers resulting in very relativistic baseline consequence score driven by the number of FPI R4+ observations and possibly amplified by worst weather day Technosylva simulation inputs.

To combine FPI and Technosylva simulations into a PDP classification approach, the WFC must dispose of all the granular benefits of Technosylva's model inputs and outputs, using only flame length and spread rate. While all utilities are employing Technosylva simulations, large variations in their application are a hinderance to model standardization. This use of Technosylva simulations diverges significantly from other utility risk planning models that leverage Technosylva's granular 2030 fuels, structure, and other data sets to directly inform wildfire consequence.

Wildfire consequences in the WFC are instead based on 8 binned wildfire classes with Base Consequence values derived from the average of qualifying historical fire consequences. This is an improvement from the previous 4 wildfire classes. However, the consequence of each of the historic wildfires is a function of many location-specific factors such as proximity to structures and population density (e.g. WUI), suppression access, etc. These location specific consequence drivers are distilled down to just three covariates (previously two in v3.4), resulting in spatial smoothing based on the 8 possible "baseline" consequences. For example, none of the wildfire class covariates directly consider consequence outcome due to structure proximity. The averaged historic consequence value generated for each bin smooths out high versus relatively lower consequence historic wildfire events, flattening the baseline consequence score.

Table 1. WFC Predicted Destructive [Fire] Potential (PDP) basis

Data Year	Fire Seasons	Total Observations (n)	Data Source	Fuels Layer and Source	Fuels Layer Resolution	Fuels and Structure Layer Inputs	Has a burnable structure layer?	Selection Basis	Predicted Destructive [Fire] Potential (PDP)
MAR 2003-DEC 2011	9	<571 [4]	Technosylva Simulations	2030 Forecast; Technosylva	30m [1]	7+ [1]	Yes	Worst weather days	Flame Length (>=5) AND Spread Rate (>=12)
JAN 2012-DEC2020	9	<571	Technosylva Simulations	2030 Forecast; Technosylva	30m	7+	Yes	Worst weather days	Flame Length (>=5) AND Spread Rate (>=12)
2012-2020	9	1647	FPI 4.0	Pre-Fire Fuels Snapshot [3]	aggregated to 2x2 km	6 [2]	"Urban" fuel type, previously considered "unburnable"?	All Fire Season Days	FPI-R (>=R4)
2021-2022	2	366	FPI 4.0	Spring 2021 and 2022 fuels snapshot [3]	aggregated to 2x2 km	6	"Urban" fuel type, previously considered "unburnable"?	All Fire Season Days	FPI-R (>=R4)

1. 2026-2028 PGE WMP, p. 470
2. 2023-2025 PGE WMP, p. 778
3. WMP-Discovery2026-2028_DR_GPI_001-Q002
4. WMP-Discovery2026-2028_DR_OEIS_001_Q24

The next layer of spatial and peak smoothing is introduced through the FPI backcast. The FPI backcast includes approximately 3.5 times more observations than Technosylva simulated worst weather days. This weights the base consequence towards the 2,013 seasonal FPI observations that include low likelihood high consequence as well as high likelihood lower consequence days. The WFC v4 reports the FPI daily R-score input is modeled at a 2x2 km resolution.[35] FPI 5.0 has an improved resolution of 0.7 km^2 hexagons.[36] However, WFC documentation states that no significant updates were made to the FPI-R method between WFC v3.4 and v4 and FPI 5.0 is not mentioned in the WFC documentation.[37] Assuming the WFC applies FPI 4.0 or earlier, 400 100x100 m CoRE pixels fit within one FPI 4.0 pixel. Meaning all 400 CoRE pixels would receive the same FPI-based PDP designation for a given wildfire season day. Dry Wind classifier data resolution is not provided, though FPI 5.0 is reported as trained on 2x2 km climatology data.[38] Only the HFTD covariate is likely determined on a 100x100 m scale. We interpret this to mean that two of the three consequence score covariates are evaluated on a 2x2 km resolution. Within each 2x2 m FPI + Dry Wind pixel, consequence scores are differentiated based on HFTD ownership. The input of 2,013 FPI R-scores into each CoRE pixel results in spatial smoothing. In contrast, Technosylva simulations are modeled at a 100 x 100m resolution.[39]

The FPI application also diminishes the influence of a 2030 fuels layer forecast on consequence. The 2030 fuels layer is generated by Technosylva and is included in IOU risk planning model fire spread simulations. This data layer is largely intended to capture vegetation succession through 2030 in existing fire scars at the time the data layer was developed. However, PG&E's FPI backcast utilized three different pre-fire fuel data layers. The HFTD may use yet another fuel layer. CoRE scores are based on up to 5 different fuel datasets, including 2030 fuels and pre-fire fuels data. This design choice makes the meaning of WFC CoRE values even more convoluted. WFC granular consequence scores provide no clear insight into wildfire consequence based on anticipated versus past fuel conditions. This has implications for the

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[35] PG&E *Wildfire Consequence Model Version 4 (WFC v4) Documentation*. p. 15.
[36] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025 p. 465.
[37] PG&E *Wildfire Consequence Model Version 4 (WFC v4) Documentation*. p. 15.
[38] Ibid, p. 466.
[39] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 93.

relevance of WFC CoRE values as fuels change (e.g. burn scars expand and experience vegetation succession).

However, it is difficult to discern how much relative influence FPI has on the total consequence quantification (n=2,013) compared to *worst weather day* Technosylva simulations (n=571). While there are fewer Technosylva simulation events compared to the FPI backcast, the worst weather day simulations are presumably more likely to result in a "PDP" designation. The integration of Technosylva worst weather day simulations likely has a territory wide consequence elevating effect. For example, if all 571 worst weather day Technosylva Simulations result in a PDP qualifying Flame Length (>=5) AND Rate of Spread (>=12), the maximum and minimum Base Consequence score contribution in the HFTD would range from 286,642 to 102,780. Adding this score to the CoRE value could dwarf the summed FPI-based consequence scores which approximate consequence exposure over 11 wildfire seasons (i.e. low and high consequence days). It is also mathematically unsound to sum maximum consequence (Technosylva worst weather simulations) and probabilistic consequence (11 season FPI backcast) events into a single, total consequence value.

For the total WFC data input window (2003-2022), different timeframes have different data sources. Fire season days from 2012-2020 have both FPI and Technosylva simulations, either of which could qualify the day as a PDP fire type. Worst weather days from 2003-2011 only have Technosylva simulation outputs, so this unknown subset of the total 571 fire spread simulations will likely increase the contribution of PDP-type consequences, elevating risk across the territory. *This is roughly equivalent to adding maximum consequence tail risk or outliers to the total CoRE score.* PDP-consequence values for years 2021-2022 are only informed by the FPI backcast and will approximate wildfire season consequence exposure. Multiple model design elements cannot be discerned from the WFC documentation, such as: (i) The total number of unique days that informed each CoRE pixel consequence score, (ii) The proportion of worst weather day fire spread simulation inputs relative to FPI R-scores that determine PDP condition; and (iii) The relative influence of FPI R-scores versus Technosylva worst weather day simulations on total granular CoRE values.

The granular Base Consequence results are a hodgepodge of consequence likelihood (maximum and seasonal), spatial resolution inputs, and fuel layer vintages. The consequence values are also largely decoupled from location-specific MAVf metrics (i.e. acres burned, structures destroyed, fatalities and injuries). WFC spatial and peak smoothing as well as consequence elevating design features take relative consequence modeling to the extreme. The question must be asked whether the WFC Base Consequence method offers actionable insight for the selection of long-term mitigation investments that address specific locational risk while minimizing cost (i.e. maximum CBR).

As the WFC documentation notes, the Suppression and Egress/Ingress models further flatten the consequence distribution. The Wildfire Suppression Impact Model derives a Terrain Difficult Index (TDI), Wind Speed, and Live Fuel Moisture based regression for historical fire data. Consequence adjustments are largely driven by TDI and the driver is identified as limited suppression access resulting in increased structure loss. The wildfire egress model is based on AFN as an indicator of population vulnerability and egress ability. A TDI-AFN decile adjustment is applied to each historical wildfire and the matrices are averaged together for each fire regime. These form the basis of the location specific consequence values according to TDI, AFN and the fire type classifications. This is roughly the equivalent of setting system average consequence baselines, or "weights," for each fire regime and modifying it based on location specific TDI and AFN decile.

Based on WFC v4 PG&E states that it "…now requires considerably more primary overhead conductor miles to account for 80% of the High Fire Threat District (HFTD) wildfire risk, increasing from 10,000 miles for WDRM v3 to 14,600 miles for WDRM v4." The WFC output leans heavily towards a relative consequence model with many spatial and peak smoothing functions as well as consequence amplifying design features. PG&E acknowledges the WDRM v4 model as a relative, not absolute risk, model.[40] While this hedges against false precision, its combination of disparate data granularities, historical fire averaging, combined fire season and worst weather days, inconsistent fuel layers, and extreme distillation of local attributes throws into question what the resulting CoRE values actually mean in terms of PG&E's risk tolerance

[40] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, Appendix B p. 650.

and planning standard. It seems that the most the WFC v4 scores can inform is “more” or “less” risk at a ~2x2 km resolution.

Grid hardening mitigations do not directly influence ignition consequence. However, the CBR is highly influenced by wildfire consequence and does directly inform mitigation infrastructure investments. Selecting 10,000+ miles of undergrouding (~$3M per mi) versus overhead mitigations (~$1M per mi.) based on “more” or “less” wildfire risk is not a sufficient or transparent basis for balancing ratepayer safety, reliability and cost. The WFC should be found deficient, and PG&E should be ordered to reduce the number of spatial smoothing and peak flattening functions in its WFC, as well as improve the spatial granularity, location-specificity, and functional meaning of its consequence scores. Model revisions should result in a more transparent and meaningful risk tolerance basis and granular CBR for the purpose of mitigation selection. This is also an opportunity to bring PG&E’s consequence model into closer alignment with other IOUs, for example by requiring it to base its consequence model on the 2030 fuel forecast.

Some relevant and applicable detail could be restored by disaggregating the WFC score based on fire regime and PDP classifier. For example, avoid combining FPI and Technosylva informed consequence scores into a single consequence value. Plot the consequence scores for each fire regime, with FPI as a PDP classifier (11 fire seasons). Separately plot consequence scores based on Technosylva worst weather day simulations (18-year data set).[41] Technosylva worst weather day consequence scores could revert to the rich location-specific, MAVf-relevant fire spread model outputs, including acres burned and structures damaged. Assessing disaggregated FPI-based and Technosylva worst weather day consequence scores separately would provide a more nuanced picture of typical fire season consequence exposure as well as maximum consequence based on location-specific attributes.

We offer this as an alternative to E3’s suggestion to include model uncertainty. GPI supports E3s recommendation to include uncertainty in wildfire risk model outputs, including in the WFC. However, we are also concerned that it may be difficult to quantify uncertainty in the

[41] Assuming the fire spread and flame length correlation with Destructive fires is still applicable to 24-h simulations.

WFC and WDRM as a whole and uncertainty may be large. Adding new consequence components (e.g. smoke) may also increase model uncertainty.

III. Wildfire Mitigation Strategy (Section 6): Risk Model Application.

Risk model application methods and CBRs are the critical steppingstone linking granular risk model output to location-specific mitigation selection, which aggregate to a territory wide mitigation portfolio. PG&E's utility risk tolerance, model application approach, and undergrouding first paradigm determine the CBR of its location specific mitigations and the system portfolio as a whole. Therefore, regulatory oversight of PG&E's proposed risk model application methods is key to guiding long-term investments that maximize CRB and balance safety, reliability, and affordability. Our comments focus on distribution system risk planning models and mitigations unless otherwise noted.

A. PG&E should not be allowed to set a total cost cap and then allocate it in a top-down manner to define the scope of wildfire grid hardening.

E3's review of PG&E's wildfire risk model states:

> Currently, PG&E is setting total wildfire mitigation budgets for business units using a top-down approach that starts from a total budget and is allocated to business units based on their relative wildfire risk as measured by number of ignitions. … E3 recommends that PG&E take steps towards using outputs from its risk models to inform the total budgets for risk mitigation, justify proposed mitigation measures, and to more optimally allocate funds based on findings.[42]

GPI strongly agrees with this statement and expands on this E3 recommendation. The OEIS should not permit PG&E to set a total wildfire mitigation budget that is subsequently allocated, top-down to wildfire mitigation related business units. The total budget needed to mitigate wildfire risk should be based on the least-cost best-fit mitigation portfolio necessary to achieve a transparent risk tolerance-based planning standard informed by granular risk planning model results. The purpose of granular risk planning models is to inform the location specific types and resulting aggregated scope (i.e. miles) of grid hardening needed to mitigate risk; not the first and next best locations to deploy a pre-determined scope of work.

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[42] E3 Review of PGE Wildfire Risk Model Version 4, August 2024.

