TURN
THE UTILITY REFORM NETWORK

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Northern California
785 Market Street
Suite 1400
San Francisco, CA 94103
415 929-8876 •
Mark Toney, Ph.D., Executive Director

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

VIA EMAIL ONLY

April 7, 2020

Ms. Caroline Thomas Jacobs
Director, Wildfire Safety Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: TURN Comments Regarding the 2020 Wildfire Mitigation Plans

Dear Ms. Jacobs:

Pursuant to the directions in CPUC Resolution WSD-001, The Utility Reform Network respectfully submits the attached comments on the 2020 Wildfire Mitigation Plans, focusing on the plans submitted by Pacific Gas and Electric and by Southern California Edison.

Sincerely,

Marcel Hawiger
Staff Attorney

Cc: CPUC service list for R.18-10-007

TURN COMMENTS ON

2020 WILDFIRE MITIGATION PLANS

Submitted to the Wildfire Safety Division

April 7, 2020

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2020 WILDFIRE MITIGATION PLANS

I. Summary of Recommendations

TURN has reviewed the Wildfire Mitigation Plans primarily of Pacific Gas and Electric Company (PG&E) and the Southern California Edison Company (SCE). Based on our review of the plans, associated discovery responses, previous utility submissions in rate cases, and relevant legal documents, TURN makes the following general recommendations regarding any potential approval of the Wildfire Mitigation Plans (WMPs):

- TURN does not take a position on whether WSD should approve the WMPs, in light of the limited time afforded for review and analysis of the WMPs. However, if the WSD chooses to approve a WMP, it should clarify that any approval is limited to a determination that the utility has included all required statutory elements in its WMP. Approval of a WMP should not extend to the approval of the scope of proposed programs, a determination of whether the utility has proposed the optimal portfolio of mitigation programs, or authorization of any cost recovery.
- The WSD should find that the SCE and PG&E risk spend efficiency (RSE) showings, required by §8386(c)(10), are deficient and do not provide a basis for approving the proposed WMPs. The WSD should direct the utilities to score every program included in a utility's WMP, regardless of categorization, and to perform more granular risk analyses. Unless and until the utilities provide a more reliable and granular calculation of the RSE for proposed mitigation projects, the utilities cannot be found to have presented the optimal mix of proposed programs.
- The WSD should not authorize any program costs as appropriate for recording in the wildfire mitigation memorandum accounts simply because the utilities claim the programs are new or incremental. The utilities must be required to demonstrate incrementality in future cost recovery proceedings. The WSD should also clarify that, to the extent a utility program is rejected, it cannot use the fact that costs were included in a WMP as an opportunity to seek a second chance at recovery.

- While it is entirely appropriate and necessary for the utilities to improve their traditional asset inspection methods, the WSD should not deem compliance inspection and repair programs as new wildfire mitigation activities simply because the utilities chose to characterize them as new in their WMPs. WSD should direct the utilities not to include traditional maintenance inspection and repair compliance program costs in the wildfire mitigation memorandum accounts.
- The WSD and the Commission should prioritize modifications to the templates and metrics in 2020 and should incorporate TURN's previously proposed modifications to various metrics so as to better evaluate the effectiveness of different mitigation strategies.

TURN also evaluated some of the primary programs addressing vegetation management and grid hardening. The lack of complete and accurate risk data and analyses makes it impossible to reach definitive conclusions regarding the efficacy and design of the programs, and thus highlights the need for the WSD not to approve any particular scope or scale for these programs. TURN offers the following comments and recommendations regarding program design:

- With respect to utility vegetation management activities, the WSD should:
    - Require utilities to explain how trees are selected to be included in the utility's vegetation database, and require PG&E, or an independent third party, to explain why the number of trees it trims in Tier 2 and 3 were not proportionally similar to SCE's tree trimming volume.
    - Require the utilities, as part of their quality assurance (QA) efforts, to evaluate the reasons why trees cannot be trimmed to the 12-foot guideline in HFTD areas.
    - Not authorize PG&E's hazard tree removal program as proposed.
    - Direct the utilities to:
        - Require complete and transparent reporting of the number and percentage of trees trimmed to 12 feet;
        - Require complete and transparent reporting of the number and percentage of overhangs removed in both HFTD and non-HFTD areas;
        - Devote limited vegetation management contractor resources to trim all HFTD area trees to twelve feet, where possible;
        - Clear more overhangs in Tier 2 and 3 areas;

        - Devise a more appropriate plan to address blowing palm fronds;
        - Coordinate a statewide study to determine the best practices for removing hazard trees and compare the efficacy of that program to other trimming alternatives; and
        - Accelerate the use of LiDAR data to optimize tree trimming and removal.
- With respect to grid hardening activities, the WSD should:
    - Require the utilities to continue collecting all data necessary to evaluate the effectiveness of covered conductor installation and the effectiveness of alternative technologies, so as properly evaluate the desired scope of covered conductor deployment to the highest-risk circuits;
    - Support utility testing of optimal and cost-effective methods to harden poles against fires;
    - Require utilities to analyze whether greater deployment of remote fault indicators would be useful as an ignition reduction strategy;
    - Encourage the utilities to cooperate in investigating the potential use of emerging technologies.

II. WMP Approval Should Be a Limited Determination and Cannot Address Cost Recovery

A. The WSD Should Determine Whether Utility WMPs Include All Statutory Requirements

At the conclusion of the first-ever implementation of the Wildfire Mitigation Plan (WMP) review process, the Commission clarified in the 2019 WMP Guidance Decision:

> Approval [of a WMP] means that every WMP contains 19 elements that the SB 901 Legislature deemed essential to catastrophic wildfire mitigation. Those elements are aimed at ensuring an electrical corporation has plans in place to protect the public from catastrophic wildfire. Without SB 901, existing wildfire-prevention and other safety requirements might not include all of the elements on the list.

In its 2020 review of the WMP, the inaugural review of the WMP completed by the Wildfire Safety Division (WSD), approval should similarly be limited to a determination that the utility has included all required elements in its WMP. Approval of a WMP should not extend to the approval of the scope of the proposed programs or a determination of whether the utility has proposed the optimal portfolio of mitigation programs.

The time frame for the review and approval of the WMP is limited and the scope of the proposed plans are broad. Given the constraints of the schedule, the WSD cannot approve the plans as presenting the ideal or optimal mix of programs or the proper scope of work in each proposed program. The WSD can and should assess whether the utility properly followed the guidance documents to assess its wildfire risk, and whether the utility is properly pursuing a range of programs to minimize that risk. The WSD should provide utilities guidance on program design, based on its review of data and information from multiple California utilities, and based on comments provided by the Wildfire Safety Advisory Board and other stakeholders. It remains to the utility to demonstrate in a GRC or other cost recovery proceeding that its ultimate scope of work efficiently addresses the identified wildfire risks, considering various practical and operational constraints.

Section 8386(d) directs the WSD to "verify that the plan complies with all applicable rules, regulations, and standards, as appropriate."[1] The WSD should limit its findings to whether each utility has achieved "paper compliance." In other words, the WSD should determine that the utility has provided the required information and is prepared to implement a plan, rather than make a conclusion that the utility has fulfilled all compliance requirements. The resources and undertaking required to ensure that all WMP applicants are in actual compliance, rather than "paper compliance," is an enormous task that cannot occur in the time frame available for WMP review. The determination of actual compliance will occur as the utility implements its plan, through Commission inspection and extensive audits by the independent evaluators as well as the review of costs.

Approval of a WMP will signal to the utility that the WSD affirms that it has met statutory requirements. To the extent that the WSD identifies that a utility WMP is insufficient to meet those requirements it should reject that plan. WSD approval, however, doesn't excuse the utility

[1] Cal. Pub. Util. Code § 8386(d).

from its obligation to carry out its work consistent with the principles of just and reasonable ratemaking.

B. Any Decision on the WMPs Should Clarify that It Is Not Addressing Cost Recovery

The purpose of the wildfire mitigation plans is to describe programs and strategies specifically designed to limit the potential for "electrical lines and equipment causing catastrophic wildfires."[2] Due to the urgency of this safety critical work, the Legislature directed the Commission to authorize memorandum accounts where the utilities can record the costs for all work related "to implement the plan,"[3] and directed the Commission to consider whether those implementation costs were just and reasonable "in its general rate case application."[4]

AB 1054, and SB 901 before it, as well as the 2019 WMP decisions all clarify that approval of the wildfire mitigation plans does not address the reasonableness and recoverability of wildfire spending.[5] Any WMP decision should clarify at the outset that not only does the decision not address program costs, but that approval of any program as part of the WMP does not suggest that the WSD has determined the costs are reasonable. TURN recommends that, as the Commission did in the 2019 Guidance Decision, any decision proposed by the WSD and adopted by the Commission clarify both:

> [A]pproval of a WMP here is not dispositive of an IOU's ultimate cost recovery for the operations and maintenance costs of hardening its system, managing vegetation, increasing situational awareness and taking the other steps to mitigate wildfire risk.[6]

And

> Any provision in a WMP that represents that approval of the Plan constitutes a determination on cost, reasonableness, or prudency is disapproved.[7]

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[2] Cal. Pub. Util. Code § 8386(c)(3).
[3] Pub. Util. Code § 8386.4(a).
[4] Pub. Util. Code § 8386.4(b)(1).
[5] D.19-05-036 at 4.
[6] D.19-05-036 at 20.
[7] D.19-05-036 at 38.

Including this language will clarify to the utilities and future commissions that it remains the obligation of the utility to demonstrate that any program pursued is just and reasonable.

C. Utility Designation of Spending as Wildfire Related Should Not Give It a Second Opportunity to Seek Recovery After a Program Has Been Rejected

Section 8386.4(a) states that at the time the WMP is approved, the Commission "shall authorize …a memorandum account to track costs incurred to implement the plan." "[T]he commission shall consider whether the cost of implementing each …plan is just and reasonable in its general rate case application."[8] However "in lieu of [reviewing costs in the GRC the utility] may elect to file an application for recovery of the cost of implementing its plan as accounted in the memorandum account at the conclusion of the time period covered by the plan."[9]

Regardless of whether the utility decides to seek costs in a General Rate Case (GRC) or in a separate cost recovery proceeding, the utility should have only one opportunity to seek recovery of a cost. If the utility decides to pursue cost recovery and the Commission determines that the proposed program or scope is not reasonable, it should not have the ability to simply track costs in a memorandum account and try for recovery again. Not only should the utilities certify they have not previously recovered the costs of the program, but also that they have not previously requested the costs.

The language of the statute makes it clear that the utility only has one opportunity to seek recovery. Section 8386.4(b)(2), specifically state that its separate application for recovery is "in lieu of" seeking recovery in a general rate case. Merriam Webster defines "in lieu of" as "in the place of" or "instead."[10] Regardless of which venue the utility decides to pursue cost recovery in, the legislature did not intend to allow the utility to seek recovery in a second venue if they are not satisfied with the outcome in the first. Once a program or cost has been rejected, whether on

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[8] Cal. Pub. Util. § 8386.4(b)(1).
[9] Cal. Pub. Util. § 8386.4(b)(2)
[10] See: https://www.merriam-webster.com/dictionary/lieu

a recorded or forecast basis, absent compelling evidence otherwise, the utility cannot try for recovery again.

The WSD should specify that it is not approving the scope of the wildfire mitigation plans or the reasonableness of costs. Including clear language to this end puts the utilities on notice they will have to prove the reasonableness and incrementality of any costs recorded in the WMP memorandum accounts in future cost recovery proceedings. The WSD should also clarify that, to the extent a utility program is rejected, it cannot use the fact that costs were included in a WMP as an opportunity to seek a second chance at recovery.

D. The RSEs Provided by SCE and PG&E Do Not Demonstrate That the Scope and Mix of Programs in Their Proposed WMPs Are Optimal

TURN recommends that the WSD Decision on the WMP clearly state that the risk showings by SCE and PG&E are deficient and do not provide a basis for approving the proposed WMP. Section 8386(c)(10) requires the WMP to include:

> A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of Safety Model Assessment Proceeding and Risk Assessment Mitigation Phase filings.[11]

Ultimately, the 2019 PG&E WMP decision recognized that, "[b]ecause the WMPs do not include these key details [related to risk], it is not possible to determine whether the portfolio of mitigations PG&E has selected for its WMP are optimal."[12] The 2020 WMPs filed by SCE and PG&E similarly fail to provide detail sufficient for the WSD to determine that the utilities have identified the optimal combination of programs and scope of work. The WSD decision on the 2020 WMPs should include a statement similar to the one in the 2019 PG&E Decision stating that the WSD cannot conclude that the WMPs are optimal. Further the WSD should clearly state that the RSE showings in the 2020 WMP are deficient and have not provided any basis for adopting those plans as reasonable on a risk basis.

[11] Cal. Pub. Util. Code § 8386 (c)(10)
[12] D.19-05-037 at 50.

In particular, as discussed below, SCE and PG&E have not calculated their RSEs consistent with the Settlement and at a sufficiently granular level to enable the utility to identify the optimal portfolio of programs. Even if the WSD were to accept the incorrectly calculated RSEs, the values have not been provided across all programs, leaving the RSE inadequate as a tool to determine whether the proposed programs are directionally accurate.