The top-down method and a percentage of top risk ranked circuits informed PG&E's original long-term target for 10,000 miles of distribution undergrouding (8,000 overhead miles). PG&E's initial underground deployment criteria in its 2026-2028 WMP is based on "Geographic Area 1: Top Risk Areas based on Wildfire Risk Models (HFTD/HFRA)."[43, 44] Some locations are incompatible with undergrouding (e.g. hard rock, steep grades, water crossings).[45] Based on PG&E's top-down budget allocation method and a fixed total undergrounding scope of work, undergrouding miles initially planned for incompatible locations will be relocated to locations with lower wildfire and reliability risk, therefore resulting in lower CBRs. This methodology directly breaches the core tenants of *balancing system reliability, safety, and cost*, as well as *least-cost best-fit investments*. PG&E should not be permitted to pre-determine a total mitigation budget. PG&E should also no longer be permitted to determine its undergrouding scope of work on a top risk percent and should instead be required to develop a mitigation plan based on a transparent and verifiable planning standard.

We use existing CPUC regulated processes as an example. Integrated Resource Planning (IRP) process does not presuppose a total budget for new resources needed to meet the CAISO-wide reliability planning standard, nor does it subsequently allocate the cost, top-down, to different resource types. This method would directly breach the core tenants of affordable system planning. Rather, the IRP "risk reduction model" first includes existing resources (i.e. existing risk "mitigations"), second, it adds least-cost resources (i.e. new "mitigations") until the value of these resources saturates (i.e. its *marginal* value to the system declines, until the CBR is too small to warrant further additions), and third, it adds or substitutes in higher cost resources until the reliability planning standard (i.e. acceptable risk tolerance) is achieved. The bottom-up "risk mitigation" portfolio construction follows a least-cost, best-fit paradigm and right-sizes each "mitigation" technology based on its marginal value to the system. The marginal CBR of layered "mitigations" drives the final portfolio composition and cost. Exchanging least-cost resources with higher cost resources in an alternate portfolio (i.e. solution) must generally be justified based on either addressing residual risk that exceeds risk tolerances or providing

[43] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025. Table PG&E-6.1.3.2-1, p. 133.
[44] WFC v4 flattens the risk buydown curve to include 14,600 overhead line miles within the top 80% of HFTD/HFTD risk, versus 10,000 miles. See wildfire-consequence-model-documentation-v4.pdf, p. 1.
[45] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025. p. 118.

ancillary benefits.[46] Multiple bottom-up alternative "risk mitigation" portfolios are produced that have a range of "risk reduction" outcomes and costs. These multiple risk mitigation portfolios ultimately present options with variable reliability-safety/environmental-cost tradeoffs. A single portfolio is then selected to balance ratepayer affordability, realize ancillary benefits, achieve emission reduction goals (i.e. safety/environmental), and satisfy the reliability standard.

PG&E should be required to employ a similar bottom-up approach that informs the total grid hardening mitigation budget. The bottom-up approach must be designed to achieve least-cost best-fit principles and balance safety, reliability, and affordability considerations. It must be guided by a transparent risk-based planning standard that includes quantifiable granular and system-wide risk tolerance thresholds informing what constitutes "sufficient" and "done." It must also employ marginal cost benefit ratios at the local scale that consider baseline risk as well as existing mitigations (i.e. ratepayer investments) and their cost-benefit contribution. Targeted ancillary benefits must be transparent and adequately justified if they are leveraged to select a higher cost mitigation (e.g. system future proofing). With a bottom-up paradigm, least-cost complimentary mitigation packages (i.e. an overhead mitigation package) should be layered onto existing mitigations where the residual risk exceeds the risk tolerance. If the residual risk still exceeds risk tolerances, an alternative higher-cost mitigation should be considered (i.e. undergrounding). We put this into context with PG&E's mitigation selection method, below.

B. Grid hardening investments scoped in the WMP cannot be justified based on reliability risk drivers that are independent of wildfire risk or wildfire risk mitigations (i.e. PSPS and EPSS).

PG&E states (emphasis added):

> PG&E continues to prefer undergrounding on high-risk circuits where feasible for several reasons…Underground facilities are less likely to be damaged during winter storms by high winds and vegetation falling into lines damaging the facilities or other contact with the lines from third parties…[47]

[46] For example, biomass facilitates to provide a renewable disposal pathway for dead and dying tree residues, or more costly 12-h+ batteries to provide resource diversification and serve load during extended periods of low solar or wind generation, or during heat waves.
[47] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 134.

PG&E partially justifies its preference for Undergrouding based on mitigating damage incurred from winter storms, when wildfire risk is generally low. Safety and reliability risk incurred from winter storm damage are not synonymous with wildfire risk. Mitigating winter storm damage and its consequences constitute an ancillary benefit in the WMP, since it is not included as a risk mitigation target in any existing planning standard that guides WMP plan approval or scope of work approval at the OEIS and CPUC, respectively.

GPI generally supports asset and resource value stacking to support integrated planning, animate ancillary benefits, and to maximize asset cost-benefits. However, the OEIS and CPUC have not identified mitigating winter storm damage to overhead lines as an ancillary objective of the WMP. Nor has PG&E referenced or invoked any other open proceeding or OEIS Case that justifies higher cost asset investments in the WMP based on winter storm risk. Therefore. it is currently out of scope for the WMP and PG&E should not be permitted as a basis for mitigation selection. Investment selection based on winter storm damage must first be transparently and adequately justified (i.e. through supporting quantitative assessments) and subsequently approved by the regulatory agency (i.e. OEIS or CPUC) as a qualifying basis for higher-cost investments.[48]

At present, winter storm risk events are not consistently included in PG&E's Distribution Event Probability Models (DEPM) or WFC v4 model, which both predominantly intake wildfire season data (June-November).[49] Technosylva worst weather day simulations input into the WFC may include winter storm events—the event selection criteria are not reported in the WMP. The WDRM risk model output does not reflect winter storm damage likelihood or consequence and therefore cannot inform where high cost undergrouding would mitigate winter storm damage risk and increase the CBR of the investment.

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[48] For example, see BioRAM. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-procurement-programs/rps-bioram .

[49] PG&E's DEPM update plans include "Extending the event probability model time horizon beyond the wildfire season to cover the entire calendar year in support of public safety and reliability risk models." GPI recommends intervening in this proposed upgrade to ensure that wildfire risk models primarily identify wildfire risk and wildfire related reliability risk and not general asset damage and reliability risk, as this is out of scope for the WMP.

PG&E includes snow/ice damage as an outage failure mode in its Wildfire Benefit Cost Analysis (WBCA) tool used to calculate mitigation effectiveness.[50] The WBCA is touted as a historical review, and the "purpose of the historical calculation is to analyze all known potential failure combinations whether or not they caused an ignition."[51] The WBCA determines mitigation effectiveness based on reliability impacts **not** wildfire risk or risk related reliability impacts, since it is devoid of ignition event data. The example WBCA outage combination for "ice and snow" identifies the effectiveness of OH CC+EPSS as "none." This will lower the effectiveness score of a distribution overhead system based on reliability risk that occurs outside the wildfire season and during conditions that PG&E has not linked to ignitions or high wildfire consequence. Snow/ice are not included in the ignition drivers in Table 6 of the QDR, nor is it identified in the list of risk and risk drivers to prioritize.[52]

Applying the WBCA to inform mitigation effectiveness based on reliability risk drivers that are not linked to wildfire risk or wildfire risk mitigations (i.e. PSPS and EPPS) is a direct breach of the WMP scope. At a minimum, PG&E should be ordered to remove Snow/ice and other causes of outages or failures in the WBCA that are metrics of reliability and that are not linked to wildfire risk or wildfire mitigation-caused reliability risk. PG&E should be ordered to eliminate winter storm caused outages on overhead lines as a mitigation effectiveness metric and as a justification for selecting undergrounding as a mitigation. PG&E should be required to provide an analysis showing that snow and ice caused outage events contribute substantive wildfire risk or that snow and ice caused outage events independently introduce ratepayer consequences that warrant altering undergrouding scope of work or location-specific deployment.

C. Reject PG&E's distribution system "undergrounding first" mitigation selection process and decision tree. Least-cost risk mitigation portfolio development should start with overhead mitigation packages as the initial mitigation default.

PG&E states (emphasis added):

> *Overhead system hardening combined with operational mitigations EPSS and PSPS has a high-risk reduction benefit that is roughly comparable to that of undergrounding without these*

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[50] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 188.
[51] Ibid, p. 189.
[52] Ibid, p. 21.

> *operational mitigations.* PG&E continues to prefer undergrounding on high-risk circuits where feasible for several reasons. Undergrounding is permanent risk reduction that does not have the negative reliability impacts from PSPS and EPSS. … Over time, undergrounding also has lower operations and maintenance expenses.[53]

This high-level mitigation selection framework fails to include several critical considerations. PSPS and EPSS outage events are increasingly localized and have declined in frequency, scope, and duration. Also, a portion of these outage impacts can and already are being mitigated by permanent battery installation (i.e. distributed energy resource, DER) and microgrid investments. When these facts are included the big picture changes: A mitigation selection process must be capable of identifying location-specific PSPS and EPSS *residual* risk. Undergrounding should be considered for locations where an overhead mitigation package would result in unacceptable residual reliability risk due to PSPS outage events and possibly EPSS events.

PG&E's note that undergrounding has lower operations and maintenance expenses suggests that O&M cost savings can be gleaned in the long run compared to overhead systems. However, Undergrounded lines, which will have a larger footprint compared to the existing overhead lines (~1.2x), still require O&M investments, such as asset inspections and maintenance, system monitoring, and vegetation management along right of ways. A complete lifetime cost assessment, including CapEx, RoE, and O&M costs for location-specific OH versus UG lines and total distribution system portfolio should be completed to determine whether O&M costs of proposed undergrounded work would result in total portfolio cost savings.[54] In the absence of an analysis, the claim that "undergrounding also has lower operations and maintenance expenses" should not be assumed to mean that the total portfolio cost or annual cost to ratepayers will be less.

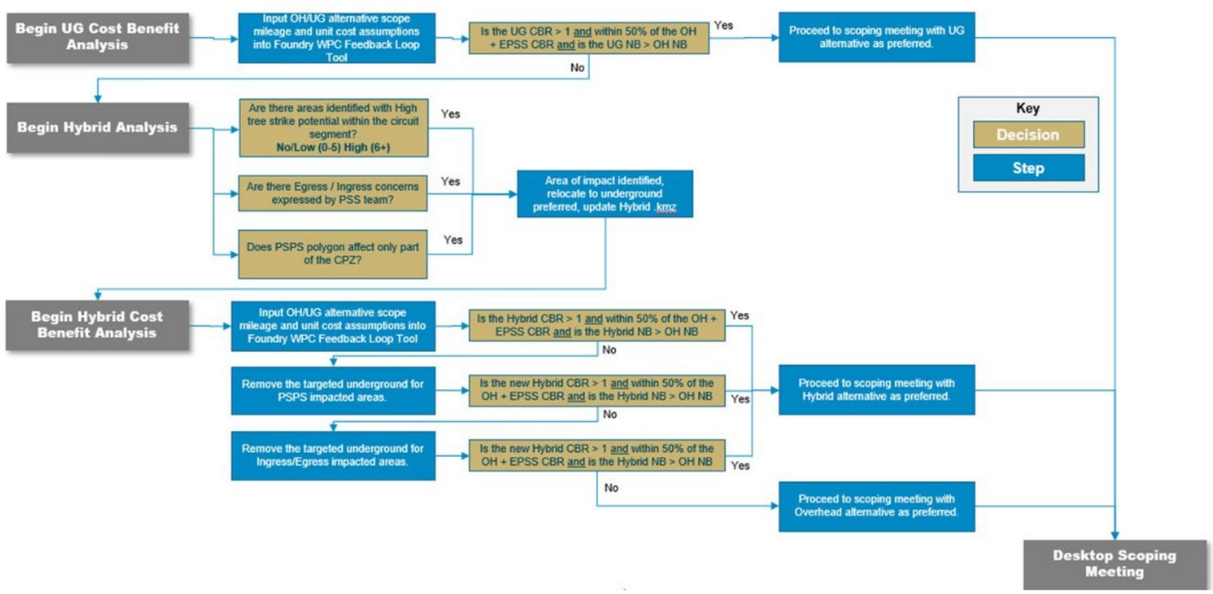
PG&E's initial underground scope in its 2026-2028 WMP appears to be based on "Geographic Area 1: Top Risk Areas based on Wildfire Risk Models (HFTD/HFRA)."[55] PG&E's long-term undergrouding scope may increase relative to prior WMPs since WFC v4 flattened and elevated

[53] Ibid, p. 134.
[54] Undergrounded CapEx + RoE + O&M costs must include the additional line mile conversion factor when replacing overhead systems (e.g. ~1.2 mi undergrounding per OH mi.).
[55] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, Table PG&E-6.1.3.2-1, p. 133.

the risk-ranked, risk buydown curve.[56] Risk ranked CPZs and the top n percent should no longer form the basis for grid hardening mitigation investment decisions. PG&E's granular risk scores must have actionable meaning regarding baseline and residual risk exposure at a given location, before and after an overhead mitigation package versus undergrouding is applied. PG&E should be ordered to propose more nuanced and transparent ignition risk driver and consequence exposure and residual risk thresholds to inform mitigation selection.

Figure 1. Reproduction from PG&E 2026-2028 WMP.