1. The WSD Cannot Conclude that PG&E and SCE Have Developed RSEs Consistent With the Process Required in the SMAP Settlement

The WSD Guidance directs the utility to include the Risk Spend Efficiency (RSE) for each proposed program.[13] As defined by the WSD in the Guidance Documents, RSE is "[a]n estimate of the cost-effectiveness of initiatives, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs."[14] In the Safety Model Assessment Proceeding (SMAP), the Commission has adopted a Settlement that outlines an approach to calculating the RSE to be used in each utility's Risk Assessment and Mitigation Plan proceeding.[15]

The RAMP proceeding and the General Rate Cases (GRC), and not the WMP proceeding, are the venues for the utility to present their risk approach and parties to provide feedback. SCE stated that the basis for its RSE calculations is "similar to that used in SCE's 2018 RAMP report and the 2021 GRC."[16] However, SCE's 2018 RAMP Report was not required to follow the Settlement approach for calculating RSE.[17] As a result, SCE is using an outdated approach to calculating the RSE. TURN submitted comments in the 2018 SCE RAMP explaining the problems with the SCE calculation of its RSEs.[18] SCE's Testimony in its GRC suggests that TURN's recommendations for correcting the RSE have not been implemented.[19] While SCE

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[13] R.18-10-007, ALJ Ruling, December 16, 2019, Attachment 1 (WMP Guidelines), p. 50. Hereinafter referred to as the "Guidance Document."
[14] Guidance Document at 12.
[15] D.18-12-014, OP 1.
[16] SCE WMP at 5-45.
[17] D.18-12-014 at 35.
[18] Comments of The Utility Reform Network on Southern California Edison Company's 2018 Risk Assessment and Mitigation Phase Report and the Associated SED Report, I.18-11-006 (CPUC June 14, 2019).
[19] Supplemental Testimony on Risk-Informed Strategy and Business Plan, A.19-08-013 (CPUC Apr 3 2020) at 2-3.

argues that its approach is consistent with the SMAP Settlement, until it has been vetted in a RAMP and the following GRC, the results of SCE's risk analysis are suspect. In any event, to the extent SCE has not fully implemented the methodology in the S-MAP settlement, it has not used the best, Commission-approved methodology for calculating RSE.

PG&E states that its "method for evaluating safety risk and wildfire risk is consistent with the requirements of the S-MAP settlement agreement;" however, the utility has not yet filed a RAMP using the Settlement approach.[20] As PG&E has not presented its RAMP or a GRC based on that RAMP, it is doubtful that its RSEs are accurate or have been correctly calculated. Indeed, there is good reason to believe that PG&E's RSE are not accurate. Recently, TURN sent PG&E a letter outlining numerous preliminary concerns about the methodology that PG&E has signaled that it will use in its upcoming RAMP submission that is supposed to implement the SMAP Settlement.[21]

At this time, the RSEs, where provided, are not a reliable assessment of the mitigation capabilities of a program. A clear example that the RSE is not yet a reliable tool for shaping the WMP is the high scores calculated for Public Safety Power Shut Off (PSPS) programs by both SCE and PG&E. SCE highlights that "programs with higher RSEs such as PSPS are not necessarily the preferred long-term solution over covered conductor installation with comparatively lower RSEs."[22] While "[Public Safety Power Shutoff (PSPS) has a relatively high RSE,"[23] SCE acknowledges that "it did not incorporate the secondary impact of PSPS."[24] With this admission, SCE clarifies that for the purposes of comparing mitigation alternatives, SCE did not include the impact of its PSPS on its customers. The true negative impact of the PSPS is not felt by the utility itself, but rather by the customers impacted. Without power, a business may lose multiple days of business, children may be out of school or someone may miss a paycheck. Worse, power outages pose risks to health and safety, including to customers who rely on

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[20] PG&E WMP at 5-268.
[21] February 19, 2020 Letter from Thomas Long (TURN) to Tessa Carlberg (PG&E) regarding TURN's Concerns with PG&E's Methodology for Risk and Mitigation Assessment ("TURN's Pre-RAMP Letter to PG&E"), This letter is attached as Attachment 1 to these comments.
[22] SCE WMP 5-44.
[23] SCE WMP 5-132
[24] Data Response TURN-SCE-03-6b. (TURN does not attach data responses, as they are contained on the IOU WMP discovery websites.)

electric-dependent medical equipment. If the utility is not including some estimate of these negative outcomes of its decision to shut off power, the RSE will never be an accurate reflection of the impacts of this mitigation. The problem that SCE's admission highlights is not with the RSE but with the inputs to and calculation of the RSE.

Similarly, PG&E's RSE for PSPS is much higher than any of the other scored mitigations, in part because it also appears that the utility has not included the negative impacts of a PSPS on the public.[25]

2. Contrary to the WSD Direction, PG&E and SCE Have Not Provided an RSE for Every Proposed Program

Even if the RSEs that were provided were correct, SCE and PG&E have only provided RSEs for some of the proposed programs. SCE has not scored pilot projects, traditional programs, enabling activities, supporting activities or activities with insufficient data.[26] PG&E states that the "RSEs have been calculated for four mitigation programs related to wildfire risk."[27] Similar to SCE, PG&E has not provided RSE for projects categorized as foundational, control, or exploratory[28] TURN agrees with the WSD that failure to provide the RSE for certain categories is "not acceptable."[29]

The WSD should, again, direct the utilities to score every program included in its WMP regardless of its categorization. SCE, for example, argues that it cannot provide RSEs for traditional programs because "it is difficult to measure the incremental impact of a preexisting program."[30] TURN will not dispute that this task may be difficult, but difficulty does not relieve the utility of its obligation. The utilities should score every program using data when available and Subject Matter Expertise to estimate inputs when necessary to estimate the RSE for every

[25] See PG&E Tables 23 and 26. See also TURN's Pre-RAMP Letter to PG&E, p. 6, item 6.
[26] Data Response TURN-SCE-03-05.
[27] PG&E WMP at 5-227.
[28] See PG&E Attachment 1, Tables 22-30.
[29] See PG&E Data Response WSD_001-Q42-PGE-43879-F-136.
[30] Data Response TURN-SCE-03-05

program.[31] The estimates and assumptions can then be provided to the intervenors and the WSD for consideration during the assessment of the WMP.

The important potential of the RSE is the ability to compare the cost-effectiveness of different programs. This only works, however, if the RSE is provided for all programs, even existing compliance and foundational programs. Providing an RSE for all programs along these lines can help the WSD to determine whether the proper compliance projects are in place or if there are other compliance requirements that should be adopted.

3. Where Provided, the RSE is Not Granular and Therefore Will Not Properly Target Mitigations

SCE and PG&E have not provided RSE on a granular enough basis to determine whether the proposed mix of programs is optimal. SCE admits that it "calculated the RSEs at the system level."[32] Similarly, PG&E states that for the purposes of RSE, "ignitions are broken down to six tranches to reflect similar risk profiles."[33] These tranches are overly broad:

- HFTD – Ignition Associated with Distribution: Ignitions in HFTDs associated with Distribution assets.
- HFTD – Ignition Associated with Transmission: Ignitions in HFTDs associated with Transmission assets.
- HFTD – Ignition Associated with Substation: Ignitions in HFTDs associated with Substation.
- Non HFTD – Ignition Associated with Distribution: Ignitions in non-HFTDs associated with Distribution assets.
- Non HFTD – Ignition Associated with Transmission: Ignitions in non- HFTDs associated with Transmission assets.
- Non HFTD – Ignition Associated with Substation: Ignitions in non-HFTDs associated with Substations.[34]

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[31] D.18-12-024 at Attachment A, Appendix A at A-18, Settlement Agreement Line 31.
[32] Data Response TURN-SCE-03-03
[33] PG&E WMP p. 4-8.
[34] *Id.*

Contrary to the purpose of tranches as defined in the S-MAP Settlement,[35] it is unlikely that every single segment across the system or in each of the six tranches reflects the exact same risk profile.

The mitigation impact of a program will vary across the different segments in a system or in a tranche, and if these variations are not reflected in the RSE, the value of the RSE as a tool for targeting spend is lost. By failing to provide a more granular RSE, the utility cannot capture the optimal combination of programs.

The utilities have collected data on individual segments.[36] In the future, the segment level analysis should be provided to identify more granular tranches and more accurate RSE. A granular calculation of the RSE at the segment level may suggest a different combination of proposed mitigations than identified at the system level. While one mitigation may have a higher RSE at a system level, there is likely to be a wide degree of variation of RSE across segments with a different mitigation with a different mitigation proving most beneficial when RSE is provided on a segment by segment basis.

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[35] The SMAP settlement defines "tranche" as subgroups of assets or systems with like characteristics for purposes of risk assessment. D.18-12-014, p. A-4.

[36] For example, see: PG&E WMP Executive Summary-6-7: Over late 2018 and 2019, PG&E inspected all equipment within the HFTDs in our service territory to identify any structures or equipment that were damaged, degraded or could fail and potentially cause a fire …. PG&E uses inspection results to prioritize and manage equipment repair needs." PG&E Executive Summary at 12: In late 2018 and 2019, PG&E's meteorology team compiled one of the largest known high-resolution climatological datasets in the utility industry: a 30-year, hourly, 3 kilometer (km) spatial resolution dataset consisting of weather, dead and live fuel moistures and fire weather assessments, to improve identification of high-risk weather patterns.

SCE WMP at 5 "Deployed in 2019, the asset-level Wildfire Risk Model (WRM) estimates probability and consequence of ignitions using advanced analytics. The WRM's probability module uses machine learning capability to estimate the probability of an ignition from inherent equipment failure, current asset characteristics, or contact from a foreign object. The WRM's consequence module uses a fire propagation model that incorporates weather and fuel conditions along with other factors such as topography and housing and population density. The resulting ignition risk scores for each asset or circuit-segment location are used to target WCCP deployment, prioritize remediation of inspection findings, and guide our vegetation clearing activities." , Unless and until the utilities provide a more reliable and granular calculation of the RSE for proposed mitigation projects, the utilities cannot be found to have presented the optimal mix of proposed programs.

III. Utility Designations of Programs As "New" or "Exceeding Compliance" Are Not Sufficient to Find that the Programs Are New Wildfire Mitigation Activities

A. The Statutory Memorandum Accounts Are Not Intended to Subsume All Utility Spending

The WSD and the Commission should carefully evaluate a key issue – the potential overlap between traditional safety and reliability work and wildfire mitigation work. The reality is that traditional utility work to improve reliability and safety often focused on reducing faults and outages. But faults, especially those due to contact from vegetation or equipment failure, are also the cause of ignitions. Historical inspection and compliance work, as well as a multitude of utility programs to repair and/or replace various assets, were all intended to reduce the incidence of faults and/or outages and to ensure compliance with General Order regulations concerning asset conditions and utility inspection procedures.

It is not the purpose of the wildfire mitigation plans to subsume all of this traditional work as "wildfire mitigation work," to be recorded in the statutorily authorized WMP memorandum accounts. A conflation of regular maintenance and reliability work with wildfire mitigation work would render moot significant aspects of the traditional rate case. For this reason, while the Commission appropriately asked the utilities to describe all of their various inspection, repair and asset maintenance activities in the WMPs, it also directed the utilities to identify whether an activity is "existing" or "new," and also whether a program is implemented "in compliance" with existing regulations or "exceeds current regulatory requirements."[37] As the Commission already cautioned PG&E in approving the 2019 wildfire mitigation plans:

> We find that the accelerated approach to inspections and maintenance described in PG&E's WMP complies with the requirements of SB 901, Pub. Util. Code Section 8386(c)(9). Still, this finding does not give PG&E a blank check for the activities described in its Plan. PG&E is currently placing WSIP costs in a memorandum account. **At such time as PG&E seeks cost recovery, PG&E may need to show cost-effectiveness and how elements of its WSIP are**

[37] Guidance Document, p. 50-51.

> **necessary to address new risks, over and above what is required by GO 165**.[38]

Unfortunately, the utility classifications of programs as “existing/new” and “in compliance/exceeds compliance” are inconsistent and unclear, and do not allow for an accurate determination of which programs are actually new wildfire mitigation programs that are not already funded through rates. This is yet another reason why the Commission should not authorize any explicit scope of work even if it approves these wildfire mitigation plans.

B. The Utilities Have Inconsistently Classified Similar Initiatives

PG&E has classified several programs as “new” and/or “exceeding compliance,” and PG&E apparently intends to record some or all of the costs for these programs in wildfire mitigation memorandum accounts. Both the nature of the work, as well as a comparison with SCE’s programs, suggests that PG&E is misclassifying these programs.

For example, initiative 1 in the “asset management and inspections” category is described as “detailed inspections of distribution electric lines and equipment.” The Guidance Document instructed the utilities to explain the rationale “for any utility ignition probability-specific … over and above the standard inspections.[39] SCE classifies this activity as “existing” and forecasts $7,890,794 for this work for 2020-2022. PG&E classifies this activity as “existing/new” and forecasts $242,408,161 for this work for 2020-2022, and states that the work would be “partially” recorded in wildfire memorandum accounts. There is little to explain the significant difference in classification or costs between the two utilities. Similarly, PG&E classifies its “distribution corrective action” program[40] as “existing/new” and “exceeding compliance,” while SCE classifies its program[41] as “new” and “in compliance.” Both utilities intend to record costs in the wildfire mitigation memorandum accounts. There is little

[38] D.19-05-037, pp. 12-13 (footnotes omitted, emphasis added).
[39] Guidance Document, p. 58.
[40] PG&E Table 23, Initiative 12-4.
[41] SCE Table 23, Initiative 12.1.

explanation of why PG&E's cost forecast is $443 million greater than SCE's forecast for these repair activities.

There are various other initiatives that are classified differently by PG&E and SCE, and the available information is insufficient to determine whether those differences reflect substantive program differences or inconsistent classifications of existing programs. The WSD should not authorize any costs programs as appropriate for recording in the wildfire mitigation memorandum accounts simply because the utilities claim they are new or incremental. The utilities must be required to demonstrate incrementality in future cost recovery proceedings.

C. Various Inspection and Repair Programs Appear to Address Historical Deficiencies in Compliance Activities and Are Not Properly New Mitigation Programs

Even more importantly, the WSD should be extremely cautious about authorizing any of the utilities' enhanced "inspection and repair" programs as new wildfire mitigation programs. There are several strong indications that the enhanced inspection and repair work reflects a need to fix deficiencies due to poor historical maintenance, and represents compliance catch-up, not new wildfire mitigation activity.

For example, SCE explains that the result of its 2019 enhanced inspection program was to find over 600 Priority 1 conditions and over 65,000 Priority 2 conditions.[42] PG&E similarly explained in its September 2019 rebuttal testimony in its rate case proceeding that its enhanced "Wildfire Safety Inspection Program" discovered 177,000 maintenance tags in HFTD areas, far in excess of its annual tag discoveries.[43] While TURN agrees that these enhanced inspections are using additional methods, such as aerial drones, to inspect distribution assets, the upshot is that the utilities are finding new General Order 95 compliance violations and taking corrective actions to repair those violations.[44] Just because the utilities were not finding problems with their historical inspection practices does not make the new inspections or repairs a "wildfire" program. It makes

[42] SCE WMP, pp. 5-85 to 5-86.
[43] A.18-12-009, Exh. PG&E-18v1, p. 2A-5. As a result of the need to deploy trained staff to repair all of these compliance issues, PG&E reduced the scope of its covered conductor program for 2020-2022 by more than half.
[44] GO 95 classifies violations into three priority levels. See, GO 95, May 2018, Rule 18-B1, p. I-10.

them a more effective GO 95 compliance program.[45] TURN is not at all suggesting that this work not be accomplished – indeed, it is critical. But it is work that the utilities likely should have been doing historically as part of their compliance obligations.

Similarly, SCE forecasts $93 million for transmission maintenance activities. SCE classifies this work as "new" and "in compliance," and SCE apparently intends to record these costs in the wildfire mitigation memorandum accounts.[46] But SCE explains that the work is entirely to perform repairs due to compliance violations, including primarily Priority 2 notifications.[47] There is no basis for recording these costs in the WMP memorandum accounts.

The difference in scope between PG&E and SCE on initiatives related to asset inspections and maintenance suggests PG&E has a greater amount of deferred maintenance work it is now doing, as illustrated below:

Table 1: Comparison of Inspection and Maintenance Initiatives for PG&E and SCE[48]

	PG&E	SCE	PG&E>SCE	PG&E/SCE
Circuit Data				
Overhead D Circuit Miles in HFTD Tiers 2/3	25,488	9,827	15,661	259%
Initiative Name				
Maintenance - T	$520,991,957	$93,980,237	**$427,011,720**	
Other Corrective - D	$981,209,192	$537,596,484	**$443,612,708**	
T tower M & Replace	$914,336,374	$17,075,345	**$897,261,029**	
D - Detailed Inspections	$242,408,161	$7,890,794	**$234,517,367**	
T - Detailed Inspections	$122,487,302	$3,401,221	**$119,086,081**	
Total	$2,781,432,986	$659,944,081	**$2,121,488,905**	**421%**

[45] TURN thus suggests that costs for these programs should be evaluated pursuant to traditional rate case ratemaking, not recorded in memorandum accounts statutorily authorized specifically to recover costs to prevent catastrophic wildfires.
[46] SCE Table 23, Initiative 12.2.
[47] SCE WMP, p. 5-73 to 5-74 (Section 5.3.3.12.2).
[48] Source: PG&E and SCE Tables 23, 24 and 25. These items include selected initiatives from those tables.

The table above shows that while PG&E has about 2.5 times more distribution overhead circuit miles in HFTD areas than SCE, PG&E intends to spend about four times more (or $2.1 billion more) than SCE on various "inspections and corrective actions" on its transmission and distribution system. PG&E provides no explanation of why its scale of inspections and repairs is so much greater.

For example, initiative 15 in the "Grid Design and System Hardening" section is "Transmission Tower Maintenance and Replacement." Both utilities apparently agree that these programs are already funded through rates and are not properly "a WMP initiative."[49] Nevertheless, PG&E classifies this activity as "New" and "Exceeds compliance" and forecasts a total of cost of $914,336,374 for 2020-2022,[50] while SCE forecasts only $17,075,345 for this activity.[51] PG&E explains that it used models and risk-informed analysis to identify "comprehensive replacement projects," presumably meaning the replacement of transmission towers. It is impossible to determine from the information why PG&E needs to spend almost a billion dollars on transmission tower replacement as a new wildfire mitigation program. TURN certainly agrees that functioning and reliable transmission towers are necessary to prevent catastrophes and ignitions. Why PG&E has not conducted such replacement projects in the past is a mystery. TURN can only surmise that PG&E has failed to properly maintain or replace its transmission towers historically, and is now claiming a need to replace these towers as part of "wildfire mitigation." Again, compliance activities absolutely help reduce ignition risk, but it is important that the WSD and the Commission not in any way approve utility claims that these are something more or different than traditional compliance activities.

D. The WSD Should Clarify That It Is Not Reviewing Non-Wildfire Programs or Costs

There are numerous programs and initiatives included in the WMP that are not classified as new wildfire mitigation programs, but are included in response to directions in the guidance document to describe various inspection and asset management programs. As discussed previously, some of these programs are intended to mitigate outages based on traditional

[49] For example, SCE WMP Sec. 5.3.3.15, p. 5-75.
[50] PG&E Table 23 and WMP, p. 5-137.
[51] SCE Table 23.

reliability concerns, and thus are quite relevant to assessing the full panoply of utility activities. The utilities include cost forecasts for these program in their tables. The WSD should clarify that if it is approving the plans, it is in no way approving the reasonableness of any cost forecasts for these non-wildfire mitigation programs; and it is certainly not authorizing any such costs to be recorded in wildfire memorandum accounts.

For example, PG&E forecasts $520 million in 2020-2022 for "Other Corrective Action – non-Enhanced Maintenance, Transmission."[52] These is absolutely nothing in PG&E's description of this work to suggest that this is not normal maintenance and upgrade work necessary to comply with basic regulations for transmission capacity and reliability, and PG&E is not claiming this work should be recorded in the wildfire memorandum accounts. [53] In discovery PG&E explained that the $461,723,000 of the forecast amount is for traditional capacity and reliability projects.

E. Conclusion

The Guidance Document appropriately asked the utilities to include in their WMP the full panoply of utility programs that relate to system inspections, repairs and asset management. Obviously, all programs that mitigate the risk of faults also reduce the risk of wildfires. However, these are not new programs that were specifically designed to mitigate the risk of ignitions in HFTD areas, particularly during dry and windy conditions.

While the utilities have self-classified programs which they consider "new" or "exceeding compliance," and have indicated which costs they intend to record in various wildfire mitigation memorandum accounts, the WSD should in no way approve the utilities' self-classification of programs. It is unlikely, given the compressed timeline, that the WSD can obtain sufficient data and information to conclude which programs and costs are truly new and/or incremental to costs already authorized in rates, and eligible for recording in the wildfire mitigation memorandum accounts. Thus, if the WSD approves these plans, it should make clear that the utilities bear the burden of demonstrating, in a future rate case or application seeking cost recovery, that any costs

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[52] PG&E Table 23, Initiative 12-3.
[53] PG&E WMP, pp. 5-131 to 5-132.

recorded in memorandum accounts truly qualify as new and incremental programs designed to reduce wildfire risk.

Moreover, the WSD can and should direct the utilities not to include traditional maintenance inspection and repair costs in the wildfire mitigation memorandum accounts. Traditional maintenance and inspection costs are forecast in utility GRCs, and TURN is concerned that utilities will have the opportunity to recover cost overruns or double-recover expenditures if such costs are allowed to be recorded in memorandum accounts. Further, it places unnecessary burden on parties and the Commission to address costs which should have never been recorded to wildfire memorandum accounts in the first place.

IV. The WSD and the Commission Should Incorporate TURN's Recommendations Concerning Metrics Necessary for Risk Analysis and Program Evaluation

The Commission has properly devoted significant resources to developing and standardizing various metrics that the utilities will use to monitor and measure risks and program performance. The utilities used these metrics for reporting data in the various Tables included with the WMPs.

The utilities will be spending billions of dollars on new and developing programs designed to reduce ignitions and wildfires. Proper measurement of program results will be critical for determining how well these programs are working, for improving program design, and for allocating resources to those programs that are most effective. Moreover, given the geographic and temporal variability of wildfire risk, there is no one-size-fits-all mitigation solution, and program effectiveness must be measured in conjunction with factors describing local site and weather conditions.

The ALJ Ruling of December 16, 2019, which provided the templates for these 2020 WMPs, included critical sections concerning metrics that will be used to "evaluate each utility's wildfire mitigation approach, progress, and results related to ongoing wildfire mitigation activities." Attachment 4 of the Ruling included recommended metrics that will be used to track both utility activities ("Progress Metrics") and utility performance ("Outcome Metrics"), normalized to allow comparison across different utilities and times.[54] The Ruling explains that these metrics "are in development and will continue to evolve."

TURN provided extensive comments in R.18-10-007 concerning metrics in three sets of comments filed on November 6 and November 18, 2019, and on January 7, 2020.[55] TURN provided specific proposals for modifications to various metrics to ensure proper measurement of both overall program effectiveness, as well as the effectiveness of individual mitigation measures. TURN also proposed modifications to the metrics adopted by the ALJ Guidance Ruling of December 16, 2020.

In its Phase 2 Decision 20-03-004, the Commission concluded that various updates to the templates and metrics would be made both by WSD and by the Commission in Rulemaking 18-10-007.[56] TURN urges both the WSD and the Commission to prioritize modifications to the templates and metrics in 2020. The utilities are moving fast to implement various programs and activities. It will be critical to ensure that scarce human and financial resources are directed toward the most effective programs, depending on particular site conditions. Proper measurement will be vital to guiding such choices.

V. Comments and Recommendations Regarding Program Design

A. Vegetation Management

1. PG&E May be Trimming Proportionately Fewer Trees in HFTD Areas than SCE

The majority of tree trimming work, even in HFTD areas, is conducted pursuant to the routine vegetation management (VM) program. **Error! Not a valid bookmark self-reference.** provides 2019 data on the total number of trees in utility databases and the number of trees trimmed by each utility, both through the routine VM and the enhanced vegetation management (EVM) program. **Error! Not a valid bookmark self-reference.** illustrates that while PG&E has almost

[54] R.18-10-007, ALJ Ruling, December 16, 2019, pp. 6-7, 33.
[55] TURN attaches the relevant portions of the November 6 and the January 7 comments concerning metrics as Attachment 2 to these comments.
[56] D.20-03-004, pp. 7-8.

four times the number of trees in HFTD areas in its vegetation database, it trimmed only about one-and-a-half times as many trees as SCE in Tier 2 and 3 areas.[57]

Table 2: Comparison of Tree Trimming for SCE and PG&E in 2019 in HFTD[58]

	Overhead Circuit Miles in HFTD	Total Service Territory Area In HFTD (sq mi)	2019 Number of Trees in Veg. Database in Tiers 2/3	2019 Trees Trimmed in Tiers 2/3
SCE	9,827	14,165	519,980	418,112
PG&E	25,488	37,900	1,960,863	552,348
PG&E/SCE	259%	267.56%	377.10%	132.11%

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Table 2 suggests that PG&E is proportionately trimming fewer trees than SCE, at least based on the number of circuit miles and trees in its database. TURN cannot conclude based on the available evidence whether these data reflect a problem with PG&E's tree trimming, or are justified by relevant differences in service territory characteristics or the criteria used for including trees in the vegetation databases.

[57] However, these data are for 2019 only, and the number of trees in each utility's database varies considerably from year to year.
[58] Sources: SCE Responses to TURN DR 003-12 and 003-13; PG&E Responses to TURN DR 012-03 and 013-01. TURN notes that: 1) the PG&E total includes trimming in both routine VM and EVM; 2) SCE increased its tree trims in T2/3 from 234,457 in 2018 to 418,112 in 2019.

With respect to routine vegetation management, the WSD should: 1) require all utilities to explain how trees are selected to be included in the utility's vegetation database, and 2) require PG&E, or an independent third party, to explain why the number of trees it trims in Tier 2 and 3 were not proportionally similar to SCE's tree trimming volume.

2. The WSD Should Evaluate the Need for Greater Compliance with the Twelve-Foot Clearance at Time of Trim "Guideline" in HFTD Areas Through Greater Data Collection by the Utilities

Rule 35 of General Order 95 imposes minimum clearance requirements (MCR), which specify that all trees must be trimmed to maintain a four-foot distance from power lines at all times in HFTD areas.[59] In addition to the minimum clearances that must be maintained at all times , Appendix E of Rule 35 recommends a twelve-foot "time of trim" clearance for all trees in HFTD areas, intended in part to ensure that minimum clearance requirements are maintained until the next trimming cycle. The twelve-foot guideline is not mandatory, but "should be established … where practicable,"[60] and the utilities can adopt even greater time of trim clearances based on consideration of multiple factors related to the vegetation, site conditions, geography, and conductor conditions.

In its WMP and data responses, SCE explains that starting in June 2019 it directed its routine vegetation management contractors to trim to twelve feet in HFTD areas where "achievable," subject to various operational constraints.[61] PG&E also responded that it directs contractors to comply with all the regulations in Rule 35, including the twelve-foot time of trim clearance guidelines in Appendix E, although PG&E did not clarify how it directs contractors to interpret the "where achievable" criteria.[62]

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[59] G.O. 95, Rule 35, Table 1. The MCR varies depending on voltage, but is four feet for most distribution lines in HFTD.
[60] General Order 95, Rule 35, Appendix E. See, also, D.17-12-024, pp. 101-102.
[61] SCE 2020 WMP, pp. 104-105; Data Response to TURN-SCE-003-011.
[62] PG&E Response to DR TURN 012-01 and 014-01 and 02. While the "Distribution Vegetation Management Standard" does not appear to have an explicit reference to Appendix E of Rule 35, PG&E states that it informs its contractors of these requirements. Apparently, PG&E expects its contractors to use best professional practices to trim trees without damaging the tree in a way that would lead to tree mortality.