FIGURE PG&E-8.2.1-2:
PG&E'S SYSTEM HARDENING PROJECT SCOPING DECISION TREE AND PROCESS (2 OF 3)



PG&E's system hardening project scoping decision tree (2 of 3, Figure 1) further advances its Undergrouding-first paradigm. The process begins with an "UG Cost Benefit Analysis." While the first step suggests an alternative OH versus UG mitigation assessment, the Decision steps are designed to advance UG mitigations over lower-cost OH+EPSS. Seven decision steps are used to select UG versus OH hardening:

> UG CBA, Criteria 1 (UG CBR >1) implies that UG passes the first "screen" if the lifetime asset cost is even slightly greater than the cost of the risk it mitigates. For example, a $3.00M undergrounding project would pass this screen if it mitigated $3.01M of risk over the asset

[56] WFC v4 changes the risk buydown curve to 14,600 overhead line miles within the top 80% of HFTD/HFTD risk, versus 10,000 miles. See wildfire-consequence-model-documentation-v4.pdf, p. 1.

lifetime, allowing for UG selection based on a very small CBR margin. This is especially true considering the *average* CBR of CC and UG is 18 and 8, respectively, rendering a UG project with a CBR of ~1 well below the average CBR and therefore a below average location for value. Wildfire risk liability cost shift from utilities to ratepayers is more likely when an infrastructure mitigation cost benefit ratio (CBR) approaches or is less than 1. Considering asset lifetime, and O&M these UG infrastructure investments are more likely to cost ratepayers more than the estimated benefit.[57] A location-specific CBR of >>1 for infrastructure mitigations is more likely to result in a net benefit to ratepayers that outweighs the CapEx, plus utility return on equity and O&M costs.[58]

The risk reduction benefit portion of UG and OH hardening is based on the WDRM risk score, which is a relative risk score heavily impacted by consequence according to WFC v4 design. The risk reduction benefit is a proportional amount of the Enterprise MAVF Distribution Wildfire Score based on an Enterprise Risk to WDRM Risk calibration. The risk reduction benefit value is not an actual avoided cost. Since the WDRM is a relative risk model, a CBR of 1 does not necessarily mean that the investment cost equals the avoided risk cost. Criteria 1 sets a very narrow CBR margin and low bar that is based on relative consequence and less likely to yield ratepayer savings.

UG CBA, Criteria 2 ([UG CBR] within 50% of the OH+EPSS CBR) effectively approves any UG project that provides the same risk mitigation as OH+EPSS but at twice the cost. This does not balance safety, reliability, and affordability or conform to a least-cost best-fit approach.

“OH” distribution hardening includes CC+line removals with remote grids, but is dominated by CC.59 The OH+EPSS mitigation package (79% effective) does not include the complete available overhead distribution system mitigation package. We assume “EPSS” includes the updated DCD capability, though it is not clear.60 If it does not, DCD should be included in the OH mitigation packgae. Additional widespread deployment of other complimentary overhead mitigations, including but not limited to sectionalizing, exempt equipment replacements, as well as operations, maintenance, and situational awareness improvements contribute to the high wildfire risk reduction effectiveness of a modern distribution overhead risk mitigation package. Any CBR comparison between distribution undergrouding and overhead should be modified to include the entire available overhead distribution system package.

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[57] **California Public Utilities Commission (CPUC).** (2024). *Senate Bill 695 Report: Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1*. July 2024. p. 50.
[58] CBR=[NPV of Risk Reduction (in risk-adjusted $M)]/[NPV of Program Costs (in $M)].
[59] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 180.
[60] Ibid, p. 190.

Criteria 2 should be outright rejected on the basis that it does not automatically select the mitigation package that provides the highest CBR. PG&E should be ordered to adjust its screen to pass the mitigation that provides the highest CBR.

UG CBA, Criteria 3 (UG NB > OH NB) invokes net benefit, which we assume is the NPV of Risk Reduction – NPV of program costs. The NB calculation is missing from the WMP and PG&E should be required to provide it in a Revision Notice that includes a stakeholder review opportunity. Screen 3 essentially sets a very low risk tolerance threshold that approves undergrounding based on its ability to provide any margin of net benefit over OH+EPSS. This means, an undergrouding project that is twice the cost of OH+EPSS but offers even a < 1% margin of additional risk reduction will be preferred. This is not an appropriate risk tolerance or planning standard as it fails to balance ratepayer safety, reliability, and affordability. This criteria should be rejected and PG&E should be order to propose an alternative risk threshold for UG selection that directly relates to catastrophic wildfire risk exposure.

Hybrid Analysis: Any CPZ that does not pass Criteria 1-3 can still qualify for UG based on a "Yes" to any of the three following criteria:

- High tree strike potential (6+)
- PSS team expresses Egress/Ingress concerns (SME judgment)
- PSPS polygon affects part of the CPZ

This introduces subjective SME decision making that can reallocate any CPZ slated for OH mitigations to the UG scope of work.

The basis for egress/ingress "concerns" is not defined. Tree strike potential is already included in the p(i|o) model. Egress/ingress risk is included in the consequence score (WFC v4). Both already influence the Wildfire Risk score and CBR. These duplicated inputs override the risk model-based CBR with SME judgement.

The PSPS polygon criteria is presumably a binary Y/N option and does not clarify the data source. It does not appear to be based on the PSPS risk model output. Assuming this is based on actual PSPS event polygons (e.g. versus a 10-year backcast) we interpret this to mean that a CPZ would qualify for UG if a single PSPS event polygon overlapped part of the CPZ or impacted very few customers, including prior to updated PSPS event criteria and sectionalizing that has reduced PSPS frequency, scope, and duration.

All three of these "re-qualifying" criteria completely disassociate UG investments from CBR and permit extremely low and subjective risk tolerance thresholds for UG versus OH system hardening. Amusingly, the Decision flow does not offer an optional "No" path, indicating the only "right answer" is "Yes" UG. There is no other mitigation option pathway. At the bare minimum, PG&E should be ordered to clarify the risk tolerance thresholds and decision criteria and add a "No" decision tree path. We provide additional recommended improvements below.

Hybrid CBA: The re-added undergrouding CPZs are then passed through the same low-bar CBR and NB Criteria as in the UG CBA, but for a hybrid OH+UG scope. It's not clear at what resolution each CPZ is hybridized. For example, is UG added/removed in 1-mile segments or based on risk model resolution? Regardless, the Hybrid CBA sequence is built to retain as much UG scope as possible through incremental removals, while still passing its low-bar CBR and NB thresholds. UG scope is first removed based on PSPS impacted areas, which is an illogical risk-based decision since UG is the only mitigation that could eliminate PSPS event risk (if carefully sited).

Only after a CPZ starting with 100% UG scope fails all 7 decision steps is it scoped for OH system hardening. This method will result in a sprinkling of distribution system undergrounding across the HFTD along any circuit segment where it offers a small marginal risk reduction at up to twice the cost of an overhead system. As evidenced by PG&E's 10-year forecast, most risk through 2033 will continue to be managed by operational mitigations (EPSS + PSPS) despite large CapEx investments in undergrounding. There are no metrics that indicate PG&E is implementing a least-cost best-fit mitigation portfolio that reduces both wildfire risk and reliability risk at the most affordable cost. All customers will pay a high price for wildfire risk reduction in electric bills and some are likely to pay an additional "high price" in ongoing outage risk.

PG&E's 2026-2028 WMP should be rejected based on its system hardening project scoping decision tree and process for the following reasons:

- All criteria advance an undergrouding first paradigm which is not in accordance with regulatory goals to balance safety, reliably, and cost or least-cost, best-fit investment principles.
- Winter storm damage prevention as an ancillary benefit to UG is not in scope for the WMP, is not reflected in granular risk scores, is not adequately justified, and is not an agency approved or supported mitigation selection basis.
- PG&E's system hardening scoping method begins with assuming 100% UG, the highest cost mitigation approach that requires an overhaul of the existing overhead primary distribution system and parallel secondary lines and fails to leverage the plethora of existing overhead mitigation investments. Starting with the highest cost mitigation is not in accordance with balancing ratepayer safety, reliably, and cost or least-cost, best-fit investment principles. Achieving these goals generally requires a portfolio development process that (1) begins with the highest CBR and/or least-cost option, in this case 100% OH(system)+EPSS/DCD+PSPS, which includes improved and more efficient O&M methods as well as leverages existing assets with remaining usable life plus recent new investments (e.g. permanent batteries, non-exempt equipment replacement, repairs, pole replacements, etc.); and (2) subsequently adds or substitutes in higher cost mitigation

options (e.g. UG) (i) where the residual risk exceeds a transparent and defensible risk tolerance based planning standard that balances marginal risk reduction goals with affordability,[61] (ii) when the alternate mitigation CBR is greater than the least-cost option ($CBR_{UG} > CBR_{OH+EPSS+DCD+PSPS}$), and/or (iii) when ancillary benefits are sufficiently justified to warrant a higher cost investment with approval from a regulatory agency (e.g. BioRAM). PG&E's system hardening project scope decision tree and process fails to include these design tenets of balanced safe, reliable, and affordable, as well as least-cost best-fit investments.

- The system hardening selection method does not appear to consider granular PSPS Risk model outputs. Strategically sited undergrounding can eliminate PSPS event risk on the distribution system and DER can address PSPS consequence (i.e. overhead system). Sub-optimal UG placement can fail to protect interconnected customers if an upstream overhead line experiences a PSPS and there is no alternative energy source for customers within the downstream event polygon.[62] It's not clear that the system hardening project scoping decision tree is capable of siting most UG mitigations (location and scope) to also mitigate PSPS outage risk, which is now the primary risk mitigation capability that sets it apart from an overhead mitigation package. The PSPS mitigation effort is generally described as a case-by-case consideration in areas "frequently" impacted by PSPS events to determine if upstream undergrouding would "reduce" or eliminate local PSPS.[63] The standard used to determine what qualifies as sufficiently "frequent" and "reduced" risk to warrant additional undergrouding is not provided. It's unclear if this case-by-case assessment expands the UG scope of work beyond the decision tree outcomes of if the additional scope must also qualify under PG&Es CBR and NB Criteria. In general PG&E seems to rely on maximizing the UG footprint as a way to incidentally address some PSPS risk. Based on PG&Es own 10-year assessment, operational mitigations including PSPS will not be significantly mitigated and will still account for most of the wildfire risk reduction through 2033+.[64] PG&E should be required to develop a system hardening selection method that also reduces PSPS reliability risk and that is informed by residual risk and a reasonable and transparent risk tolerance threshold.

[61] Preferably set or approved by a regulatory agency in the future.

[62] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 168, 195

[63] Ibid, p. 195

[64] Ibid, p. 149

PG&E should be ordered to revise its system hardening project scoping decision tree to provide the recommendations detailed above. PG&E's system hardening project scoping Decision tree should advance a paradigm of balanced safe, reliable, and affordable service, as well as least-cost best-fit investments.

PG&E's planning standards "catastrophic wildfires shall stop" and "PSPS events as a mitigation of last resort" are not trackable planning standards or thresholds that can be readily associated with risk model outputs and/or risk drivers to justify higher cost mitigations in exchange for any marginal NB. For example, PG&E's risk tolerance for "PSPS events as a mitigation of last resort" is system design specific and could result in the same customers experiencing 1-in-50 year or 1-in-2 year "last resort" PSPS event frequencies depending on location-specific system hardening design. Put another way, how often PSPS events are enacted as a "last resort" depends on the system design. PG&E should be ordered to provide transparent and measurable risk tolerance thresholds for both wildfire risk and PSPS risk that directly relate to its risk model outputs and that inform its system hardening project scoping decision tree. An example of a transparent risk-based planning standard is to build a system that mitigates the likelihood of experiencing 5 or more PSPS events in 10 years based on a 20-year backcast.

The WMP must include a project scoping process that leads with maximum CBR and/or least-cost options and adequately justifies departure from those options in favor of lower CBR or higher cost mitigations on the basis of transparent marginal risk reduction gains or the achievement of a risk-based planning standard. The project scoping process must also be capable of informing granular system hardening investments that identify and mitigate both wildfire and reliability risk. This is essential for evaluating the reasonableness of the proposed scope of work in the GRC, which will ultimately determine whether PG&E's system hardening portfolio is approved, modified, or denied. The PG&E's project scoping process does not satisfy these design elements and therefore should be denied and revised.

D. PSPS events should be included as part of an Overhead mitigation package in the CBR analysis.

PG&E's WMP states:

> This analysis shows that operating under 2021 PSPS guidance could have prevented 100 percent of historical catastrophic and destructive fires. Since the 2021 guidance is calibrated using historical fires, we have reduced the effectiveness to 95 percent based on SME judgment.[65]

And

> PG&E estimates PSPS is 95 percent effective at reducing catastrophic wildfire risk and, for this reason, considers PSPS to be a cornerstone of PG&E's operational mitigations.[66]

And

> PG&E implements PSPS events as a mitigation of last resort to reduce the potential for catastrophic wildfires during extreme weather events that could lead to wildfire.[67]

And

> We rely on our operational mitigations as interim mitigations to reduce system risk until more permanent, long-term System Resilience mitigations can be fully deployed….The operational mitigations we deploy include (1) PSPS…(2)EPSS.[68]

And

> … undergrounding does not always eliminate PSPS risk for the directly-connected customers, especially when the undergrounded line remains connected to an overhead line (either upstream or downstream) in an area subject to PSPS events.[69]

And

> If overhead and underground lines are interconnected within the severe weather polygon, then the underground lines may still need to be de-energized during the PSPS event because they may not be able to be sectionalized from the overhead lines. Therefore, when evaluating which circuit segments should be considered for undergrounding, PG&E considers the relationship between overhead lines, underground circuit segments, and sectionalizing devices….This activity is expected to improve overall reliability. PG&E is working to quantify exactly how much reliability has improved where we have existing covered conductor and undergrounded segments.[70]

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[65] Ibid, p. 154.
[66] Ibid, p. 167.
[67] Ibid, p. 135.
[68] Ibid, p. 165.
[69] Ibid, p. 167.
[70] Ibid, p. 196.

Taken together this messaging is at odds with itself, referring to PSPS as a cornerstone mitigation, operational mitigation, mitigation of last resort, interim mitigation, and what amounts to a long-term risk reduction mitigation. PG&E's 2023-2022 Forecast of projected overall utility risk shows that operational mitigations (i.e. PSPS and EPSS) will account for the majority of wildfire risk reductions and will effectively serve as a long-term—not interim—mitigation despite proposed substantive investments in undergrounding.[71] The Covered Conductor and Undergrounding Risk Reduction Trend Analysis reports a 2 percent Cumulative % PSPS Risk Reduction from 2023-2024 undergrouding. The reported criteria for considering PSPS mitigation in system hardening decision making is vague at best. This suggests that PG&E's undergrouding first deployment method may not have a substantive PSPS reduction impact, equating to a high-cost mitigation approach with persistent wildfire risk-driven reliability issues.

The premium cost of undergrouding is most cost effective when it is selected based on mitigating high residual risk that cannot be mitigating by an OH system mitigation package. At this maturation stage PG&E reports that the primary difference between the risk reduction capabilities of a comprehensive overhead system hardening package and undergrouding is reducing PSPS risk.[72] This alters the cost-benefit value of undergrounding from a tool focused predominantly on reducing wildfire risk to a tool that is best suited for locations with high residual PSPS reliability risk after accounting for risk reductions from an OH system hardening package. That is, in these locations a hardened OH system would still require frequent PSPS events. Undergrouding locations should therefore be considered for their ability to reduce PSPS reliability risk as well as co-occurring wildfire risk.

PG&E's system hardening decision tree should consider quantitative baseline and residual, granular PSPS risk for UG versus OH-package mitigation selections. An Overhead system hardening package will always innately include PSPS as a mitigation component and therefore PSPS should be included and direct accounted for as part of the overhead mitigation package in the system hardening selection process and CBR. Targeted undergrounding can reduce PSPS risk, though the marginal reliability risk reduction benefit (i.e. relative to an OH mitigation

[71] Ibid, p. 149.
[72] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 165.

package) depends on location and scope. To our knowledge the CBR of UG and OH+EPSS in the decision tree do not include PSPS consequence risk model outputs and only considers co-occurrence with PSPS polygons.[73] PG&E did provide a waterfall analysis exhibiting the impacts of PSPS and EPSS mitigations on wildfire risk and reliability risk.[74] However, the analysis did not include the effects of a system hardening mitigation portfolio. This same type of analysis should be conducted on a granular scale and should include system hardening mitigations to inform locations where (1) UG mitigations effectively reduce PSPS risk plus wildfire risk and (2) where OH mitigation packages will substantially reduce wildfire risk without preserving high PSPS risk.

E. Utilities should be required to present multiple alternative system-level mitigation portfolios.

PG&E provides a waterfall analysis exhibiting the impacts of PSPS and EPSS mitigations on wildfire risk and reliability risk.[75] This analysis is akin to a system-level mitigation portfolio comprised only of operational mitigations. PG&E also provides 10-year projected overall service territory risk assessment, but the assessment does not differentiate between residual wildfire, PSPS, and EPSS risk. Neither assessment provides the wildfire and reliability risk reduction results or associated costs of *alternative* mitigations and resulting system portfolios. The final granular and total cost-benefit of PG&E's OH versus UG selections based on its project scoping decision tree is effectively masked behind seven decision criteria and does not offer comparison to alternative portfolios (e.g. a least-cost overhead option).

The same service territory waterfall and 10-year risk analyses should be conducted for multiple complete system-level mitigation portfolios that include system hardening plus operating mitigations. Granular system hardening mitigations should be aggregated to create the system-level mitigation portfolio. The portfolio results should include quantified residual PSPS and EPSS consequences, residual wildfire risk, and total cost.

[73] Ibid, p. 214.
[74] Ibid, p. 136.
[75] Ibid, p. 136.

At least two, and preferably three, alternative mitigation portfolios should be developed to directly compare the resulting residual reliability risk, wildfire risk, and total cost: (1) A portfolio based on PG&E's proposed system hardening decision tree; (2) A portfolio that assumes 100% HFTD coverage by a comprehensive overhead system hardening package; and (3) A portfolio based on an overhead system hardening package first paradigm, with UG substitutions in locations where $CBR_{UG} > CBR_{OH}$, or where residual PSPS risk or residual wildfire risk exceeds a transparent and justifiable planning standard. The portfolio-based residual risk assessment and total cost is necessary to inform how well the portfolio balances safety, reliability, and affordability objectives, including compared to alternative mitigation portfolios. This method is used in the IRP planning process as a tool to evaluate alternative mitigation portfolios that achieve risk-based planning standards with various cost-benefit tradeoffs.

IV. PSPS (Section 7)

A. The PSPS and EPSS risk reduction of already deployed and additional achievable DER deployment should be reported in the WMP.

PSPS and EPSS reported outage hours and modeled consequence scores are based on a combination of factors including but not limited to event footprint, grid assets, estimated outage duration, and customer outage impacts for vulnerable populations and critical facilities. These consequences are not net of existing DER and microgrid investments. Stand alone or hybrid (i.e. PV coupled) permanent BTM or IFOM battery systems can and already do provide ride through power for structures that experience power loss due to EPSS and PSPS outage events (see comments V.B). Both temporary and permanent microgrids are also mitigating PSPS and EPSS consequences for critical facilities and other customers, such as the temporary microgrid currently in operation at Calistoga Substation and its permanent in-development replacement. Similarly, PG&E's 11 operational and 20 additional in development remote grids have also likely mitigated PSPS and EPSS consequences that may still be included in PSPS and EPSS outage data.[76] PG&E and other utilities should be ordered to report on PSPS and EPSS reported outage hours and modeled consequence scores net of existing and planned DER deployments. Net

[76] WMP p. 6.

PSPS and EPSS consequences are necessary to inform existing risk mitigation investments, residual risk, and marginal reliability risk CBR associated with granular undergrouding versus overhead system mitigation package selections.

V. Grid Design, Operations and Maintenance (Section 8)

A. Overhead system risk mitigations and their risk mitigation value must be considered as packages, not individually.

Utilities, including PG&E, are faced with the fact that even if high-cost undergrounding plans are approved, overhead distribution infrastructure will remain a prevalent and perhaps the dominant distribution system type throughout the HFTD. PG&E and others have made, and continue to make, significant progress towards developing a robust overhead distribution system design, management, and operational mitigation package. This overhead system package functions synergistically, such that the individual parts work together to substantially reduce wildfire and reliability risk compared to each individual component and compared to earlier design paradigms. Evidence for the impacts of incremental overhead distribution system improvements over the past 7 years includes an improved understanding of its risk reduction effectiveness as well as reliability impacts associated with EPSS and PSPS.[e.g.77,78] PG&E reports that their overhead mitigation system is essentially as effective as undergrouding for mitigating wildfire risk but incurs PSPS risk. The overhead risk mitigation package includes already expended and planned ratepayer investments for updated and new hardware (e.g. covered conductor, non-exempt equipment replacements, sectionalizers, proactive transformer replacements, EPSS+DCD devices and enablement, REFCL, real-time grid sensors, microgrids, permanent BTM batteries, etc.) as well as the resolution of open and past due tags – and ongoing improvements are in the works.

System hardening mitigation packages should include the full suite of proactive mitigation types: elimination, substitution, engineering controls, and administrative or operational controls. Line

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[77] Joint IOU Grid Hardening Working Group Report: Update for 2026-2028 Wildfire Mitigation Plan. March 19, 2025.
[78] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 328.

removal is the only true elimination mitigation, which provides 100 percent wildfire and reliability risk reduction effectiveness while also precluding the need for O&M.

Undergrounding (UG) the distribution system constitutes a comprehensive infrastructure design change that mitigates wildfire and at least some reliability risk at all times of the year, regardless of risk severity (e.g. including on FPI <R3 days). The Undergrounding risk mitigation package should be considered a system substitution—charged lines and other electrical equipment is moved underground or pad mounted, not eliminated. It addresses risk associated with factors such as overhead conductor exposure, pole integrity, pole mounted equipment that is relocated to pad mounts, and vegetation proximity. Undergrounding systems will continue to require risk mitigation engineering controls (e.g. switches for isolating outage impacts) and administrative/operating controls including vegetation inspection and management (e.g. wrong tree, wrong place near pad mounted equipment, ROW clearance), equipment inspection and repair, and system health monitoring methods to inform proactive asset replacement.

PG&E reports a 98 and 99 percent average mitigation effectiveness for Undergrounding primary plus parallel secondary and service distribution lines versus all lines, respectively. We note that a one percent marginal risk reduction gain from additionally undergrounding all secondary and service lines suggests a low marginal cost-benefit ratio. Regardless, comparing the wildfire and reliability risk mitigation of undergrounding with Covered Conductor (CC) reconductoring or CC + EPSS is a misleading and false equivalency. The risk mitigation effectiveness of Undergrounding must be compared to a complete overhead system mitigation package.

The overhead system wildfire and reliability risk mitigation package reduces risk through a combination of permanent risk reduction elements (e.g. CC, expulsion fuse replacements), engineering controls (e.g. sectionalizing) and temporally and spatially targeted operational controls (e.g. EPSS and PSPS enablement). The comprehensive overhead system risk mitigation package includes many existing, planned, and/or available overhead risk mitigation controls, such as, but not limited to:[79]

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[79] Overhead mitigations may qualify under multiple control classifications.

- Hardware substitutions: Covered conductor, expulsion fuse replacements, exempt surge arrestors, pole replacements, system automation equipment (e.g. remote switches), and service breakaway connectors. Plus, system upgrades that address distribution system grid needs associated with increasing load (e.g. capacity, thermal, voltage), linked to the portion of ignition risk caused by electrical equipment overloading.e.g.[80]
- Engineering controls: Sectionalizing, REFCL, pole mounted sensors, EPSS + DCD devices and settings, smart inverters, ADMS devices, DER systems (hybrid PV and stand-alone Li-Ion battery systems), and microgrids.
- Administrative and operational controls: Risk informed vegetation management inspections and standards, asset inspection programs and protocols, timely asset repairs, proactive asset replacement (e.g. IONA pilot), situational awareness and forecasting tools (e.g. weather, grid health monitoring), EPSS enablement thresholds, PSPS thresholds, and grid modernization investments.

Even if PG&E is permitted to underground 8,000 miles of overhead lines, an overhead mitigation package will necessarily be implemented on the remaining 16,800+ circuit miles in the HFTD/HFRA. Meaning, the distribution overhead risk mitigation package must be robust and will be the subject of ongoing improvements, even with its wildfire risk mitigation effectiveness already rivaling that of undergrounding.

A level setting, apples-to-apples wildfire and reliability risk mitigation comparison to undergrounding must therefore consider the comprehensive overhead system mitigation package. PG&E's 2026-2028 WMP superficially addresses this issue with improvements in their reporting on combined overhead mitigation average effectiveness.[81] They report a blended average effectiveness for Covered Conductor (67%), CC + EPSS + DCD (79%), and CC + EPSS + PSPS (97%).[82]

DCD is inconsistently included, and it is therefore not entirely clear if or when DCD is included as part of EPSS or OH mitigation packages. Based on the WMP record and 2025 Joint IOU Grid Hardening Working Group Report, we assume EPSS consistently includes DCD. However, if it does not, all OH mitigation packages should include DCD. PG&E reported that as of 2024 DCD

[80] Ibid, p. 286.
[81] Ibid, p. 128.
[82] Ibid, p. 128, 190.

enablement and supporting installations now cover 87 percent of the HFTD/HFRA, which compliment ignition risk gaps in EPSS protective device settings.[83] CC+EPSS+DCD seems to offer improved ignition risk mitigation during non-PSPS conditions compared to earlier EPSS-only capabilities.

The limited overhead risk mitigation combinations fail to include the full suite of available and, in many locations, already installed substitution, engineering, and administrative or operating controls listed above. Already completed expulsion fuse, non-exempt surge arrestors, and pole replacements have reduced wildfire risk from known ignition risk drivers across the HFTD/HFRA. EPSS and DCD protective devices, additional installations, and enablement combined with sectionalizing investments, improved spatial fault detection capabilities. Updated operational mitigation protocols address ignition risk while also reducing the frequency, scale, and duration of wildfire risk reducing EPSS and PSPS outage events. In progress deployment of Advanced Distribution Management Systems, presented in the CPUC's HDER Proceeding (R.21-06-017), was reported as improving the "efficiency of EPSS and PSPS event execution."[84] Distributed energy resources (DER) and microgrids are already mitigating the reliability impacts of EPSS and PSPS outages.