SCE conducted quality control inspections in 2019 and found that 58% of trees were within the guideline clearances.[63] PG&E's quality assurance inspections found that 71% of trees were trimmed to the twelve-foot clearance guideline.[64]

TURN appreciates there are various limitations that preclude achieving the twelve-foot clearance guideline, particularly related to the need not to damage the tree. The information and data provided by the utilities is insufficient to determine whether contractors are complying sufficiently with the 12-foot guidelines in HFTD areas. TURN recommends that the WSD require the utilities, as part of their quality assurance (QA) efforts, to evaluate the reasons why trees are not trimmed to the 12-foot guideline. All efforts should be made to promote clearance to the guideline in situations where the constraint does not involve a biological tree condition, but can be overcome by additional efforts, such as communicating with the property owner.

SCE intends to develop an Integrated Vegetation Management Plan to promote low-growth habitats using various control methods,[65]and also an integrated vegetation management platform that will integrate programs and data to enhance efficiencies, initially just for the two tree removal programs (hazard tree and DRI).[66] TURN supports efforts to integrate databases and information to optimize tree trimming schedules and incorporate data on vegetation growth based on species type and local conditions. However, as discussed later, the utilities should also incorporate LiDAR data in their vegetation management efforts.

3. The Scope of PG&E's Hazard Tree Removal Program Appears Excessive and May Reflect Poor Resource Allocation

Both PG&E and SCE have developed "enhanced vegetation management" (EVM) programs designed to "reduce the risk of trees, limbs and branches contacting power lines."[67] These programs are new and evolving, but primarily include increased trimming distances, the removal of overhanging branches above power lines, and the assessment and removal of trees that are

[63] SCE Response to DR TURN 03-017.
[64] PG&E Response to DR TURN 012-01 and 014-04. PG&E's QA was based on a review of approximately 10% of the trees trimmed in HFTD.
[65] SCE WMP p. 97.
[66] SCE WMP p. 104.
[67] PG&E WMP p. 5-175.

identified as "hazard trees," meaning that they have the potential to fall and contact power lines based on their size, distance from power lines, and an assessment of tree and site conditions.[68] While TURN supports reasonable programs to remove overhang and increase vegetation distances in utility HFTDs, the utilities have never justified why mass removal of predominately healthy trees is necessary or reasonable given the low risk posed by such trees and the fact that blow-ins can occur from miles away. The proposed spending by both utilities for various EVM activities, as shown in Table 25,[69] is quite large:

Table 3: Proposed Scope of New Vegetation Management Activities Is Dominated by Inspections and Hazard Tree Removal

Initiative	Activity No.	PG&E (2020-2022)	SCE (2020-2022)	PG&E/SCE
D - Detailed Veg Inspections	2	$550,702,202	$34,189,618	1611%
T - Detailed Veg Inspections	3	$121,250,408	$1,527,095	7940%
Fuel Management	5	$76,891,000	$15,983,339	481%
LIDAR - T&D	7, 8	$77,170,500	$4,455,419	1732%
Enhanced Veg Inspections	9, 20	$329,209,605	$201,319,791	164%
Hazard Tree Removal	15	$1,388,314,652	$296,616,891	468%

SCE forecasts that it will evaluate about 75,000 trees per year in 2020-2022, and remove approximately 9,000 trees per year at a total three-year cost of about $185 million.[70] SCE also

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[68] For example, PG&E WMP pp. 5-176 to 5-177.
[69] From Table 25 of the WMPs. TURN assumes that the spending shown in Table 25 is for activities incremental to the routine vegetation management work authorized in rate cases.
[70] SCE 2020 WMP, p. 5-103 and Table 25, Initiative 16.1. TURN calculated the 9,000 removal figure based on SCE's 12% failure rate, which was used by SCE in its current GRC. However, SCE claims that it will actually remove an average of 20,000 trees per year in 2020-2022, based on its GRC forecast of 125,000 assessments. Data Responses TURN-SCE-004-01 and 02.

intends to remove the 10,000 trees it identified in 2019 but could not remove due to lack of permission from the Forest Service.[71] PG&E, on the other hand, expects to remove over 150,000 trees per year at a forecast 2020-2022 cost of $1.388 billion.[72] This is an order of magnitude larger in scope than SCE's program. The primary cost of the EVM program for PG&E appears to be the assessment and removal of hazard trees, as shown in Table 3 above.

In 2019, PG&E "remediated" 867,924 trees as part of the EVM, at a cost of $470 million. Of those trees, about 663,500 were assessed (presumably to determine whether they were hazard trees) with no additional work conducted.[73] PG&E trimmed almost 59,000 trees (both radial and overhang trim) and removed almost 97,000 trees as part of EVM.[74]

The major problem with the healthy tree removal programs is that there is inconclusive evidence that these healthy trees are responsible for blow-ins, fault, and ultimately ignitions. While SCE and PG&E have claimed that "healthy" trees are responsible for many vegetation-related contacts, TURN's review of the underlying data showed that less than 10% of the vegetation-caused ignitions were caused by healthy trees, for both PG&E and SCE; and that the number of healthy trees impacting power lines was less than 50 per year, out of several hundred tree-caused outages.[75] The utilities' proposals, and particularly PG&E's, to remove hundreds of thousands of trees to address the potential impact of tens of trees appears excessive.

Removing more trees than necessary may reduce ignition risks, but it is harmful if it results in re-deploying scarce tree trimming resources away from more effective vegetation management measures and imposing unnecessary cost burdens on ratepayers. Moreover, during extreme wind conditions, loose leaves and branches can blow into power lines from a considerable distance, and removing healthy trees does not address this threat of "blow-ins."

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[71] SCE DR WSD-002-095 and TURN 001-08f and g.
[72] PG&E 2020 WMP, Table 25. PG&E's amount for EVM greatly exceeds the forecast it provided in its 2020 GRC. In its GRC PG&E forecast about $180 million per year to remove about 140,000 trees per year.
[73] PG&E Response to DR TURN 010-02c.
[74] PG&E Response to DR TURN 007-09.
[75] TURN attaches portions of TURN's testimony regarding the PG&E (A.18-12-009) and SCE (A.18-09-002) hazard tree programs as Attachment 3 to these comments.

For example, the data demonstrate that palm fronds can travel large distances and contact power lines. Indeed, in Southern California loose palm fronds have been responsible for the vast majority of "tree contacts," despite being a minority of the trees. For example, in 2019 palms accounted for less than 6% of the trees near SCE's power lines, but caused 36% of the vegetation-caused interruptions.[76] Between 2015 and 2018 palms accounted for between 35% and 53% of all tree-caused interruptions annually. But removing other trees based purely on their "strike potential" (i.e. height greater than distance from power lines) does not address this problem. SCE needs to develop a more appropriate response plan to palm fronds, if possible, rather than removing numerous healthy trees near power lines that pose minimal risk of falling over.

Indeed, a similar problem apparently applies to blow-ins in PG&E's service territory. PG&E reduced its planned EVM mileage to 1,100 miles partly due to workforce constraints, but also due to concerns about efficacy:

> This reduction is due in part to a redeployment of certain vegetation management workers to focus on transmission assets in order to reduce the impact of PSPS events, workforce constraints, including a shortage of qualified pre-inspectors and line clearance tree trimmers, **and concerns about oversight and risk mitigation impact of the EVM program in reducing wildfires**. While EVM reduces wildfire risk from overhanging and adjacent fall-in trees, **during high wind events in 2019, PG&E found that trees and branches have blown into powerlines from further away than EVM typically treats.**[77]

The other major problem with healthy tree removal is that it diverts money and human resources from routine vegetation management, as the same contractors perform the different work. The utilities acknowledge there is a shortage of qualified trimmers. History suggests that a significant problem for PG&E was the lack of full compliance with existing tree clearance standards.[78]

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[76] SCE Response to WSD-002-102 and WSD-002-104. Palms comprised 5.6% of the trees in the inventory, and were sixth in prevalence behind oaks, pines and eucalyptus.

[77] PG&E Response to TURN DR 008-02. PG&E also explains that it has shifted some EVM work to transmission lines, rather than distribution lines. PG&E WMP, pp. 2-3 to 2-4.

[78] CALFIRE reports indicate that at least eleven of the eighteen 2017 northern California fires were caused by PG&E's violations of then-existing vegetation management standards, including the McCourtney, Lobo, Honey, Sulphur, Blue, Norrom, Partrick, Pythian, Adobe, Pocket, and Atlas Fires. See, CAL FIRE News Releases dated May 25, 2018, June 8, 2018, October 9, 2018, and January 24, 2019.

PG&E has explained in court filings that it cannot guarantee 100% compliance with clearance requirements in real time. While perhaps some instantaneous non-compliance is understandable, more routine trimming to greater clearances at time-of-trim could reduce some of the non-compliance.

If inadequate existing vegetation management practices are contributing to wildfire risk, then diverting resources into "enhanced" practices that include primarily healthy tree removal will likely make matters worse by neglecting routine tree trimming or other risk mitigation activities. TURN is concerned that the pace of trimming to 12-foot clearances in Tiers 2 and 3 may be hampered by additional tree removal work being conducted through the EVM program, which is targeting only a portion of HFTD circuits.[79] Moreover, as part of its EVM work in 2019, PG&E removed 96,781 trees, but conducted overhang trims on only 14,754 trees.[80] While TURN does not have data on the number and extent of potential overhanging limbs in Tier 2 and 3 areas, we are concerned that PG&E is spending too much effort on healthy tree removal, rather than focusing on trimming all trees in Tiers 2 and 3 to a 12-foot radial distance and clearing all overhangs to the sky.

In PG&E's General Rate Case and SCE's GS&RP Application, TURN proposed that a statewide study be conducted, with the benefit of outside experts, to evaluate the need and scope for hazard tree removal, especially as compared to alternatives of more extensive tree trimming or overhang trimming. The WSD should not authorize PG&E's and SCE's hazard tree removal programs as proposed. Rather, the WSD should direct the utilities, and especially PG&E, to:

- Require complete and transparent reporting of the number and percentage of trees trimmed to 12 feet,
- Require complete and transparent reporting of the number and percentage of overhangs removed in both HFTD and non-HFTD areas;
- Devote limited vegetation management contractor resources to trim all HFTD area trees to twelve feet, where possible;

[79] See, for example, PG&E 2020 WMP, p. 5-7. PG&E performed EVM on almost 2,500 miles of Tier 2 and 3 circuits in 2019, and plans to address 1,800 miles in 2020 at a cost of almost half a billion dollars.
[80] PG&E Response to TURN DR 013-01.

- Clear more overhangs in Tier 2 and 3 areas;
- Devise a more appropriate plan to address blowing palm fronds; and
- Coordinate a statewide study to determine the best practices for removing hazard trees and compare the efficacy of that program to other trimming alternatives.

4. The Utilities Should Accelerate the Use of LiDAR for Improving Tree Trimming and Removal

TURN is concerned that the utilities are not using LiDAR data to target trees for trimming or removal so as to improve the efficiency of vegetation management activities. In both its last WMP and its GRC, PG&E stated that it would use LiDAR to identify trees that may be dead or dying and to improve the effectiveness of its tree trimming and removal activities.[81] In its 2020 WMP, PG&E explains that in 2019 it captured LiDAR data for 25,200 circuit miles, consisting of most Tier 2 and 3 areas,[82] and that the goal for 2020 "is to leverage the remote sensing data already gathered to produce more advanced analytics to proactively identify distribution circuit spans or regions where the risk from encroaching vegetation is greatest."[83]

However, when TURN asked PG&E "to explain in detail how and when PG&E will use such [LiDAR] data, and how these data will inform the number of trees, costs and/or scheduling of activities for hazard tree removal and/or enhanced tree trimming," PG&E responded only that it currently has "no plans to perform LiDAR inspections for routine vegetation management or Enhanced Vegetation Management work."[84] TURN is concerned that PG&E's forecasts for hazard tree inspection and removal work do not reflect use of the LiDAR data to better target the work.

SCE has captured LiDAR data on only a portion of its distribution system, and apparently plans to capture LiDAR data in 2020, and evaluate whether it can be incorporated into vegetation management activities.[85]

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[81] PG&E 2019 WMP, p. 79.
[82] PG&E 2020 WMP, p. 5-188 and fn. 19.
[83] PG&E 2020 WMP, p. 5-163.
[84] PG&E Response to DR TURN 010-03(b).
[85] SCE Response to DR TURN 003-18.

The WSD should encourage PG&E and SCE to make better use of LiDAR, and to share findings regularly with parties and the Commission.

B. Grid Hardening

1. Covered Conductor Installation Needs to be Targeted to Circuits Providing Greatest Risk Reductions

The single largest proposed utility WMP expenditure is for the installation of covered conductor. PG&E intends to install approximately 1,060 miles of covered conductor in 2020-2022 at a cost of $1.630 billion;[86] while SCE intends to install at least 4,000 miles of covered conductor in 2020-2022 at a cost of $1.882 billion.[87]

TURN has reviewed utility covered conductor proposals in the PG&E 2020 rate case, the SCE 2018-2020 Grid Safety and Reliability Program case, and the SCE 2021 rate case. While TURN generally supports deploying and testing covered conductor as a mitigation measure, the WSD must not approve the scopes proposed by the utilities, as there is insufficient data to indicate that such widespread deployment will be beneficial. TURN has provided specific recommendations (to the extent they differ from the utility) regarding scope of covered conductor and cost per mile of deployment in those other proceedings.

Both SCE and PG&E have modeled the wildfire risk posed by each mile of its overhead infrastructure in HFTDs, and both utilities have found that a relatively small percentage of circuit miles contain the vast majority of wildfire risk. This is based on the presence of nearby structures, ignition and fire spread modeling, and other factors.[88] For example, PG&E found that hardening just 22% of its HFTD circuit miles (about 5,500 circuit miles) addresses 95% of the wildfire risk in its HFTD.[89] Similarly, SCE has found that approximately 13% of its HTFD circuit miles (about 2,161 circuit miles) represent almost 95% of the risk-consequence in its high

[86] PG&E WMP, Table 23, Initiative 17.1.
[87] SCE WMP, Table 23, Initiative 3.1.
[88] See, for example, SCE WMP Sec. 4.3.
[89] PG&E WMP, p. 5-274. See also, PG&E Response to DR TURN 009-04.

threat area.[90] SCE intends to target its vegetation management inspections to the highest consequence circuits, recognizing resource constraints.

Some may argue that any amount of risk mitigation is worthwhile at any cost; however, that perspective ignores practical resource constraints and the tremendous affordability pressures faced by ratepayers. Installing covered conductor takes significant resources. PG&E reduced its proposed covered conductor scope by 50% in its rate case based on the need to deploy trained personnel to conduct asset repairs due to compliance failures discovered during the 2019 inspections. While TURN supported the initial (larger) scope of covered conductor, TURN did not oppose PG&E's amended cost forecast, which was incorporated in the settlement filed in A.18-12-009 on January 14, 2020. Installation of covered conductor, one of the highest cost per mile mitigations, on very low-risk circuits may not be the best use of ratepayer funds.

For example, while covered conductor appears to address the significant risks of vegetation contact, there is the significant possibility that on certain circuits the use of greater tree trimming clearances may be sufficient to mitigate risk cost-effectively. There are also new technologies that the utilities are testing that may mitigate the occurrence of faults and ignitions by rapid de-energization, even in the case of vegetation contact. The WSD should thus require the utilities to continue collecting all data necessary to evaluate the effectiveness of covered conductor, the effectiveness of alternative technologies, and to improve their risk analyses so as to properly evaluate the desired scope of covered conductor deployment.

2. Pole Replacement

PG&E and SCE had considered replacing all wood poles with fire-resistant composite poles as part of grid hardening, and such replacement may be embedded in grid hardening forecasts. However, the utilities conducted experiments in 2019 that demonstrated that wood poles wrapped with fire retardant materials worked just as well as steel and composite poles.[91] Wrapping existing wood poles is much more cost-effective than replacing a pole with a non-wood pole, unless the pole replacement is necessary for other reasons. TURN commends the

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[90] SCE Response to DR WSD-002-84 (UVM-07, p. 6).
[91] See, for example, PG&E WMP, pp. 5-120 and 5-141; SCE WMP, pp. 5-4 and 5-57.

utilities for working together to conduct actual tests to determine optimal strategies for pole replacement.

3. Fault Indicators

All ignitions are associated with faults, and locating faults expeditiously has always been an important reliability tool. The utilities have installed fault indicators to help troublemen locate faults, as the traditional fault indicators emit a light that can be visually observed.[92] PG&E has approximately 20,000 fault indicators, with about 4,300 in Tiers 2 and 3. SCE has almost 12,000 fault indicators, with about 2,900 in Tiers 2 and 3.

Apparently, SCE has installed a significant number of "remote fault indicators" (RFIs), which communicate a signal to the distribution operation control center that allows for more rapid identification of the fault location. About 20% of SCE's fault indicators in its service territory, and about 12% in Tiers 2 and 3, are RFIs.[93] In contrast, only about 2% of PG&E's fault indicators are RFIs.[94] PG&E indicates it is testing the line sensor technology used by RFIs to "proactively monitor and locate distribution grid disturbances."[95]

TURN has supported RFI installation as a reliability improvement technology. TURN does not have sufficient information to evaluate whether RFIs can be useful in detecting and mitigating faults that could cause ignitions, though the text of the WMPs indicates that line sensor data could be useful for monitoring grid problems. While TURN has not had the opportunity to fully research the history of utility research and use of sensors, including remote fault indicators, we are concerned that this may be another area where there should be greater cooperation and communication among the California utilities. While ratepayers fund hundreds of millions of dollars for research and development through EPIC and IOU programs, it is sometimes disheartening to see a lack of parity and/or cooperation in testing and developing technologies.

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[92] The number of fault indicators present on utility systems is shown in Table 15 of the WMPs.
[93] SCE Response to DR TURN 001-02.
[94] PG&E Response to DR TURN 007-02.
[95] PG&E WMP p. 5-95.

C. The Utilities Should Cooperate to Investigate the Use of Emerging Technologies

The previous observation concerning sensors and RFIs applies to the various other emerging technologies. The utilities describe several emerging technologies that have the potential to mitigate ignitions by rapidly de-energizing power lines after a fault condition.[96] TURN has not evaluated the technical merits of these potential mitigation strategies. However, TURN was concerned that the utilities are each conducting separate small pilots and EPIC programs, and moving somewhat cautiously on field deployment. TURN suggests that the scale of the wildfire problem demands a change from the traditional utility-specific research and demonstration projects. The utilities should coordinate and emphasize the potential development of technologies that could reduce or eliminate ignition risk without requiring billions of dollars in covered conductor deployment. The WSD should create a process to expedite utility developments in this area.

VI. Conclusion

The Legislature has mandated a very rapid timeline for reviewing the utility Wildfire Mitigation Plans. TURN recommends that the WSD focus on providing substantive input to the utilities for improving the design of the various mitigation programs; but TURN cautions that the WSD should make clear that if it "approves" the plans, it in no way blesses the scope proposed by PG&E or SCE, or approves the self-classification of certain existing programs as new wildfire mitigation programs.

TURN further recommends that WSD require certain reporting and modifications to utility proposals for enhanced vegetation management and grid hardening, as described in these comments.

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[96] See, for example, PG&E WMP Sec. 5.1.D, and especially the discussion concerning the REFCL and the DTS-FAST technologies. See, also, SCE WMP Sec. 5.3.3.2.3 re. the REFCL.

ATTACHMENTS

1. TURN Letter Comments on PG&E RAMP Methodology
2. TURN Comments and Reply Comments Concerning Metrics in R.18-10-007
3. A.18-09-002, TURN Borden Testimony, pp. 23-27

   A.18-12-009, TURN Borden Testimony, pp. 11-16

4. A.18-09-002, Exh. PG&E-18v1, Table 2A-2

ATTACHMENT 1

TURN Comments on PG&E RAMP Methodology

TURN
THE UTILITY REFORM NETWORK

785 Market Street, Suite 1400
San Francisco, CA 94103
415-929-8876 • www.turn.org
Thomas J. Long, Legal Director

February 19, 2020

Ms. Tessa Carlberg
and PG&E 2020 RAMP Team
(via email)

Re: TURN Concerns with PG&E's Methodology for Risk and Mitigation Assessment

Dear Ms. Carlberg:

I write to share TURN's concerns regarding the methodology that PG&E plans to use for its 2020 Risk Assessment and Mitigation Phase (RAMP) submission later this year. These concerns are based on the information that PG&E provided at workshops held on January 13, 2020 and February 4, 2020.

As you know, PG&E's 2020 RAMP submission will be the first RAMP that is required to follow the methodology prescribed by Decision 18-12-014, which adopted a Settlement Agreement that constitutes "the minimum required elements for risk and mitigation analysis in the Risk Assessment and Mitigation Phase (RAMP) and General Rate Case."[1] Decision 18-12-014 was a culmination of more than three years of effort by the Commission, IOUs, and intervenors that involved a tremendous amount of effort by the stakeholders. TURN, the lead intervenor in that proceeding, devoted over 3,000 attorney and expert hours to the process which included numerous pleadings, workshops, working group meetings, and test drive analysis.[2] It is extremely important that the Settlement be implemented faithfully because the methodology adopted in that Settlement will help to ensure that ratepayer funds are directed to the most needed and most cost-effective safety work, which is essential to achieving the goal of safe utility operations.

As will be described in this letter, many of TURN's concerns go to the heart of the methodology prescribed by the Settlement. In TURN's view, if these problems are not fixed, PG&E's leaders

[1] D.18-12-014, p. 2.
[2] D.19-09-050, p. 14. (Granting intervenor compensation to TURN)

and the Commission will not be provided with correct information regarding the most important safety risks facing PG&E and the most cost-effective mitigation measures for those risks.

<u>Concerns with PG&E's Multi-Attribute Value Function (MAVF)</u>

As stated in the Settlement, the MAVF is a tool for combining in one measure all of the potential consequences of the occurrence of a risk event. It is fundamental to accurately and comprehensively capturing all of the pre- and post- mitigation consequences of risk events and thus must be well-designed in order to yield reliable calculations of the risk reduction benefits of mitigation measures under consideration.

Here are TURN's concerns based on what we've seen to date.

1. The scaling functions used in PG&E's MAVF to convert attribute levels in natural units to scaled units, which are then weighted and added to determine the consequence of risk event ("CoRE") scores, have the following features that prevent the correct computation of CoRE values:

    a. The scaling function for the attribute "financial consequences" is nonlinear. This nonlinear scaling function violates a simple concept: the value of one dollar is always one dollar. It also violates the idea that financial benefits should be additive; in other words, it permits the financial value of a single project to change if that project is divided arbitrarily into two or more parts. PG&E's financial scaling function should be linear.

    b. The scaling function for the safety attribute indicates that the value of reducing equivalent deaths from 1 to zero is less than one-tenth as much as reducing the equivalent deaths from 100 to 99. This is both counterintuitive and inconsistent with industry-wide practice, which typically values the complete avoidance of deaths from utility-related operations most highly. We illustrate the issue with two different, but similar, risk reduction examples. (1) Suppose that there are two different risk events, such that one is limited in scope and is expected to result in few equivalent deaths, perhaps approximately one, and the other is a catastrophic event that is expected to result in many equivalent deaths, perhaps close to 100. Suppose that the consequences of each risk event can be mitigated by an action that reduces the expected number of equivalent deaths by exactly one in both cases. PG&E's scaling function implies that it is more valuable to reduce the risk of the catastrophic event by one equivalent death than it is to reduce the risk of the non-catastrophic event by one equivalent death, perhaps resulting in zero expected deaths for the non-catastrophic event. (2) Further, suppose that the catastrophic event is about ten times less likely to occur than the non-catastrophic event (or that the annual frequency of the catastrophic event is one-tenth the annual frequency of the non-catastrophic event). PG&E's scaling function implies that it is more valuable to apply the risk mitigation to a single catastrophic event than it is to apply it to ten non-catastrophic events. Notice that if the frequency of the catastrophic event were one per year and the frequency of the non-catastrophic event were ten per year, then PGE's scaling function implies that it is more valuable to save one life associated with the catastrophic event than ten lives associated with the non-catastrophic event. None of these implications is persuasive. The nonlinear scaling function should be modified.

c. The implied statistical value of life given by the weights and the attribute ranges for safety and financial impacts is $100 million. This is ten times larger than the statistical value of life estimates that have been used by the U.S. Environmental Protection Agency to evaluate health risks and the U.S. Dept. of Transportation to evaluate vehicle safety features. PG&E's much higher value may result in skewing the ranking of different risks and misallocating ratepayer dollars away from more cost-effective risk management activities.

2. There appear to be too few attributes. Under the Settlement, a utility should select attributes that "… cover the reasons a utility would undertake risk mitigation activities." In other words, a utility should select a set of attributes that reflect all of the reasons for undertaking risk mitigation activities. PG&E's MAVF includes only four attributes: Safety, Electric Reliability, Gas Reliability, and Financial. TURN strongly doubts that these attributes cover all of the reasons for engaging in risk mitigation. For example, PG&E surely takes into account impact on customer satisfaction in deciding on mitigation measures. Yet, these attributes are not accounted for in PG&E's MAVF. (PG&E cannot reasonably claim that it has no way of measuring customer satisfaction since, in the Bankruptcy docket (I.19-09-016), PG&E has proposed using results of a customer satisfaction survey as a metric for awarding incentive compensation to PG&E executives.) By failing to include a customer satisfaction attribute, PG&E risks ignoring the adverse impacts of Planned Shutoffs (what PG&E calls PSPS events) on customer satisfaction in assessing the consequences of implementing Planned Shutoffs. More generally, the fact that PG&E's Safety and Financial attributes, their ranges, and their relative weights imply a statistical value of life ten times larger than the values used by

U.S. government agencies suggests PG&E implicitly is including one or more other attributes in its MAVF, but has failed to identify these attributes and make them explicit.

3. PG&E claims that one motivation for nonlinear scaling functions is "risk aversion." This claim is inconsistent with long-standing economic principles. If an individual is risk averse, it simply means she will not accept a fair bet. For example, suppose an individual is offered a game involving a coin flip. If the coin lands on "heads" she wins $100. If it lands on "tails," she wins nothing. The expected winnings are $50. But if the individual is risk averse, she will only be willing to pay some amount less than $50 to play the game. The more risk averse she is, the less she will be willing to pay. However, risk averse behavior in the face of uncertainty doesn't apply with multi-attribute scaling functions because the purpose of scaling functions is to reflect <u>known</u> tradeoffs. For example, PG&E's Safety attribute scaling function values a reduction in deaths from 100 to 99 more than ten times greater than reducing deaths from one to zero. In other words, if PG&E knew with certainty that a risk mitigation measure would reduce the deaths from an incident by one, from 100 to 99, the company would value that reduction more than ten times greater than a risk mitigation measure the company knew with certainty would reduce deaths from another incident from one to zero. The difference in the value PG&E placed on a reduction of one death from a risk event has nothing to do with uncertainty or risk aversion. Rather it just reflects PG&E's preference for reductions in worst-case outcomes over <u>equivalent</u> reductions in other, non-worst-case outcomes. (This is another reason why the Financial attribute scaling function should be linear: the value of reducing a loss by one dollar from $100 to $99 should be exactly the same as the value of reducing a loss by one dollar from $10 to $9, and so forth.) TURN and its consultants would be happy to meet with PG&E to discuss appropriate ways to address uncertainty or risk-aversion that are consistent with the Settlement.