Improvements in, and active work on, smart inverter enablement for effective DER deployment during abnormal grid conditions will further unlock reliability risk mitigation applications and value-creation.[85] REFCL remains a promising and complimentary overhead system wildfire risk mitigation despite PG&E's stalled pilot. PG&E's growing real-time grid monitoring capabilities, including Early Fault Detection, pole mounted sensors (Gridscope), and SmartMeters, contribute to proactive overhead system monitoring and rapid response for a wide range of ignition drivers.[e.g. 86] Timely solutions, such as DER-generation, demand response, and distribution system capacity expansion and upgrades in HFTD/HFRA locations identified as having grid needs via the distribution planning process can mitigate outage and ignition risk linked to an

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83 Ibid, pp. 326-327.
84 PG&E's 2027 GRC Grid Modernization Workshop. Presented March 13, 2025 in Proceeding R.21-06-017. Slide 26.
85 California Public Utilities Commission. *Smart Inverter Operationalization Working Group Report*. February 1, 2024. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K683/532683550.PDF.
86 GridScope. Fault Prevention. https://www.gridware.io/applications/fault-prevention.

overloaded system. Improved asset and vegetation management inspections, novel inspections approaches (e.g. LiDAR, Aerial-drone, IONA), inspection review processes (e.g. AI-enabled), substantially improved pass rates, and timely tag remediation also has a risk reduction benefit compared to past methods. Going forward, overhead system risk mitigation packages must include the full suite of completed and currently available complimentary risk management controls for a given location.

IOU work to date measuring the effectiveness of individual pilots, enhanced vegetation management practices, covered conductor, EPSS, and limited combinations of these mitigations is to be commended. As the comprehensive overhead mitigation package evolves, additional and ongoing work is warranted for studying overhead *system effectiveness* beyond isolated components. The comprehensive package of overhead system modifications for wildfire and reliability risk management must be considered when comparing with an alternative undergrounding option, which requires a complete system overhaul. GPI recommends requiring the IOUs jointly, including PG&E, to continue assessing holistic overhead system risk mitigation package effectiveness and to implement risk mitigation selection based on the most current, comprehensive overhead system risk mitigation package.

Scope of work approval should also take into consideration the amount of incremental overhead hardening investments already completed and whether the proposed mitigation portfolio maximally leverages existing CapEx investments. PG&E's undergrouding-first paradigm is likely to supplant incremental overhead mitigation work already completed (e.g. asset replacements).

B. Distributed Energy Resource (DER) installations and microgrids should be formally recognized as tools for Grid Design, Operations, and Maintenance. They should be included as a component in the overhead system risk mitigation package and a corresponding risk mitigation Cost-Benefit Ratio (CBR) should be developed.

We commend PG&E for reducing the Customer Average Interruption Duration Index (CAIDI) of EPSS outage events in 2024 to an average of 150 minutes[87] – at this outage duration, permanent residential battery systems can easily provide whole-house, outage ride-through services.

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[87] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 328.

PG&E reports having already installed 1,890 permanent batteries at AFN customer residences through its Residential Storage Initiative (RSI). This program is referred to as a limited time offer while supplies last.[88] The installed systems range from 10-13 kWh and are valued at $10,000. Average daily consumption for a California household in 2019 was 17 kWh.[89,90] Installations can power a whole-structure or critical circuits, altering outage ride-through duration depending on energy usage. RSI program batteries could be upsized to power a range of residences and businesses at the whole structure or critical circuit level, offering ride-through capabilities for longer duration outages such as PSPS events, in addition to EPSS events.

The RSI website also references existing related programs and associated cost benefits through the Self Generation Incentive Program (SGIP), which offers financial rebates for residential and small business battery installations. [91] The SGIP was developed in the Ratemaking Proceeding on California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues (R.12-11-005). The SGIP program and 2025 disbursement specifically reserves 50% of the small residential budget for those located in Tier 2 and Tier 3 HFTD, or have experienced 2 PSPS events, or have experienced one PSPS and 1 outage event from a wildfire, or have experienced more than 5 EPSS outages since 2023.[92] Non-residential customers that are critical facilities and meet these same criteria are also eligible.[93] PG&E's SGIP website indicates full cost coverage incentives for residences and businesses that are located in Tier 2 and Tier 3 HFTD, or have experienced 2 PSPS events, or have experienced more than 5 EPSS outages since 2023, plus have qualifying needs.[94] The SGIP program:

[88] PGE Residential Storage Initiative. https://www.pge.com/en/outages-and-safety/outage-preparedness-and-support/general-outage-resources/residential-storage-initiative.html.
[89] Based on an average annual consumption of 6,174 KWh in 2019.
[90] CEC 2019 California Residential Appliance Saturation Study (RASS). July 2021. https://www.energy.ca.gov/sites/default/files/2021-08/CEC-200-2021-005-ES.pdf.
[91] PGE Self-Generation Inventive Program. https://www.pge.com/en/save-energy-and-money/rebates-and-incentives/self-generation-incentive-program.html.
[92] California Public Utilities Commission. *Self-Generation Incentive Program Handbook, Version 1*. January 2025. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/2025-sgip-handbook-v1.pdf.
[93] Ibid, pp. 25-28.
[94] PGE Self-Generation Inventive Program. https://www.pge.com/en/save-energy-and-money/rebates-and-incentives/self-generation-incentive-program.html.

> … provides financial incentives for the installation of new qualifying technologies that are installed to meet all or a portion of the electric energy needs of a facility.
>
> The purpose of the SGIP is to contribute to Greenhouse Gas (GHG) emission reductions, demand reductions and reduced customer electricity purchases, resulting in the electric system reliability through improved transmission and distribution system utilization; as well as market transformation for distributed energy resource (DER) technologies.[95]

PG&E's RSI program correctly notes that these systems will serve reliability purposes for any outage, and "should provide enough power for the duration of most outages that occur in your area."[96] However, the SGIP purpose statement better reflects the wide range of benefits that DER can provide in addition to EPSS and PSPS reliability risk mitigation. This ongoing behind the meter energy storage procurement program is one example of an active integrated system planning effort that directly addresses EPSS and PSPS reliability impacts and is a source of revenue for DER storage solutions as one part of overhead system risk mitigation packages.

In July 2023, PG&E reported 6,557 total SGIP interconnection customers in the HFTD, and 12,138 total SGIP interconnected customers on EPSS circuits, with addition 2023 Equity Resiliency interconnection targets.[97] PG&E's remaining SGIP Available Funds for Equity Resiliency pools is $12.7M, which will support customers in the HFTD who have experienced EPSS and PSPS outages,. A back of the envelop calculation, based on the estimated SGPI $10k per unit cost, would equate to upwards of 1,270 additional 10-13 kWh Li-ion DER installations through remaining SGIP Equity Resiliency funds alone.[98] It is possible that some customers within the HFTD with EPSS and PSPS reliably risk could qualify for SGIP funds through other budget categories based on other qualifying factors (e.g. DAC residences or low-income).[99]

PG&E cites multiple similar *permanent* battery and generation backup programs to mitigate reliability risk associated with EPSS and PSPS outage events, including Fixed-Power Solutions

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[95] SGIP Program announcement and data. https://www.selfgenca.com/home/about/.
[96] Ibid.
[97] Pacific Gas and Electric Company CALIFORNIA PUBLIC UTILITIES COMMISION SAFETY BRIEFING, July 2023. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/pge_cpuc-safety-briefing_070623v2.pdf.
[98] SGPI Program Metrics. https://www.selfgenca.com/home/program_metrics/.
[99] E.g. the Costal range north of Santa Rosa, Northern Sierra Nevada Mountains, Lassen and Susanville regions. See DACs https://gis.water.ca.gov/app/dacs/.

(FPS), Permanent Battery Storage Rebate Program, Generator and Battery Rebate Program, Backup Power Transfer Meter (BPTM), the Self-Generation Incentive Program (SGIP), and the RSI program. Additional portable distributed battery and generation programs and saturation levels may indicate customer interest in permanent DER solutions. Based on available metrics outside the WMP and within the WMP, PG&E has made more substantial long-term mitigation progress on EPSS and PSPS reliability impacts than they are reporting in the RSI program alone. Conspicuously absent, however, are quantitative metrics on these existing programs and the total permanent DER penetration in the HFTD already mitigating EPSS and PSPS reliability risk.

The 2026-2028 WMP references these permanent DER programs only once, offering short 1-2 sentence summaries in Section 11.5 Emergency Preparedness, Collaboration, and Community Outreach: Customer Support in Wildfire and PSPS Emergencies. Including all DER deployment programs in Section 11, where there are no quantitative target reporting requirements, is unacceptable. Permanent DER installations, whether by third party owners, customers, or PG&E, are long-term equipment investments that qualify as a substitution and/or engineering control in risk mitigation. EPSS and PSPS reliability risk is a modeling and mitigation requirement and reducing this risk is a goal of the WMP and system hardening. Any permanent DER energy storage installation in the HFTD is a long-term substitution (i.e. energy source) and/or engineering control solution to granular EPSS and PSPS risk. DER reporting in the WMP should move to Section 8, Grid Hardening, Design, and Operations.

CBRs can and should be derived for permanent DER. Permanent battery installation CBR is likely a function of the EPSS and PSPS outage frequency, event duration, customer type served, and possibly other grid needs served by the battery during normal or abnormal grid operating conditions (i.e. value stacking) which would contribute to the total benefit of the installation (or modify the proportional cost allocated to WMP applications).[100] Permanent battery installations in locations that frequently experience PSPS or EPSS events, or above average duration events will increase the granular CBR relative to other locations. PG&E's permanent battery installation programs (e.g. RSI, SGIP, etc.) that target EPSS and PSPS affected "Extreme",

[100] DER value stacking is a subject of CPUC policy that warrants further exploration for the purpose of WMP considerations.

"Significant," and "Elevated" Critical Customer Types also have an elevated impact on EPSS and PSPS risk reduction.[101] The Extreme risk customer type has a customer weighting of 100:1 (e.g. hospitals, fire and police stations), while Significant (e.g. Life support, Medical baseline & Low income) and Elevated (e.g. Medical Baseline, Low-income) type customers have weightings of 5:1 and 2:1. Permanent home battery systems installed at these higher risk weighted customer locations will have a larger risk reduction outcome compared to DER installations for Regular Customers. The IOUs should be required to develop a total and granular EPSS and PSPS risk reduction CBR quantification method that includes DERs.

PG&E's Grid Modernization workshop also reported that work is in progress to expand the value of DERs already deployed for EPSS and PSPS mitigation applications to serve additional grid needs.[102] Value stacking, when a single investment serves multiple needs (e.g. functions as a Virtual Power Plant, provides services during abnormal grid operating conditions), considers the total cost benefit ratio of the investment. To properly value DERs, the value stacking analysis must include EPSS and PSPS benefits, which are not yet quantified in PG&E's WMP.

The SGIP has budget caps set through CPUC Ratemaking proceedings. However, PG&E fails to provide a justification for deploying the RSI program for a "limited time offer while supplies last." For all relevant programs including the RSI, PG&E should be required to report on (*i*) its permanent battery installation targets for each WMP year; (*ii*) the total battery deployment target for each program; (*iii*) all methods used to maximize CBR based on spatial EPSS and PSPS risk distributions and customer type within the HFTD, (*iv*) the total EPSS and PSPS risk reduction benefit of installed, in progress, and future RSI and other permanent batteries for each program; (v) the proportion of customer interest/demand met by all existing permanent and temporary battery programs in the HFTD; (*vi*) and the customer outreach methods used to deploy each program.

PG&E's own 10+ year forecast of wildfire mitigation risk reduction shows operational mitigations (i.e. EPSS and PSPS) as the primary driver of total managed risk even after

[101] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 69.
[102] PG&E Grid Modernization Plan Workshop, March 13, 2025, https://www.youtube.com/watch?v=4vVdlO6zOXA (2:52).

considering its costly undergrounding plans.[103] Permanent battery and generation backup programs are a critical design element in a comprehensive overhead system risk mitigation package, with or without undergrounding deployments. PG&E's own analysis suggests that permanent DER solutions to mitigate EPSS and PSPS outage risk will be an added cost to its proposed undergrouding-first system hardening plan, whether incurred by a customer, PG&E, or a third party.

Requirements to quantify permanent battery installation targets and CBR should be expedited to the extent possible. A primary challenge of the overhead risk mitigation package is the associated EPSS and PSPS reliability risk. Quantifying the reliably risk mitigation CBR of DERs necessitates timely action to (*i*) better inform overhead versus undergrounding mitigation selections, (*ii*) quantify the value-creation enabled by grid modernization work in progress through CPUC proceedings (e.g. R.21-06-017), and (*iii*) to contribute to DER value stacking assessments relevant to integrated distribution system planning. The above recommendations should be issued in an ACI with a reporting requirement no later than the 2027 WMP Update and should be considered in overhead versus undergrounding mitigation plan approval, modifications, or denials.

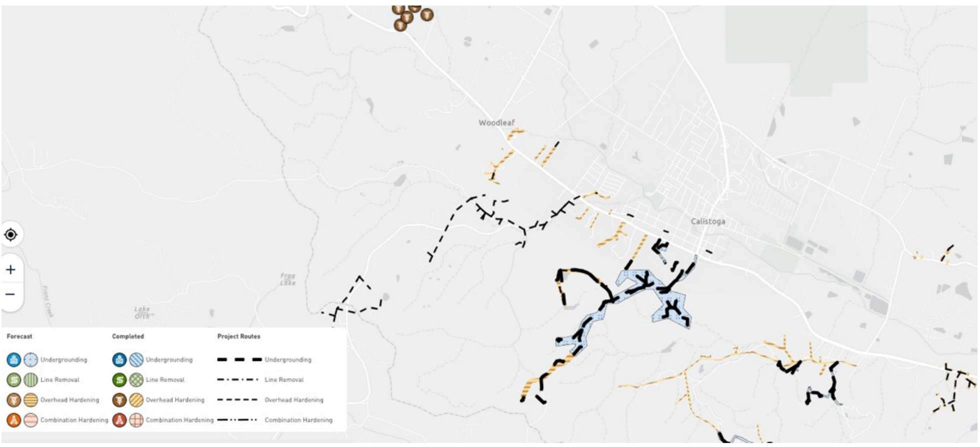
C. Undergrounding plans may delay PG&E's REFCL pilot and reduce its CBR.