4. PG&E stated in its January 13, 2020 workshop that another motivation for the nonlinear scaling functions selected was that the company did not like the initial results of its modeling, and so adjusted the scaling functions to reflect company intuition regarding the levels of different risks. In effect, TURN believes that PG&E admitted to "putting its thumb on the scale" when ranking different risks, which is not consistent with the spirit of the Settlement. Of most concern is that, by doing so, PG&E may not, in fact, select the most cost-effective set of risk mitigation measures and thus will not serve its ratepayers, who will be asked to pay for those measures.

Concerns with the Calculation of Risk Spend Efficiency (RSE)

Risk Spend Efficiency (RSE), which is risk reduction divided by cost, is the key end result of the analysis of risk mitigation measures. It is the calculation that reflects the cost-effectiveness of competing mitigations. The Settlement (Row 25) requires that the numerator and denominator be present values to ensure the use of comparable measurements of benefits and costs. TURN has the following concern with PG&E's method of calculating RSE.

5. On page 20 of its January 13, 2020 workshop slides, PG&E states that it is using three different discount rates to evaluate risk management costs and benefits: a zero discount rate for the Safety and Reliability attributes, a market-based discount rate for the Financial attribute (which PG&E stated was 3.0%), and PG&E's utility discount rate (i.e., the company's weighted average cost of capital) for all program costs. This is incorrect and will result in biased RSE values. The discount rates used to compute the RSE values must be the same for both the numerator (i.e., the difference between pre- and post-mitigation risk) and the denominator (costs). Using different discount rates is inconsistent with basic economic concepts of project evaluation. For example, suppose a given project will cost PG&E $100,000 one year from now and also provide $100,000 worth of Safety benefits at that time. In that case, PG&E should be indifferent to undertaking the project, because the net benefit one year from now is exactly zero. But if, as PG&E stated in its MAVF workshop, the company applies a 0% discount rate to the benefits and a 7.7 % discount rate to the costs, then the present value benefits of this project are $100,000 and the present value costs are $92,851 ($100,000 / 1.077). Hence, even though the projects have identical benefits and costs one year from now, on a present value basis, on net, the present value benefits exceed the present value costs by $7,149. Creation of this phantom $7,149 benefit would artificially increase the RSE value, skewing the selection of a portfolio of risk management measures.

Failure to Account for All Consequences of Risk Events

Under the Settlement methodology, it is critical that all consequences of a risk event ("CoRE") be included in the analysis even if they require subject matter expert (SME) judgment to measure or estimate. In that regard, Row 31 of the Settlement states that SME judgment should be used if the methodology requires use of data that is not available. PG&E appears to not be adhering to this requirement:

6. PG&E ignores what it deems to be "indirect" impacts or consequences of the occurrence of a risk event. For example, PG&E excludes deaths or injuries caused by the failure of electrical equipment caused by a widespread planned or unplanned outage -- such as non-functioning traffic lights, breathing machines, and other medical equipment -- even though these are known consequences of outages. The exclusion of indirect impacts for reliability-related risk events, such as a blackout, means that CoRE values will be underestimated.[3] In addition, RSE values will also be inaccurate, such as from the failure to consider adverse safety impacts from Planned Shutoffs. PG&E should include these known impacts in its CoRE calculations. At the February 4, 2020 workshop, PG&E stated that it excluded so-called indirect impacts from some risk events because the company lacked data with which to estimate such impacts. However, an absence of data does not mean the effects are zero. Moreover, PG&E has subject matter experts who should be able to develop estimates of these indirect impacts. It can also intensify its efforts to seek out data about the safety impacts of power outages.

7. The same exclusion of safety impacts from outages also affects the risk that PG&E calls "Third-Party Incident." One way to correct this is to distinguish between outage-related and non-outage-related outcomes on the right side of the bowtie, and include potential safety consequences associated with the outage outcomes.

<u>Insufficient Granularity of Analysis</u>

The Settlement requires that risk analysis be broken down by "tranches" of assets (or systems) with like characteristics for purposes of risk assessment (Settlement, definition of "tranche"). This is a key provision of the Settlement to make sure that the truly highest risks in the system, which may be geographically localized or focused on a small subset of an asset group, get the requisite attention. Likewise, this granularity requirement ensure that mitigation efforts are focused on where they are most needed and money is not wasted because a mitigation program is too broadly scoped. Following are some of the concerns we have regarding insufficient granularity.

8. For the "Wildfire" risk, PG&E should have more granularity. Specifically, PG&E should have tranches that reflect, at the least, the following distinguishing characteristics which

[3] The exclusion of safety impacts from power outages raises the question of whether fixing this problem would move the System Wide Blackout risk higher in PG&E's scoring and ranking so that it should be included in the RAMP.

are necessary to ensure that the assets or systems have like characteristics for risk assessment purposes:

a. More granularity is needed for asset condition, e.g., overhead distribution and transmission lines. Appropriate granularity will focus where maintenance and replacement work is needed.
b. As one particular aspect of asset condition, the tranches should reflect whether the asset has been upgraded, e.g., whether covered conductor has been installed for distribution circuits. An overhead line with covered conductor should have much different risk characteristics than one without.
c. More granularity is needed for geographic locations with different risk characteristics. For example, PG&E undoubtedly knows that particular locations within HFTDs are more susceptible to fire weather conditions or high fuel content than other HFTD areas.

9. In developing tranches of assets, PG&E should account for differences in consequences of the occurrence of risk events owing to geographic location of the assets. For example, the CoRE values for "Gas Transmission Pipeline LOC" risk will depend on geographic location: LOC events in urban locations are likely to have more severe consequences than events in rural locations. Disaggregating tranches will lead to more accurate RSE estimates and more cost-effective risk management programs. Similarly, PG&E has in its GRC said that gas distribution system cross bores in San Francisco have relatively higher risk levels than cross bores in other areas because of the relatively high consequences of cross bore related incidents in the densely populated city. By failing to use separate geographic-based tranches for the cross-bore risk, higher risks may be masked in the Risk Selection process, and the resulting RSE values are likely to be insufficiently granular.

10. PG&E should incorporate asset condition when it specifies tranches of assets involved in specific risks. An example is the "Gas Transmission Pipeline Loss of Containment (LOC)" risk, such as what occurred in San Bruno. It is reasonable to believe that LoRE depends on the condition of the pipeline, which varies based on many characteristics, such as type of weld, date of manufacture, seamless or not, etc. Accounting for differences in condition will allow PG&E to develop more accurate RSE values and thus develop more cost-effective risk management programs.

Incorrect Baseline for Risk Analysis

Using the correct baseline for the risk analysis is necessary to ensure that PG&E is not double counting risk reduction benefits that are supposed to be achieved by currently funded mitigation programs.

11. As required by Rows 10 and 11 of the Settlement, the baseline for the 1/21/20 Risk Selection document should have been 2022, not 2019, in order to capture the effects of risk mitigation benefits expected to be achieved prior to the next GRC period. Although PG&E says it will not have this same problem with the analysis it will be performing of the selected RAMP risks, the fact remains that the scoring of PG&E's risks for the February 4, 2020 Risk Selection workshop is not consistent with the requirements of the Settlement and may have resulted in the incorrect ranking and selection of risks for RAMP.

PG&E's Intentions Regarding Calculation of Risk Reduction for "Controls"

12. PG&E indicated at the January 13, 2020 workshop that it may not calculate RSEs for "controls" – mitigations currently in place – in its upcoming RAMP submission. PG&E contended that it is difficult to estimate risk reduction for this category of mitigations in the available time. TURN views this position as inconsistent with the Settlement (Row 26), which requires RSE scores for all RAMP mitigations, without distinguishing between new or existing mitigations or whether mitigations are mandated. The claimed lack of "counterfactual" data is not a legitimate excuse because, as noted above, Row 31 of the Settlement states that SME judgment should be used if data are not available. It is important to be able to compare RSEs for existing and potential new mitigations in order to determine if some of the current mitigations should be discontinued. Notably, SED previously strongly recommended in PG&E's prior RAMP that, in future RAMP submissions, PG&E provide RSE calculations for "controls" on the same basis as for other mitigations.

Insufficient Transparency

13. To date, PG&E has not provided transparency in its calculations and inputs to those calculations. Transparency is required by Row 29 of the Settlement. In particular, TURN requires at least the following inputs and calculations to verify PG&E's risk selection and RSE analysis:

a. The probability distributions on the levels of all attributes in natural units as a consequence of the occurrence of the risk event;
b. The likelihood of occurrence of the risk event;
c. The likelihood of occurrence of each driver (left side of bowtie);
d. The conditional probability of the occurrence of the risk event, given the occurrence of the each driver (left side of bowtie);
e. Supporting details showing how the likelihood of a risk event ("LoRE") was calculated;
f. Supporting details that show how the CoRE was calculated (right side of bowtie).

Other Concerns and Recommendations

13. TURN is concerned that PG&E has not reflected any cyber-related risks in its Preliminary Risk Selection. TURN recommends that PG&E consider whether cyber events should be viewed as a separate risk event, a risk category, or a driver of other risk events.

14. TURN is concerned that PG&E has not included "Inadequate and/or Inaccurate Recordkeeping" as potential drivers of many risk events, including the "Gas Distribution Pipeline LOC" and "Gas Transmission Pipeline LOC" risks. As you know, record-keeping failures were key contributing factors to the San Bruno transmission pipeline explosion and several incidents on PG&E's gas distribution system. If these drivers are not included, then PG&E is likely to underestimate LoRE values. TURN believes that the only valid reason for excluding inadequate and inaccurate recordkeeping as drivers would be if PG&E believes and publicly states that the company has completely addressed and remedied its past record-keeping problems, so that they are no longer drivers of risk events.

15. For the "Wildfire" risk, TURN recommends that PG&E include, as a driver, wind speed, or some specification of weather conditions. For clarity, TURN also recommends that PG&E use Fire Weather *Conditions* instead of *Warning* in the outcomes (right side of the bowtie).

Conclusion

We have identified numerous concerns with the methodology PG&E is using. Many of these implicate the validity of the analysis that PG&E used for the Risk Selection phase that was the subject of the February 4, 2020 workshop. In our view, because PG&E made methodological choices that are contrary to the requirements of the Settlement, the risk scores that support PG&E's risk selection are incorrect and may have led to the incorrect selection of risks. However, because of the transparency problem identified above, we are unable to assess the calculational impacts of the concerns discussed in this letter.

This situation may have been avoided had PG&E consulted with TURN in the development of its RAMP methodology prior to the February 4, 2020 workshop. However, instead of treating TURN as a partner by virtue of the Settlement, PG&E made its methodological choices without consulting with TURN, despite the demonstrated, huge commitment that TURN has made over the years to getting California's large utilities to implement a sound approach for assessing risks and comparing the cost-effectiveness of risk mitigations.

Now that you have, albeit belatedly, given us an opportunity to provide our feedback, we urge PG&E to correct the problems identified in this letter as soon as possible.

Sincerely,

/s/
Thomas J. Long
Legal Director

Cc: Steven Haine, SED
Service Lists for A.15-05-002, I.17-11-003, and A.18-12-009

ATTACHMENT 2

TURN Comments and Reply Comments Concerning Metrics in R.18-10-007

FILED
11/06/19
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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	Rulemaking 18-10-007 (Filed October 25, 2018)

COMMENTS OF THE UTILITY REFORM NETWORK

ON WORKSHOPS IN PHASE 2

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Thomas J. Long, Legal Director
Eric Borden, Energy Analyst

THE UTILITY REFORM NETWORK
785 Market Street, Suite 1400
San Francisco, CA 94103
(415) 929-8876 (office)
TLong@turn.org

November 6, 2019

TABLE OF CONTENTS

COMMENTS OF THE UTILITY REFORM NETWORK ON WORKSHOPS IN PHASE 2

I. INTRODUCTION AND SUMMARY

The Utility Reform Network (TURN) submits these opening comments on the issues presented in the October 10, 2019 Administrative Law Judge's Ruling Requesting Comments on Workshops in Phase 2 (ALJ Ruling).

In these comments, TURN recommends:

(1) Adoption of TURN's proposed metrics to assess the overall effectiveness of WMPs and the effectiveness of individual mitigations, as described in Section II;

(2) Engaging independent evaluators as soon as possible – before a decision in this Phase -- to assess the quality and adequacy of their wildfire risk mitigation work, as described in Section III; and

(3) Implementing the process for review of future wildfire mitigation plans (WMPs) described in Section IV.

II. TURN'S PROPOSED METRICS

TURN appreciates the discussion and input from the September 18, 2019 workshop on metrics, which provided greater context and input to this important topic. The workshop and comments are intended to "result in a list of metrics that provides the Commission, the Department of Forestry and Fire Protection (CAL FIRE), related agencies and researchers tools to evaluate the effectiveness of the WMPs at mitigating catastrophic wildfires."[1] With this goal in mind and with the benefit of the workshop discussion and further reflection, TURN provides its updated recommendations for metrics to ensure the Commission and parties can assess the effectiveness of utility WMPs on an overall basis and at a more granular level focused on the effectiveness of particular mitigation measures. TURN's support for specific metrics here should not be construed as signifying that other proposed metrics and data are not informative, valuable, and necessary to understand the effectiveness of certain mitigations. However, the Commission

[1] D. 19-05-036 ("Guidance Decision"), OP 4, p. 42.

must focus on those metrics that will provide the most accurate understanding of the effectiveness of utility WMPs.

There are three broad categories of metrics that should be established to understand the effectiveness of utility WMPs. The first is those that measure the *overall* plan's effectiveness. This was the primary focus of most parties' initial proposals. The second category should capture the effectiveness of *individual* mitigations on reducing wildfire risk. As the Commission stated, "there must be a way to connect [each] mitigation measure with the outcome to evaluate the efficacy of the measure."[2] Lastly, special consideration must be given to planned power shutoffs (PSPS) when assessing both overall and individual mitigation WMP effectiveness. TURN's proposals regarding these categories of metrics are discussed in the ensuing sections.