Calistoga substation and its feeders (1101 and 1102) are a case study in integrated planning as it pertains to the confluence of wildfire mitigation and distribution system planning. On the wildfire mitigation front, PG&E has deployed REFCL, sectionizing, overhead hardening (CC + poles), EPSS enablement, and PSPS events. Planned risk mitigation investments include additional overhead system hardening and a patchwork of undergrounding that will be deployed along existing RECFL protected lines. This is also the site of PG&E's Calistoga Clean Substation Microgrid, which will supplant the temporary microgrid.[104] The Calistoga substation is also the site of identified grid needs in the distribution planning process and is slated for a new Bank and Feeder installation this year (2025) to address increasing capacity needs and peak loading exceeding 94 percent by 2028 ($8.2M). Existing and Queued distributed generation on

[103] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 149.
[104] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, P. 210.

the two existing feeders total 8.2 MW and 22.9 MW, respectively.[105] It is unclear whether the Queued distributed generation includes the Calistoga Clean Substation Microgrid or if the permanent microgrid triggered the distribution system upgrade. If the microgrid triggered the system upgrade, the cost of the distribution system upgrade is essentially a part of the granular ratepayer CapEx wildfire-reliability risk investment.

Figure 2. Calistoga substations and planned WMP system hardening mitigations.[106]



PG&E's only REFCL pilot is located at the Calistoga Substation and acts on its 160 primary distribution circuit miles. In their 2026-2028 WMP they report that the pilot "continues to progress but is still currently in the testing and evaluation stage." Staged fault testing in 2023 was successful. However, REFCL was only enabled 15 percent of the time in 2024. Although there have been no ignitions while REFCL was enabled, they report that the pilot has not generated sufficient data to calculate wildfire risk reduction effectiveness.[107]

Calistoga substation connected circuit segments that benefit the most from a REFCL installation and provide the data necessary to evaluate its effectiveness are likely the distal circuit segments within the HFTD Tier 3 zone and at the Calistoga urban area interface. PG&E plans to underground 15.2 miles of the Calistoga 1101 and 1102 feeders along a portion of the distal

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[105] PGE GRIP map. https://grip.pge.com/ Calistoga, CA, Data layers: Substations, Distribution; Distribution Lines; High Fire Threat District; DIDF, Load Forecast at substations (% overloaded); DIDF, Grid needs at substations (% overloaded); DIDF, Planned Investments. Accessed May 18, 2025.
[106] PG&E wildfire mitigation map. https://vizmap.ss.pge.com/.
[107] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 337.

circuit segments, resulting in a mosaic of undergrounded and overhead hardened distribution lines.[108,109] Implementing undergrounding on the REFCL-enabled pilot feeders essentially removes overhead lines from the 160 enabled line miles. Furthermore, it removes line miles that benefit relatively more from REFCL protection compared to, for example, circuit segments in the more urban environment of Calistoga, CA.

PG&E's plan results in a veritable Catch 22: the very act of undergrounding removes the line segments where REFCL would be most impactful and provide the highest risk reduction, thereby making it more difficult to timely measure REFCL's success or justify its future use as part of an overhead mitigation package in lieu of undergrounding. The reduction in the REFCL footprint along the circuit segments that can benefit from the existing overhead mitigation the most will reduce the data collection rate and further slow the effectiveness assessment. Supplanting existing overhead distribution system risk mitigation investments with high-cost undergrounding is not a complimentary mitigation build out approach. It nullifies the existing overhead mitigations and increases the granular risk reduction cost (i.e. the cost already invested in the overhead system protection plus the cost of the undergrounding). Undergrounding the circuit segments that benefits from the REFCL installation the most lowers the REFCL CBR and the total CBR (i.e. risk mitigation associated with undergrounding divided by the cost of existing overhead mitigations plus the cost of undergrounding). GPI is concerned that PG&E's undergrounding plan on Calistoga 1101 and 1102 feeder circuit segments will substantially slow the REFCL pilot effectiveness assessment and may even skew the REFCL CBR—stymying its roll out from pilot to widespread deployment as part of the overhead distribution system mitigation package.

Calistoga Substation is also identified as requiring a new bank and feeder to meet system capacity needs. If this distribution system project expands the overhead footprint within the HFTD Tier 3 and is enabled with REFCL at the Calistoga substation, this could increase the REFCL protection footprint in support of timely evaluating its effectiveness. However, despite requirements to report on integrated distribution system planning, the WMP makes no mention

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108 PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025. PGE_20262028_BaseWMP_Atch02_R0.xlsx, Table 4.3.
109 PG&E wildfire mitigation map. https://vizmap.ss.pge.com/

of any planned new distribution infrastructure within the HFTD or that intersect with existing/planned mitigations. It is therefore unclear whether the new Calistoga 1103 feeder will distribution footprint in the HFTD Tier 3, and if so how the new risk exposure will be mitigated, including whether it will connect to the REFCL system and contribute to the ongoing pilot.

Notably, Calistoga circuit segments do not appear to rank in PG&E's WDRM v4 Top 20 percent Risk Circuit Segments. Calistoga circuits 1101 and 1102 rank 34 and 35, respectively, as frequently deenergized circuits. However, PG&E has successfully decreased the number of customer PSPS outage hours on the Calistoga 1101 and 1102 circuits. Presumably this is due to sectionalizing investments and/or more discerning PSPS events and is not simply a function of weather.

Table 2. Total Customers PSPS Outage hours per year for Calistoga feeders 1101 and 1102. Data Source: 2026-2028 PG&E WMP Table 4.3.

	Total Customers PSPS Outage hours per year	
Year	**CALISTOGA 1101**	**CALISTOGA 1102**
2019	343,786	171,268
2020	220,782	104,347
2021	35,311	23,868
2023	71	0
2024	19,071	877
Average	123,804	75,090
[PG&E] Estimated Annual Decline in PSPS Events and PSPS Impact on Customers (Customer hours)	115,662	63,411

PG&E (1) substantially decreased wildfire risk on the Calistoga feeders with completed CC + REFCL + EPSS + PSPS (and perhaps other mitigations e.g. DCD); (2) will continue to reduce wildfire risk with additional planned overheard hardening (CC + pole repair/replacements); (3) has already mitigated a portion of the reliability risk (frequency, scope, and duration) associated with EPSS and PSPS outage events through sectionalizing and more targeted event enactment; (4) is mitigating a portion of the residual EPSS and PSPS customer reliability risk with a temporary microgrid that is soon to be converted to a permanent microgrid; (5) may be mitigating additional residual EPSS and PSPS customer reliability risk through its permanent battery programs; and (6) is addressing local distribution capacity constraints and possible overloading risk drivers through the distribution planning process that will unlock interconnection opportunities for 22+ MW of queued distributed generation likely capable of providing outage ride-through support.

Questions must be asked. How much residual wildfire and reliability risk remains on Calistoga substation circuits at present after deploying the existing distribution overhead mitigations? What is the amount of residual wildfire and reliability risk on Calistoga substation circuits if it is hardened with a complete overhead mitigation package and what is the CBR? What is the amount of residual wildfire and reliability risk that the proposed undergrounding work will eliminate and at what CBR and total cost?[110] What detriment does the proposed undergrounding project have on the ongoing REFCL pilot, relative to the marginal risk reduction benefit and CBR of the undergrounding project.

PG&E should be required to report on (*i*) how its undergrounding plans are likely to alter the REFCL pilot effectiveness analysis and CBR; (*ii*) an estimate of how much additional data and time is needed to quantity the effectiveness of the Calistoga REFCL pilot (at which point the marginal CBR of underground versus overhead system hardening on the Calistoga circuit segments can be better informed); (*iii*) justify its decision to cite undergrounding along rural circuit segments of their only REFCL pilot before the pilot provides meaningful results. The justification should include an assessment of the residual total circuit and circuit segment wildfire and EPSS + PSPS outage hour risk after all existing and near-term planned *overhead* mitigations are considered, including completed sectionalizing, existing and in progress microgrid services, permanent battery installations and improved EPSS and PSPS methods. The justification should also include the amount of the residual circuit segment risk that the proposed undergrounding projects will mitigate and the marginal CBR compared to a complete overhead mitigation package.

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[110] A Google earth satellite view of the planned undergrouding segment shows few structures.

The purpose is two-fold. It is prudent to ensure that the REFCL pilot and its effectiveness can be ascertained in a timely manner without skewing the CBR. Timely results from PG&E REFCL pilots are necessary to inform whether more widespread deployment of REFCL as part of the overhead distribution system mitigation package improves risk reduction and the CBR. It is also critical to assess not only granular baseline wildfire and reliability risk reduction, but also the remaining granular residual risk based on existing mitigations (i.e. all related ratepayer investments including at least a portion of DG, microgrids, and triggered infrastructure upgrade costs) and the amount of marginal risk reduction and CBR that results from deploying a complimentary overhead mitigation package versus supplanting existing overhead mitigations with undergrouding that substantially adds to existing location-specific mitigation costs. Calistoga feeders provide a useful case study to support cost-effective system hardening decisions.

D. Require all IOUs, including PG&E, to report on wildfire risk exposure associated with Advance Conductor deployments or deployment plans, and perform a joint assessment of Advanced Conductor failure modes, wildfire risk exposure, and conductor-specific inspection methods.

Advance Conductors (AC) have gained traction in recent years for their higher capacity, ability to withstand higher temperatures, and low sag properties compare to traditional Aluminum (Al) Conductor Steel Reinforced (ACSR) lines. Advanced conductors come in a range of designs such as metal matrix or carbon cores and Al or Al-Zirconium conductor strands. A primary difference is often the elimination of the legacy steel core, reducing weight and line sag at high temperatures, in exchange for more conductive Al strands.[e.g.111] The most touted attributes are their ability to increase existing transmission line capacity by reconductoring while also reducing line sag associated with wildfire risk (e.g. Transmission line slap, vegetation contact).[e.g.112]

Advanced conductors are of particular interest in California where growing energy demand and GWs of clean energy interconnection requests are anticipated to exceed transmission capacity in

[111] Electric Power Research Institute (EPRI). *Advanced Conductors.* Report No. 3002030547. Palo Alto, CA: EPRI, 2020. Available at: file:///Users/zoeharrold/Downloads/3002030547_Advanced%20Conductors%20(2).pdf/.
[112] CTC Global. *ACCC® Conductors Could Offer a Solution to PG&E Power Shutdowns*. Available at: https://ctcglobal.com/accc-conductors-could-offer-a-solution-to-pge-power-shutdowns (accessed May 21, 2025).

the coming years.[e.g.113] Advanced conductors may offer a solution to quickly increase transmission capacity and mitigate line losses along some existing transmission lines, while also reducing the land-use impacts and wildfire risk associated with transmission system footprint, and offering a bridging strategy for 10+year timelines to approve and install new transmission lines.

PG&E and SCE have sought funding to upgrade over 400 miles of steel core transmission lines with carbon fiber or composite core advanced conductors.[114] It is possible that reconductored transmissions lines with Advanced conductors will, or already do, cross HFTD regions. For example, many of PG&E's transmission lines cross through HFTD Tier 2 and Tier 3 regions (Figure 1), connecting high resource potential lands (e.g. desert and basins) to population centers.

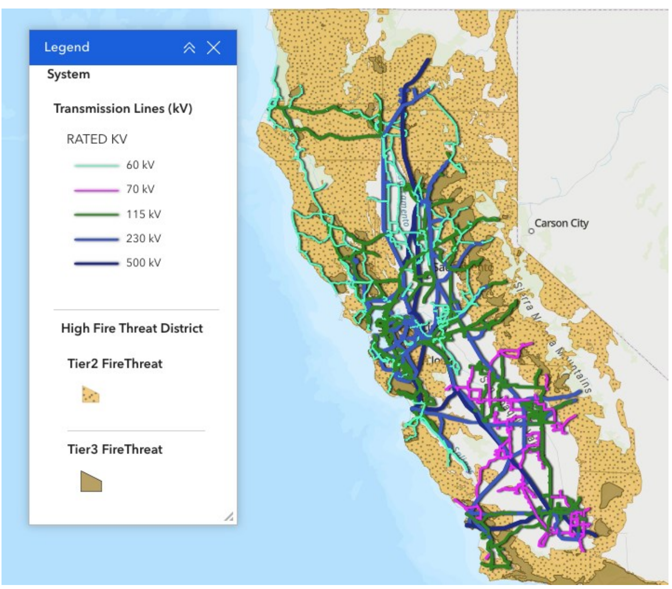

Figure 3. *HFTD Tier 2 and 3 zones overlain with PGE Transmission Lines showing potential scope of Advanced Conductor deployment in the HFTD. Source: PG&E Grid Resource Integration Portal, Accessed April 17, 2025.*[115]

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[113] U.S. Department of Energy. *California Energy Commission – Grid Resilience and Innovation Partnerships(GRIP) 2.0, 40103(b) Fact Sheet*. October 2024. Available at: https://www.energy.gov/sites/default/files/2024-10/CaliforniaEnergyCommission_GRIP%202_40103b_Fact_Sheet.pdf.