A. Metrics to Assess Overall WMP Effectiveness[3]

Regarding the first category, overall WMP success, TURN proposes the following metrics be adopted, based primarily on previously presented party proposals. TURN recommends some adjustments to the calculation of these proposed metrics to ensure they are normalized for three elements- wildfire-prone weather (e.g. FPI), time (days of such weather), and utility area (miles of overhead conductor in HFTD). This normalization allows the metrics to be tracked over time and compared to other utilities, which is necessary to understand and compare the effectiveness of utility WMPs.

Table 1. TURN Supported Metrics to Assess Overall Effectiveness of WMPs

Original Proponent	Original Proposed Metric	TURN's Recommended Modified Metric	Comments
SDG&E	Equipment caused ignitions in HFTD, when the FPI is rated as Elevated or higher	Equipment caused ignitions in HFTD, when the FPI is rated as Elevated or higher, divided by the number of FPI days and utility HFTD overhead circuit miles	TURN's modifications normalize for duration of FPI conditions and overhead circuit miles.

[2] D.19-05-037, p. 48.
[3] Sections II.A, II.B, and II.C respond to Question 7 in the ALJ Ruling.

SDG&E	Overhead faults on circuits in HFTD, when the FPI is rated as Elevated or higher	Overhead faults on circuits in HFTD, when the FPI is rated as Elevated or higher, divided by the number of FPI days and utility HFTD overhead circuit miles	Same comment.
SDG&E	Energized wire down events within HFTD, when the FPI is rated as Elevated or higher	Energized wire down events within HFTD, when the FPI is rated as Elevated or higher, divided by the number of FPI days and utility HFTD overhead circuit miles	Same comment.
SDG&E	Vegetation caused outages in HFTD, when FPI is rated as Elevated or higher	Vegetation caused outages in HFTD, when FPI is rated as Elevated or higher, divided by the number of FPI days and utility HFTD overhead circuit miles	Same comment.
SDG&E	Vegetation caused ignitions in HFTD, when the FPI is rated as Elevated or higher	Vegetation caused ignitions in HFTD, when the FPI is rated as Elevated or higher, divided by the number of FPI days and utility HFTD overhead circuit miles	Same comment.
PG&E	Number of other/animal caused outages in HFTD areas	Number of other/animal caused outages in HFTD areas when the FPI is rated as elevated or higher, divided by the number of FPI days and utility HFTD overhead circuit miles	Same comment, plus add limitation to outages when FPI is Elevated.
PG&E	Number of other/animal caused ignitions in HFTD areas	Number of other/animal caused ignitions in	Same comment as previous row.

		HFTD areas when the FPI is rated as elevated or higher, divided by the number of FPI days and utility HFTD overhead circuit miles.	
TURN	N/A	Number of wildfires greater than or equal to 10 acres where expected or found cause is utility equipment, divided by number of wildfires by FPI days	This is a clear metric of overall success, and also helps to measure situational awareness effectiveness.
TURN	N/A	Number of structures destroyed by utility-caused wildfire per FPI day	Same comment as previous row.

B. Metrics to Assess Effectiveness of Individual Mitigation Measures

In addition to metrics that track the overall success of utility WMPs, utilities must assess the effectiveness of the individual mitigation measures deployed that, ostensibly, drive these overall statistics. Understanding the contribution of individual measures to overall results will allow the utilities, stakeholders, and the Commission to optimize WMPs through appropriate balancing of various mitigation measures and avoiding overlap of duplicative measures. Ultimately, this information will also inform utility risk analyses, particularly the expected risk reduction of a given measure, such that expenditures can mitigate the most amount of wildfire safety risk at least cost to ratepayers.

A primary way to assess individual mitigation measures is to track ignitions and outages for the miles or segments of utility infrastructure where a mitigation measure has been deployed, compared with areas where it has not. The areas should be roughly similar to ensure comparability. This is similar to a "randomized control trial," in which a "treatment" and "control" group are contrasted to understand the effect of a specific intervention.[4] TURN

[4] See, for instance, https://himmelfarb.gwu.edu/tutorials/studydesign101/rcts.cfm. In addition, as discussed in the next section, the "treatment" and "control" groups should not include days when circuits were de-energized.

believes many of the metrics listed above in Table 1 regarding ignitions and outages can be utilized to investigate the effectiveness of individual mitigation measures, where applicable. Specific investigations should also be accomplished for cases when an ignition occurs despite the use of a relevant mitigation measure, in order to understand the limitations of various solutions and create best practices for implementation. This latter type of data collection may be particularly relevant for mitigations that are so widely deployed that a reasonable comparison to a "control" group is not possible. TURN does not know whether the latter applies to any mitigation measures for metrics and data to be collected in 2020. TURN provides several examples in Table 2 below, though this list is not meant to be exhaustive.

Table 2. Metrics to Assess Effectiveness of Individual Mitigations in Utility WMPs

Individual Mitigation	Ignitions Metric	Outages and Energized Wire Down Metrics
Effectiveness of Covered Conductor (CC)	Number of ignitions (broken out by cause) / FPI day / mile, with CC vs. without	Number of outages and wire down / FPI day / mile, with CC vs. without
Effectiveness of Enhanced Overhead Inspections and Remediations (EOI)	Number of equipment-related ignitions / FPI day / mile where EOI inspections occurred vs. without	Number of outages and wire down / FPI day / mile where EOI inspections occurred vs. without
Effectiveness of Fusing Mitigation	Number of ignitions / FPI day / mile where fuses have been deployed vs. without	Number of energized wire down / FPI day / mile lines where fuses have been deployed vs. without

Effectiveness of Enhanced Vegetation Management (EVM)	Number of vegetation ignitions / FPI day / mile where EVM meets WMP requirement[5] vs. without	Number of vegetation-caused outages / FPI day / mile where EVM meets WMP requirement vs. without

C. The Influence of Power Shutoffs on Plan and Mitigation Effectiveness Must Be Accounted For

Power shutoffs conducted to prevent utility equipment from igniting wildfires under dry, windy conditions represent a challenge to the calculation of metrics. First, the overall effectiveness of utility WMPs must be contextualized for the degree to which it was PSPS events rather than utility mitigations that reduce ignitions and/or wildfires. Second, these events may "mask" the performance of mitigation technologies when lines are de-energized, potentially when mitigations would be expected to limit the risk of ignition. TURN initially recommends an assessment of the following to help disentangle the role PSPS events played over a given period:

- Approximate number of ignitions prevented by PSPS events, with detailed summaries underlying this assessment available by request;
- For each PSPS, mitigations that were deployed on the de-energized circuit miles;
- An explanation of why deployed mitigations, if any, were deemed insufficient to mitigate the risk of wildfire under the conditions experienced for the PSP

Moreover, as noted in the previous section, metrics and data designed to isolate the effectiveness of individual mitigations should be careful to exclude results from events when circuits were de-energized, as power shutoffs mask assessment of the risk reduction benefits of other mitigation measures.

TURN looks forward to further stakeholder input on the topic of metrics that account for the use of de-energization to prevent wildfires.

D. Other Metrics-Related Issues

Response to Question 12: For purposes of calculating metrics that are comparable among utilities, the Fire Potential Indices (FPI) should be the same across the utilities. If utilities

[5] This should be separated by EVM program – e.g. side clearance, overhead clearance, risky tree species program, etc.

contend that they need individualized measures of FPI, they should have a high burden to demonstrate that the benefits of individualized FPI outweigh the considerable benefits of having comparable measures for metrics.

Response to Question 13: For purposes of ensuring comparability of metrics across utilities, it would be good to have some independent verification that each utility is using the same methodology to calculate FPI.

Response to Question 14: Consulting with a Working Group (WG) similar to the S-MAP metrics working group would be useful if Commission staff is considering the proposal of modified or new metrics. However, based on TURN's experience in the S-MAP working group, TURN believes working group meetings should be limited in number and that the most useful work is accomplished through the submission of written comments.

Thus, for example, a CPUC staff proposal for modified or new metrics could be shared with the WG in advance of a meeting, then discussed in a meeting, then made the subject of informal written comments by the WG members to the CPUC Staff. Based on those comments, the Commission staff could finalize its proposal, which could be released for formal comment by an ALJ Ruling. Those comments would then form the record for the Commission's decision on the Staff proposal.

III. INDEPENDENT EVALUATOR ISSUES

A. The Primary Focus of the Independent Evaluators Should Be to Assess the Quality and Adequacy of the Utilities' Risk Mitigation Work[6]

In light of the continuing grave threats posed by utility-caused wildfires, the primary focus of the Independent Evaluator efforts should be to assess the quality and adequacy of the mitigation measures implemented by the utilities.[7] Quality means whether the mitigation work -- such as transmission and distribution system inspections and vegetation management -- is being done right. Adequacy means whether the utilities' mitigation measures are sufficient and correctly targeted to address the highest risks. The near-term priority should be on quality assessments, particularly of utility inspections of transmission lines. Making sure transmission

[6] This section and the next section respond to Question 28 in the ALJ Ruling.
[7] As discussed below, TURN fully supports the list of tasks for the Independent Evaluator set forth in the *Assigned Commissioner and Administrative Law Judge's Ruling Launching Phase 2 of the Wildfire Mitigation Plan Proceeding*, June 14, 2019, pp. 8-9 (June 14, 2019 Ruling).

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	Rulemaking 18-10-007 (Filed October 25, 2018)

COMMENTS OF THE UTILITY REFORM NETWORK

ON THE DECEMBER 16, 2019 ADMINISTRATIVE LAW JUDGE'S RULING

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Thomas J. Long, Legal Director
Eric Borden, Staff Analyst

THE UTILITY REFORM NETWORK
785 Market Street, Suite 1400
San Francisco, CA 94103
(415) 929-8876 (office)
TLong@turn.org

January 7, 2020

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language should be changed to unequivocally require each of the large utilities to use the methodology adopted in D.18-12-014, with specific mention of that decision.

3. COMMENTS ON PROPOSED METRICS

As discussed in Sections 2.3 and 2.4 above, several of the proposed Metrics in Attachment 4 are vulnerable to utility puffery or manipulation of subjective assessments, and therefore of reduced usefulness as metrics -- though they may still provide useful information as long as the limitations are understood. The table in this section elaborates on these and other concerns, with the goal of providing constructive feedback on the Staff's thoughtful proposal.

CPUC Table / Metric Number / Name	TURN Comments / Recommendation	TURN Recommended Changes or Additional Metrics
	Progress Metrics	
Table 1 / 1 / Grid condition findings from inspection	1. As discussed in Section 2.3, this and several of the other Progress Metrics are only useful if the data reported by the utilities is subjected to rigorous field audits as necessary to provide confidence that the utility-provided data are accurate and the result of necessary and competent work by the utility. Utility reported data should be corrected based on audit results. Absent such audits, this and other Progress Metrics should be given reduced weight. 2. In addition, for this metric, Level 1, 2, and 3 findings should be broken out by distribution and transmission-level inspections for each priority level in addition to the total number of findings. Ensuring safe transmission facilities is particularly important in avoiding broad-scope PSPS events.	Separate out distribution and transmission-level findings (respectively) in HFTDs.
Table 1 / 3 / Extreme weather prediction accuracy	While the total percentage of PSPS predictions that are inaccurate provides a useful guide to utility prediction accuracy, TURN believes an additional metric would be helpful for understanding the potential impact of inaccurate utility weather predictions related to PSPS. In addition to the provided metric, TURN recommends the *number of customers* in each	Additional metric: *Number of customers subject to PSPS predictions that are false positives or false negatives 2 days before a potential PSPS event.*

	PSPS event subject to a false negative or positive prediction should be provided by each utility.	
Table 1 / 5 / Equipment operating above nameplate capacity	TURN is not aware of data that demonstrates that this metric correlates strongly with ignitions. At a minimum, TURN recommends it be focused on times of risky weather conditions (RFWs) as this represents when overloaded conditions would potentially lead to a catastrophic wildfire.	Number of circuit hours operated above nameplate capacity *during RFWs* in HFTD areas.
Table 1 / 6 / Risk spend efficiency of resources deployed towards wildfire mitigation efforts	1. As an initial matter, this item actually appears to consist of three separate measures which should be listed separately in a,b,c format. 2. A better name for these metrics would be "Cost-effectiveness of resources deployed . . ." as these are not true risk spend efficiency (RSE) calculations, which are defined as risk reduction divided by cost. Instead, these are specific and alternative means of assessing the cost-effectiveness of wildfire mitigation efforts. TURN supports efforts to assess cost-effectiveness of mitigations, but cautions that these metrics are likely to be highly dependent on the subjective judgment of utility personnel. If these are to have any value as metrics, the utilities must be required to "show their work" as discussed in Section 2.6 above. Even so, the results may be too subjective to warrant giving significant weight as metrics, as discussed in Section 2.4 above.	The name of this metric should be changed to "*Cost-effectiveness* of resources deployed towards wildfire mitigation efforts" and the three listed "units" should be treated as separate metrics, 6a, 6b, and 6c.
Table 1 / 7 / Extent of hardening across grid	The metric as proposed lacks clarity and could be potentially misleading. For example, the term "hardening" encompasses a wide variety of activities, as evidenced by the Glossary's broad definition of Grid Hardening, and the long list of Grid Hardening activities in Section 5.3.3 in Attachment 1. It is therefore highly unclear and hence subjective whether a grid asset is using "proven and demonstrated wildfire-resistant equipment." In addition, it is unclear whether the percentage intended to be calculated represents all assets, all miles of assets, or some other measurement. TURN recommends this metric be removed or sufficiently clarified to focus on	

	specific activities targeted by utilities for wildfire mitigation, with a clear definition for what should be used in the numerator and denominator of the percentage calculation.	
Table 1 / 8 / Community engagement activity and effectiveness	There are two separate metrics listed in the Table: (1) residents made aware of PSPS . . .; and (2) residents agreeing to participate . . .. Thus they should be listed separately.	Separate the two metrics into 8a and 8b.
Outcome Metrics - Leading, Utility-Sourced		
Table 2 / 1 / Near Misses	The Attachment 4 Glossary defines a "near miss" as "an event with significant probability of ignition. . .." As discussed in Section 2.4 above, this leaves a substantial degree of subjectivity for each utility to determine what a "significant probability of ignition" means. Such subjectivity creates the possibility that utilities can manipulate the reported data to show trends or other results that cast the utility in an unduly favorable light. In addition, to the extent this data reliably correlates with risk mitigation, it is most important to track "near misses" that have the highest potential consequences with respect to catastrophic wildfires – in high consequence weather conditions (RFWs) and areas (HFTDs). For example, data incorporating a fault that occurs during a rainstorm in a low wildfire threat area is uncorrelated with wildfire risk. Therefore, TURN recommends the Commission adopt "near miss" metrics that remove subjectivity by simply counting the number of events in each case (e.g. outages, faults), rather than relying on utility judgment of whether the event has a "significant probability of ignition." Further, the Commission should include additional metrics that track the highest potential consequence "near miss" events (during RFWs in HFTDs). These are provided in the column to the right.	Additional metrics: *Number of faults during RFW (total)* *Number of faults during RFW (normalized)* *Number of faults during RFW in HFTD (total)* *Number of faults during RFW in HFTD (normalized)* *Number of wire down events during RFW (total)* *Number of wire down events during RFW (normalized)* *Number of wire down events during RFW in HFTD (total)* *Number of wire down events during RFW in HFTD (normalized)*