[114] Statewide Partnership Aims to Deliver More Clean Energy Faster to Californians and Support State Climate Goals, April 18 2024, https://investor.pgecorp.com/news-events/press-releases/press-release-details/2024/Statewide-Partnership-Aims-to-Deliver-More-Clean-Energy-Faster-to-Californians-and-Support-State-Climate-Goals/default.aspx Accessed 4/17/2025.

[115] PG&E Grid Resource Integration Portal. https://grip.pge.com/ Accessed April 17, 2025.

In support of PG&E and SCE's Advanced Conductor reconductoring efforts, it is important for the IOUs to proactively identify any novel transmission ignition risks, failure modes, and/or asset inspection methods relevant to wildfire mitigation and Advanced Conductors. For example, this may include novel or enhanced wildfire risk from higher line capacity, failure modes that vary relative to traditional steel core transmission conductors, lifespan metrics, and line inspections specific to composite and carbon fiber core advanced conductors. While an overall promising technology, advanced conductors, may present unique and yet to be identified ignition risk. The early stages of covered conductor deployment, which called for new inspection parameters and methods to manage CC specific failure modes (e.g. insulator wear and tear, vibrational damages, etc.), offer lessons learned for assessing transmission conductor risk management as it pertains to Advanced Conductors and updating utility methods as necessary towards successful HFTD reconductoring projects.

A June 2024 report by Electric Power Research Institute (EPRI) highlights relevant considerations for Advanced Conductors that may span the HFTD, stating:

> … most failures of advanced conductors have been attributed to improper installation. Further research on installation, as well as long-term performance (thermal degradation and mechanical—for example, ice loading), inspection, and assessment after a critical mass of conductors is deployed can de-risk investments…
>
> The long-term thermal and mechanical performance of these advanced conductors is not fully understood. As more of the advanced conductors are deployed, valuable service experience is being obtained. Key topics that must be better understood include vibration and the ice-loading performance of these conductors.
>
> As these conductors age in the field, the need for core inspection and condition assessment increases. Although several different technologies and methods for inspecting the core of steel conductors exist, it is difficult to determine the condition of nonsteel core advanced conductors.[116]

GPI is an advocate of reconductoring transmission lines with Advanced Conductors in support of zero-emission and renewable energy development, greenhouse gas emission reduction goals, and electrification trends. Towards achieving these benefits, we advocate for early utility

[116] Electric Power Research Institute (EPRI). Advanced Conductors. https://restservice.epri.com/publicdownload/000000003002030547/0/Product

engagement and transparency at the nexus of advanced conductor technology, transmission planning, and HFTD wildfire risk. Finding solutions and monitoring approaches for any known and yet to be determined wildfire risk factors before implementation will support timely deployment, risk mitigation, and critical early successes that pave the way for maximally leveraging this advancement in transmission line design, including in the HFTD.[e.g.117]

GPI recommends requiring PG&E and SCE to initiate a joint wildfire risk management assessment for Advanced Conductors that cross the HFTD, including but not limited to known failure modes, possible design standards (e.g. sensor installation for asst health monitoring), and updated or novel asset inspection methods.

In addition to asset health and failure modes, advanced conductors could pose unforeseen consequences to WMP outage risk. The primary allure of advanced conductors is their ability to increase line capacity along existing transmission right of ways, leveraging existing infrastructure. This same benefit also increases system reliance on individual transmission lines. For example, an outage on a fully utilized advanced conductor (e.g. 2,000 MW) could result in twice the electric capacity loss as the original conductor (e.g. 1000 MW). This could equate to larger reliability impacts during Transmission level PSPS or unplanned outage events, due to a single line serving more customers and/or higher customer load (e.g. transportation and building electrification). GPI recommends requiring that a joint wildfire risk management assessment for Advanced Conductors include estimations of WMP related outage risks as necessary.

Advanced Conductor deployment in distributions systems is feasible but relatively less well known compared to transmission system applications. GPI has connected with developers at CTC Global, whose ACCC product utilizes a carbon core encased in glass fiber. Insights from CTC Global developers indicated that ACCC paired with insulation coverings (e.g. CC) has limitations, suggesting more work is required to unlock advanced conductor applications in distribution systems within the HFTD/HFRA. To our knowledge, IOUs have not publicly

[117] D. H. Waters, J. Hoffman and M. Kumosa. (2019) Monitoring of Overhead Transmission Conductors Subjected to Static and Impact Loads Using Fiber Bragg Grating Sensors. IEEE Transactions on Instrumentation and Measurement, vol. 68, no. 2, pp. 595-605 https://ieeexplore.ieee.org/abstract/document/8472255.

considered AC deployment in distribution systems. We therefore focused our comments on AC deployment in transmission systems that transverse the HFTD/HFRA.

VI. Vegetation Management and Inspections (Section 9)

A. ACI PG&E-25U-08 – Reinspection of Trees in the Tree Removal Inventory.

ACI PG&E-25U-08 required PG&E to report on its tree re-inspection program planned for 2024. PG&E clarifies that it began planning the pilot in late 2024 and provides a high-level summary of the pilot scope. It states that actions will be identified once the pilot and resulting data analysis is completed.[118] GPI recommends issuing PG&E a revision notice that requires it to (*i*) provide a summary of work completed to date with an estimate of percent completion for core pilot stages (e.g. planning: 100% complete, inspections: 10% complete), (*ii*) a timeline for pilot completion, and (*iii*) a milestone target deadline (e.g. Q3 2026) for completing a pilot report that includes results and planned actions.

B. CI PG&E-23B-16 – Updating the Wood Management Procedure.

PG&E updated Vegetation Management Wood Management Program (Utility Standard TD-7116S) in response to ACI PG&E-23B-16.[119] This updated standard document provides stronger linkages to defensible space policies, expands wood management services to more customers than prior procedures, and implements a new response plan and schedule.

The updated response plan and schedule sets three response timelines: Safety Exceptions, Expedited Priority, and Routine Priority. This plan appears structured to improve the response to customer requests for wood management support and ideally will facilitate defensible space maintenance following utility VM activities. This is also an improvement over the prior procedures which lacked a scheduling framework. The WMP states that wood management activities typically happen within 90 days of VM work. The 90-day timeline is not included in the standard documentation and is therefore not an established target for determining what

[118] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 582.
[119] Pacific Gas & Electric. (2024). *Utility Standard TD-7116S: Vegetation Management Wood Management Program*. Rev. 1. Effective January 27, 2025.

constitutes timely wood management work. The updated wood management standard also expands its services from fire impacted customers to customers more broadly. Eligibility is outlined in the WMP as operating on a "case-by-case basis in response to customer requests on distribution VM programs."[120] This language is vague and does not clarify what PG&E considers as qualifying "cases" or whether and how customers are notified of available wood management services. As data and customer feedback accumulates over time, it remains prudent for OEIS and stakeholders to track whether and how TD-7116S (issued January 2025) impacts woody biomass build up on customer properties (especially within defensible space zones) and along distribution system right-of-ways.

Additional work is still required to assess the fuels build up rate due to utility vegetation management activities and wood management procedures in accordance with existing regulatory requirements. Extensive and aggressive VM work along utility rights-of-way will be an ongoing effort, including along undergrounded lines, and is likely contributing to fuels buildup in the HFTD. GPI discussed these concerns in our comments on PG&E's 2023-2025 WMP.[121] An assessment of woody biomass tonnage generated through utility VM work is warranted and relevant to both understanding the scale of risk it may pose and linking VM residues to value-add end uses. Future consideration of more aggressive debris and wood removal requirements within high fire risk areas may be warranted. An OEIS-lead investigation of fuels build-up from VM activities is one option that would provide an assessment of problem scope and scale, and whether updated guidance for VM wood and debris management standards should be developed.

C. PG&E has expanded to include fuels treatment work and VM residue applications through partnerships. Ongoing progress should be an objective for all utilities.

PG&E reports an expanded portfolio of fuels management treatments and VM residue management pathways through partnerships.[122] It cites recent work indicating the value of fuels reduction and suggests a role for utilities as enablers of fuel reduction efforts beyond utility rights-of-way as a wildfire consequence mitigation. PG&E references a preliminary cost-benefit

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[120] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 586.
[121] COMMENTS OF THE GREEN POWER INSTITUTE ON THE 2023-2025 BASE WILDFIRE MITIGATION PLANS OF THE IOUs, May 26, 2023 pp. 7-18.
[122] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 386.

analysis but does not provide details. It also mentions fund matching opportunities for non-regulatory-driven fuel treatment work.

GPI generally supports PG&E's efforts to expand fuels treatment work through partnerships, especially those that amplify utility investments though matching funds. GPI recommends requesting that PG&E and other utilities report, in WMPs going forward, on the scope and scale of fuels treatment work planned and completed, utility funds allocated, as well as the amount and sources of grants and other supporting funds to complete fuels management work. Standardized and more detailed reporting on utility facilitated fuels management projects and associated partnerships will establish a baseline and example for all WMP filing utilities. Transparency into the total utility and external funds allocated will inform ratepayer impacts and cost-benefit assessments. PG&E should also report on its preliminary cost-benefit assessment for fuels treatment work as it pertains to fire risk to or from its assets.

PG&E also reports on its wood disposal biochar partnerships in Nevada and Lake Counties to improve wood disposal affordability and support long-term carbon sequestration. This constitutes at least one cradle-to-cradle opportunity for vegetation residues generated by PG&E's extensive vegetation management operations. However, more progress is necessary to advance scalable solutions for woody biomass disposal generated from the hundreds of thousands of trees removed and vegetation debris generated through PG&E's vegetation management activities.[123] PG&E previously reported 150,000+ tons of wood transferred through contracted wood yards.[124] The issue remains salient as utility VM programs respond to tree mortality rates and implement annual VM work.[e.g.125, 126] Managing wood residues through the development of wood product markets and bioenergy infrastructure is an objective of California agencies, including through CalFIRE grants, the Governor's Office of Business and Economic Development, CARB's 2022 Scoping Memo recommendations, and the CPUC BioRAM program for bioenergy, which

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[123] COMMENTS OF THE GREEN POWER INSTITUTE ON THE 2023-2025 BASE WILDFIRE MITIGATION PLANS OF THE IOUs, May 26, 2023, p. 4.
[124] COMMENTS OF THE GREEN POWER INSTITUTE ON THE 2023-2025 BASE WILDFIRE MITIGATION PLANS OF THE IOUs, May 26, 2023 p. 11.
[125] **California Department of Forestry and Fire Protection (CAL FIRE).** (n.d.). *California's Forests and Vegetation Treatment Program Map Journal*. ArcGIS StoryMap. Retrieved May 21, 2025, from https://calfire-forestry.maps.arcgis.com/apps/MapJournal/index.html?appid=3457736fb0dd45f98d41ab4030ebf048.
[126] GPI was unable to locate updated USFS Forest Health Protection Aerial Detection reports.

utilizes feedstock sourced from wildfire High Hazard Zones.[127,128,129,130] Developing cradle-to-cradle pathways for utility VM woody biomass, versus cradle-to-grave disposal, can offer value-add in support of fuels management associated with VM activities required for the foreseeable future.

D. PG&E should provide a scope, timeline, and milestones, for pilot programs that evaluate the use of remote sensing technologies in vegetation inspections.

PG&E's 2026-2028 WMP states:

> In 2025, PG&E will use data gathered from proven remote sensing technologies to analyze how distribution inspections could be further evolved to incorporate remote sensing techniques. − Remote sensing techniques that will be considered could include satellite, Light Detection and Ranging (LiDAR), ortho imagery, or other available technology that can provide accurate and efficient insights into vegetation risk. − PG&E may consider utilizing remote sensing in lieu of ground-based inspections on electrical spans that typically have no trees around the lines, to provide customers with a more cost-effective solution. This is based off the comparison of remote sensing detections versus ground-based identification in locations that typically have no or limited trees with the potential to impact PG&E facilities.[131]

PG&E's is proposing remote sensing pilots for vegetation inspection applications. While various applications for LiDAR have been explored in WMPs ongoing assessments and alternative low-tree density applications may prove beneficial to PG&E as well as for other Utilities. PG&E should provide a pilot scope, timeline, and reporting milestones. Without reporting requirements a failed pilot may go un-reported in future WMPs. However, positive or negative outcomes can provide useful information to other utilities.

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[127] **California Department of Forestry and Fire Protection (CAL FIRE).** (n.d.). *Wood Products and Bioenergy Program*. Retrieved May 21, 2025, from https://www.fire.ca.gov/what-we-do/natural-resource-management/climate-and-energy-program/wood-products-and-bioenergy.
[128] **Governor's Office of Business and Economic Development (GO-Biz).** (n.d.). *Wood Product and Biomass*. Retrieved May 21, 2025, from https://business.ca.gov/industries/wood-product-and-biomass.
[129] California Public Utilities Commission (CPUC). (n.d.). *Bioenergy Renewable Auction Mechanism (BioRAM)*. Retrieved May 21, 2025, from https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-procurement-programs/rps-bioram.
[130] **California Air Resources Board (CARB).** (2022). *2022 Scoping Plan for Achieving Carbon Neutrality*. Retrieved May 21, 2025, from https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf pp. 251-252.
[131] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 363.

VII. Integrated Distribution System Planning

A. Wildfire risk informed CBRs may become an input to distribution system planning and therefore must include the full suite of overhead distribution system mitigations as a package.

D.24-10-030 Ordered (emphasis added):

> No later than December 15, 2025, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall submit a Tier 3 advice letter proposing a method(s) that calculates and considers whether the increased project costs from the increased sizing of any related assets are less than or equal to the risk-adjusted benefit from avoiding future projects to upgrade grid capacity. Utilities may propose other factors to be considered towards calculating costs and risk-adjusted benefits. Utilities' proposal shall allow for future evolution of the Distribution Planning and Execution Process and should not become a barrier to future changes in that process. The advice letter shall also answer the following questions: (1) How does the proposed method maintain the flexibility of the distribution planning process, and allow for that process to develop over time; (2) How does the proposed method estimate the increased costs for current projects, and how can this estimate change or improve over time? <u>Include increased costs for wildfire mitigation and associated Rulemaking (R.) 20-07-013 Risk-based Decision- making Framework (RDF) cost benefit ratio data;</u> (3) <u>How does the proposed method incorporate cost effectiveness and cost efficiencies?</u> (4) How does the proposed method adjust for risk and potential risk reduction when considering potential future capacity projects, and how can this adjustment change or improve over time; (5) How does the proposed method estimate cost of future distribution capacity projects, (i<u>ncluding increased costs for wildfire mitigation and associated R.20-07-013 RDF cost benefit ratio data</u>) and how can this estimate change or improve over time; and (6) <u>How does the proposed plan address projects planned in the high fire threat districts or in areas of wildfire risk, or projects that will require new lines to be built that cross into the high fire threat districts?</u>

Increased costs for wildfire mitigation and the CBR is dependent on the risk mitigation package selected and how the mitigation packages are designed. As these WMP developed assessment tools are carried into an integrated system planning paradigm it will be imperative to account for a comprehensive overhead distribution system mitigation package that includes existing assets as well as grid modernization and DER/microgrid investments. It is therefore critical to migrate CBR and risk analyses towards valuing a comprehensive overhead distribution system mitigation package that includes pre-existing and available investments. Developing a CBR for entirely new overhead system mitigation packages may also be necessary for comparison to an underground solution for distribution system expansions within the HFTD. As details are release on PG&E's IGP, we look forward to further integrated system planning efforts.

B. WMP applications are a value-creation pathway for DER and grid modernization investments.

Gabriel Petlin, CPUC Supervisor in Distribution Grid Planning & Energy Storage stated:

> "It's become apparent perhaps that the team that is responsible for presenting and operationalizing the grid mod. technologies is not necessarily the same team that drives the value creation that is built upon those technologies and so you are in a position of having to present the rational for the investments but someone else seems to be responsible for capitalizing on those investments. And it does create a challenge I think for the GRC, almost like a split screen situation where you look at one screen and you see a very compelling set of arguments for some really interesting technologies that seem to hold a lot of promise and really do seem like they could really benefit. But on the other hand, the other screen, you see the CapEx for distribution just going up. It's almost like a disconnect…we can be both optimistic and open minded to the grid modernization investments, but at the same time we have to be weary of the growing capital revenue requirement for distribution and wondering when are we going to start seeing that coming down?[132]

This statement neatly summarizes a core issue with PG&E's WMP. The investments in Advanced Distribution Management Systems (ADMS) are linked to WMP wildfire and reliability risk management applications and pilots that include but are not limited to "improvements in efficiency of EPSS and PSPS event execution," "scale VGI use cases including V1G and V2X,"[133] "Dispatch DERs as NWAs …[to] relief load during summer,"[e.g.134] "Integrate DERMS w/ grid edge computing platforms to optimize at the hyper local level."[135] The Smart Inverter Operationalization Working Group also identifies applications for microgrids that mitigate the impacts of wildfire and related outages.[136] However, the WMP EPSS and PSPS plus DER and microgrid applications for wildfire and reliability risk management, *which are the value-creation outcomes of grid modernizing ADMS and smart inverters*, are not being adequately valued in the WMP nor fully leveraged to reduce distribution CapEx costs.

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[132] PG&E Grid Modernization Plan Workshop 20250313 1913 1. March 13, 2025. (3:02) Available at https://www.youtube.com/watch?v=4vVdlO6zOXA (Accessed May 22, 2025)
[133] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 231
[134] Ibid, p. 286
[135] PG&E 2027 Grid Modernization Plan Workshop 20250313 Slides.
[136] Smart Inverter Operationalization (SIO) Working Group Report Business Cases and Use Cases February 1, 2024

Essentially, PG&E is investing in a highly modernized grid that improved EPSS and PSPS event implementation and that will support DER solutions to wildfire risk-induced outages, while at the same time downplaying the value of improved EPSS/PSPS events and DER already deployed. The high cost, undergrouding first paradigm does not leverage these investments and instead minimizes them, often layering on CapEx costs where substantial risk reducing and cost-effective overhead system investments have already been made.

It is imperative that wildfire mitigation planning specifically quantifies the residual location-specific impacts of EPPS and PSPS events plus existing and planned DER CBR as part of a holistic overhead distribution system risk mitigation package that leverages the value-creation potential of grid modernization investments. An undergrouding-first paradigm duplicates existing and incremental overhead system mitigations and the value-creation opportunities intended to justify grid modernization, thereby mitigating a dwindling residual risk margin at high cost.

C. Distribution system electrical overloading, heat waves, and related wildfire risk should be studied and interim and long-term solutions developed.

GPI commends PG&E for analyzing and reporting on ignition risk related to asset electrical overloading.[137] Increasing customer load plus heat waves exacerbated by climate change can overload existing electrical infrastructure (e.g. conductors, transformers, etc.), resulting in operations outside manufacturer limits (e.g. high heat). PG&E identified multiple assets at risk of failure and subsequent ignition due to overloading:

- Capacitor ignitions – Overloaded – 13 percent[138]
- Distribution connector and splice ignitions – Overloaded – 7 percent[139]
- Distribution conductor ignitions – Overloaded – 13 percent[140]
- Transmission conductor ignitions – Overloaded – 6 percent[141]
- Distribution transformer ignitions – Overloaded – 30 percent[142]
- Transmission insulator ignitions – Overloaded – 10 percent

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137 Distinguished from pole “structural” overloading.
138 PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 260.
139 Ibid, p. 264.
140 Ibid, p. 268.
141 Ibid, p. 270.
142 Ibid, p. 286.

PG&E states (emphasis added):

> PG&E will underground approximately 1,077 circuit miles of distribution lines between 2026 and 2028, effectively eliminating ignition risk in those areas and enabling resilience and reliability for other climate hazards such as *high heat* and more severe winter storms.

Excessive focus on undergrouding as a solution once again erases the value-creation offered by right-sized overhead distribution systems supported by existing and planned grid modernization and DER investments. Wildfire risk associated with electrical overloading can presumably be mitigated through right-sized *overhead* distribution system packages that increase distribution system capacity based on extended (e.g. 10-year) customer load forecasts (i.e as now required via D.24-10-030).

This risk can also be mitigated by timely distribution grid "right-sizing"—A need that can be better supported by more rapid overhead distribution system mitigation deployment compared to an extended 10-year undergrouding plan. In fact, D.24-10-030 finds:

> The Staff Proposal contends this impending load growth requires a more robust and forward-looking [Distribution Planning and Execution Process] DPEP. However, the Staff Proposal asserts that current utility processes and regulatory requirements may hinder the move toward an improved DPEP. In the case of PG&E, other extenuating circumstances, such as prioritizing wildfire hardening, may further exacerbate this hindrance. These external influences have also set the underlying conditions for an increase in customer energization delays…[143]

And

> According to the Staff Proposal, distribution capacity project delays and lengthy energization timelines in the PG&E service territory have been caused by the redirecting of funds to wildfire-related work.[144]

Timely addressing distribution system grid needs necessary to serve increasing customer demand, which can exacerbate overloading risk and slow DER interconnection, is at risk due to the prioritization of wildfire hardening. In essence, the focus on slow and high-cost wildfire mitigations are having a cascade of negative impacts on customer service timelines, DER deployment, and necessary distribution system upgrades in PG&E's territory.

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[143] PG&E 2026-2028 Wildfire Mitigation Plan, April 4, 2025, p. 26.
[144] Ibid, p. 125.

In addition to upsizing wildfire hardened "wire" solutions (e.g. CC, exempt fuses, etc.), DER and demand response (DR) could provide load shedding services during heat waves, reducing distribution system load and overloading risk that drives asset ignitions. Deployed and in-progress grid modernization efforts are likely the tool that can enable this value-creation for existing DER deployments and DR programs.

All IOUs should be ordered to investigate the impact of electrical overloading on distribution and transmission system ignitions, including during heat wave events. Utilities, including PG&E, should be ordered to develop overhead mitigations that leverage existing resources as well as novel solutions to mitigate overloading ignition risk for both the interim and long-term. The majority of the distribution system within the HFTD will persist as overhead assets, even if PG&E's undergrouding plans are approved. Solutions to wildfire risk caused by electrical overloading should be integrated into the overhead system risk mitigation package and included in future overhead system CBRs.

D. Report on any applications of utility wildfire risk models to integrated system and distribution planning applications.

Through our work in the Integrated Resources Planning Proceeding and High Distributed energy Resource Proceeding, GPI has become aware that infrastructure siting and planning decisions in the CPUC busbar (i.e. substations) mapping process and the IOU distribution planning process (DPP) are informed by the HFTD map.[145] There is some agreement that the HFTD map is outdated and would benefit from a regular update schedule. Furthermore, utilities granular risk models have shown that wildfire risk varies within the HFTD Tier 2 and 3, such that higher risk can be located within lower risk Tiers or extends beyond the HFTD. In addition to needed HFTD updates, it may be prudent to consider applying granular wildfire and reliability risk models in the transmission and distribution planning processes to support the sustainable expansion of the distribution and transmission systems. If PG&E (and other IOUs) is already employing their wildfire and reliability risk model outputs in the DPP, a summary of the intersecting applications should be provided to improve transparency into integrated planning.

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[145] California Public Utilities Commission, Energy Division. *Methodology for Resource-to-Busbar Mapping for the Annual TPP*. REV-2024-09-06, September 2024. P. 24.

GPI looks forward to substantial advancements in this area through PG&E's IGP team and orders from the CPUC via D.24-10-030.

E. Utilities, including PG&E, should begin to report on updated HFTD system design standards and overlapping asset modification workstreams.

The utilities continue to gather data on system hardening effectiveness, transition pilots to programs, and expand their wildfire and reliability risk mitigation "toolbox." While the WMP has largely focused on retrofitting the existing distribution system, customer demand continues to rise and the WUI expands.[146] Both can drive distribution system expansions within the HFTD. PG&E's Grid Resources Integration Portal displays planned and in progress Distribution Investment projects the intersection with the HFTD, which include new feeders that may increase the distribution system footprint with the HFTD.[147]

GPI has previously noted that wildfire risk models developed in the WMP will not only guide existing system overhaul investments, but also new infrastructure design. PG&E's comments during the 2026-2028 IOU WMP workshop, regarding break away service connections versus undergrounding service drops, referenced in-development decision making as it pertains to updated, standardized system designs informed by wildfire risk.[148] To date, reporting on updated standards for grid assets is largely focused on exempt versus non-exempt equipment (e.g. fuses, lightening arrestors, etc.). To our knowledge there is no other active regulatory process or agency tasked with reviewing utility infrastructure design for distribution system expansions (i.e. new infrastructure) within the HFTD. While expansion of the distribution system within the HFTD may be slower compared to densely populations regions, this growth should not be overlooked. Utility reporting on new build standards informed by granular wildfire risk is relevant to wildfire burn areas as well as WUI growth and increasing customer demand. GPI recommends issuing an ACI to initiate this process and updating future WMP guidelines to better

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[146] **U.S. Department of Agriculture, Forest Service, Northern Research Station.** (n.d.). *Wildland-Urban Interface (WUI) Growth Project*. Retrieved May 21, 2025, from https://research.fs.usda.gov/nrs/projects/wuigrowth
[147] **Pacific Gas and Electric Company (PG&E).** (n.d.). Grid Resources Integration Portal *(GRIP)*. Retrieved May 21, 2025, from https://grip.pge.com/.
[148] 2026-2028 IOU WMP workshop. May 21, 2025.

capture utility integrated distribution system planning and design standard development as it pertains to an expanding distribution system within the HFTD.

Conclusions

We respectfully submit these comments on the 2026-2028 WMP of PG&E. PG&E's service territory has more land area classified as HFTD than any other California electric utility company, and the company has a long and difficult history of both causing and suffering from severe wildfires. Thus, no utility has a greater imperative to take actions to mitigate wildfire risks and damages than PG&E. Optimal wildfire mitigation efforts have to conform to three major policy objectives: contain costs, enhance reliability, and promote safety and environmental goals. PG&E's 2026-2028 WMP succeeds on some issues, and falls well short on others. GPI offers a series of suggestions in these Comments for ways for the utility to improve its WMP plan and anticipated wildfire mitigation efforts.

For the reasons stated above, we urge both PG&E and the OEIS to adopt our recommendations herein.

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Respectfully Submitted,

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