Table 2 / 2 / Utility inspection findings	For the reasons discussed in Section 2.4 and with the immediately preceding metric, TURN recommends that the subjectivity of whether a finding "increase[s] the probability of ignition," be removed by simply providing a count of the average number of Level 1 findings. Further, the metric should assess relative progress in the highest consequence areas of a utility territory with respect to wildfire risks (HFTD).	Average number of Level 1/2/3 findings ~~that could increase the probability of ignition~~ discovered *in HFTDs*, per circuit mile per year.
Table 2 / 3 / Risk spend efficiency of WMP programs	1. As an initial matter, 3a and 3b appear to be identical metrics per the Unit column, differing only in name. TURN does not understand how "all WMP programs" (3a) differ from "wildfire-only WMP programs," as WMP programs should be wildfire-only. 2. More substantively, there is a disconnect between the name and the units. Similar to Table 1/#6, the described units are not true RSEs, but alternative measures of cost-effectiveness. However, these alternative measures leave out the consequence side of the risk equation, focusing only on the likelihood of ignition. Using a true average RSE across all WMP mitigations would be a better metric, as it would capture the full risk reduction benefits, including consequence reductions, from WMP mitigations. That said, to assess the usefulness of such RSE metrics, the utilities must be required to "show their work" in detail as discussed in Section 2.6 above. Furthermore, because the risk reduction calculations may be highly dependent on subjective judgment, the value of this calculation as a metric may be limited, although it would still be useful information.	Delete 3b, which appears duplicative. Replace the Unit description with: *Total risk reduction of all WMP programs divided by total cost of all programs, calculated in accordance with the settlement adopted in D.18-12-014*
Table 2 / 5 / Customer hours of PSPS based on stress test conditions	This proposed "metric" actually seems to require the use of a necessarily complex model. For example, the model would need values to reflect the extent of hardening of assets, ideally at a granular level. The results would only be useful if the model is well-specified and the inputs are reasonable, which would require significant analysis before a determination could be made that	

	the utility-reported results are accurate and useful. Rather than treating results of an opaque model as a "metric," which connotes a high level of reliability, this information could be required as a data submission under Attachment 1 or Attachment 5, to which the CPUC and WSD could give the appropriate weight based on their ability to assess the quality of the model and its inputs. In the long term, the CPUC/WSD should specify the model and require that all utilities use the same model, to allow for comparability of results.	
Outcome Metrics – Lagging, Utility-Sourced		
Table 2 / 6 / Customer hours of PSPS and other outages	In addition to the recommendations for each sub-part provided in the rows below, TURN recommends incorporating metrics that allow the Commission and parties to easily understand the degree to which PSPS is utilized by each utility in high consequence areas (HFTDs) and weather (RFWs). This will help inform the degree to which a utility is relying on PSPS to prevent ignitions during risky conditions.	Additional metrics: *Customer hours of PSPS during RFW (total)* *Customer hours of PSPS during RFW (normalized)* *Customer hours of PSPS during RFW in HFTD (total)* *Customer hours of PSPS during RFW in HFTD (normalized)* *Customer hours of PSPS during RFW / Total RFW Hours (total percentage)*
Table 2 / 6a / Customer hours of planned outages including PSPS (total)	It is unclear why metrics that are supposed to focus on prevention of wildfires should be concerned with planned outages that are unrelated to wildfires. This metric should be revised to focus on PSPS events, as many "planned outages" are unrelated to wildfire mitigation efforts.	Customer hours of ~~planned outages including~~ PSPS (total)
Table 2 / 6b / Customer hours of planned outages including PSPS (normalized)	See previous comment.	Customer hours of ~~planned outages including~~ PSPS (normalized)

Table 2 / 6c / Customer hours of unplanned outages, not including PSPS (total)	Unplanned outages that are unrelated to wildfires, such as outages caused by winter storms, are not relevant to preventing wildfires. TURN recommends this metric be modified to focus on outages resulting from wildfires.	Customer hours of unplanned outages *resulting from wildfires*, not including PSPS (total)
Table 2 / 6d / Customer hours of unplanned outages, not including PSPS (normalized)	See previous comment. TURN recommends this metric be modified as shown.	Customer hours of unplanned outages *resulting from wildfires*, not including PSPS (normalized)
Table 2 / 6e / Increase in System Average Interruption Duration Index (SAIDI)	SAIDI includes outages that are unrelated to wildfires and wildfire mitigation efforts. TURN recommends this metric be removed as a metric to measure the effectiveness of wildfire mitigation efforts.	
Table 2 / 7 / Electricity cost to ratepayers	TURN supports a metric that tracks costs to ratepayers related to wildfires, but recommends changes to clarify and simplify what would be tracked. Rates are complex with numerous rate schedules based on customer class and use. Translating cost increases into rate impacts is a complex endeavor that requires selection of representative customers and assumptions about electricity usage, among other things. A simpler measure would be to track wildfire-related costs (expenses and capital, separately) that have been authorized for recovery. In addition, rather than attempting to calculate increases, utilities should simply be required to annually report their wildfire related cost recovery for the next five years; increases can be determined by comparing those costs from year to year. TURN recommends tracking two distinct, non-overlapping categories of costs: 1) authorized cost recovery for mitigation activities; and 2) other wildfire-related cost recovery which could include costs of repair and remediation of utility facilities affected by wildfires, wildfire insurance, and wildfire liabilities. (TURN hastens to note that, because of the Wildfire Insurance Fund created by	In the Name column, change 7a and 7b to: "~~Increase in~~ Electric costs *authorized for rate recovery* due to wildfire *liability claims, wildfire insurance, and repair/remediation of utility facilities . . .*" In the Name Column, change 7c to: "~~Increase in~~ Electric costs *authorized for rate recovery* due to wildfire mitigation activities . . ." and add a 7d to require a normalized calculation. In the Unit(s) column, change 7a and 7b to: "*Total authorized expenses and total authorized capital expenditures for the next five years for wildfire liability claims, wildfire insurance and repair/remediation of utility facilities. . .*"

	AB 1054 to which ratepayers will contribute substantially, TURN does not expect ratepayers to be required to pay any additional costs for wildfire liabilities.) These costs should also be required to be presented in "normalized" form by dividing by the total number of circuit miles in HFTD. Wildfire cost recovery can change from year to year by virtue of true-ups and other between-rate-case decisions (e.g., CEMA, WEMA), so the collection frequency should be annual.	In the Unit(s) column, change 7c (and 7d) to: "*Total authorized expenses and total authorized capital expenditures for the next five years for wildfire mitigation activities…"* The 7a-7d costs should also be presented in normalized form by dividing by the utility's number of HFTD circuit miles. The Collection frequency should be changed to *Annual.*
Outcome Metrics – Leading, Externally-Sourced		
Table 2 / 9 / Impact of utility ignitions based on ignition simulation	TURN has similar concerns as noted regarding the Table 2, #5 metric above, including potential lack of standardization and transparency regarding utility models, calculations, and assumptions to derive the results. However, because these simulations could provide important information, utilities should be required to provide the information, models and inputs as a data submission under Attachment 1 or Attachment 5, to which the CPUC and WSD could give the appropriate weight based on their ability to assess the quality of the model and its inputs. In the long term, the CPUC/WSD should specify the model and require that all utilities use the same model, to allow for comparability of results.	
Outcome Metrics – Lagging, Externally- Sourced		
Table 2 / 11 / Fatalities from utility wildfire mitigation activities	The Commission should include, as a separate metric, fatalities that occur due to PSPS events. This tracks the most adverse consequence of utility PSPS events, which is critical for understanding the full impact of PSPS.	*Fatalities due to PSPS events (total).* *Fatalities due to PSPS events (normalized).*
Table 2 / 12 / OSHA-reportable injuries from utility wildfire mitigation activities	See comment above. Injuries to members of the public should be defined as injuries requiring medical care.	*Injuries due to PSPS events (total).* *Injuries due to PSPS events (normalized)*

Table 2 / 17 / Number of utility wildfire ignitions	While all ignitions that occur in a utility territory represent important data points, ignitions that occur in relatively high consequence areas (HFTDs) under high consequence conditions (RFWs) must be tracked and compared among utilities to understand relative progress in preventing the most significant events. In addition, data regarding ignitions that occur on lines where primary utility mitigations have been deployed – namely covered conductor and enhanced vegetation management – is critical for tracking the performance of these mitigation efforts over time as well as to compare with utility risk-mitigation assumptions. Furthermore, each ignition metric should present transmission and distribution-level incidents separately where applicable.	*Number of ignitions during RFW (total)* *Number of ignitions during RFW (normalized)* *Number of ignitions during RFW in HFTD (total)* *Number of ignitions during RFW in HFTD (normalized)* *Number of ignitions on lines with covered conductor (total)* *Number of ignitions on lines with covered conductor (normalized)* *Number of ignitions on lines subject to enhanced vegetation management (total)* *Number of ignitions on lines subject to enhanced vegetation management (normalized)*
Table 2 / 18 / Estimated GHG emissions from utility-ignited wildfire	To provide the most useful information, ideally, Cal ARB would provide GHG emissions for each catastrophic utility-caused fire event (e.g., Camp fire) to enable comparisons among the different fire events and across utilities.	

4. COMMENTS ON WMP GUIDELINES

Because Sections 2 and 3 of the WMP Guidelines overlap to some extent with the Attachment 4 Metrics, many of TURN's comments in Section 3 above are equally applicable to information that is required to be provided by the WMP Guidelines. In addition to those comments and the General Comments in Section 2 above, TURN offers the following specific comments:

ATTACHMENT 3

A.18-09-002, Borden Testimony, pp. 23-27

A.18-12-009, Borden Testimony, pp. 11-16

CPUC Docket: A.18-09-002
Exhibit Number:
Witness: Eric Borden

PREPARED TESTIMONY OF ERIC BORDEN

ADDRESSING SOUTHERN CALIFORNIA EDISON'S GRID SAFETY AND RELIABILITY PROGRAM INFRASTRUCTURE PROPOSAL

Submitted on Behalf of

THE UTILITY REFORM NETWORK

785 Market Street, Suite 1400
San Francisco, CA 94103

Telephone: (415) 929-8876 x307
Facsimile: (415) 929-1132
E-mail: eborden@turn.org

April 23, 2019

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> SCE did not investigate this specific fire and does not know if the fuse or the materials used in the fuse caused the fuse's operation to result in the fire.[44]

This one instance may have been an anomaly – either way, it is clear fuses are not significant drivers of wildfires in SCE's territory. Conventional fuses, while perhaps not as optimal as CLFs, help achieve risk mitigation through the reduction of energy during a fault. The strategy of replacing existing fuses is likely not cost-effective from a risk spend efficiency standpoint; unfortunately, SCE has not quantified the degree of risk mitigation from replacing fuses.[45] TURN therefore has no compelling evidence this strategy is worth the cost, and at a minimum the utility has not met its burden to demonstrate it is in the ratepayer interest. Further, replacement of existing fuses results in stranded costs at a time when affordability concerns for ratepayers must be adequately accounted for. Overall, TURN finds replacement of conventional fuses promises relatively little return (safety mitigation) for high cost; no incremental funding should be approved for the replacement of existing fuses. This results in a reduction to SCE's fusing mitigation proposal of $32.5 million.

D. Enhanced Vegetation Management

1. Overview

SCE proposes to inspect and, where possible, prune trees to greater clearances, from a recently adopted mandate of 4 feet to 12 feet in HFRAs.[46] SCE also proposes greater focus on living, healthy trees outside of the utility right of way (ROW). The utility explains it will,

> […]assess the structural condition of trees in HFRA that are not dead or dying, but could fall into or otherwise impact electrical facilities and potentially lead to ignitions and outages. These trees may be as far as 200 feet away from SCE's electrical facilities. Trees posing a potential risk to electrical facilities due to their structural or site condition will be removed or otherwise mitigated.[47]

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[44] TURN-06, question 26b.
[45] TURN-06, question 23f.
[46] SCE-1, p. 110, Footnotes 126 and 127.
[47] SCE-1, p. 111, lines 2-6.

SCE's target is for removal of up to 22,500 trees in 2019 and 2020, but states its "aspirational target" is 45,000 trees over the period, which is the basis of its cost estimate.[48] This activity, the removal of living, healthy trees, is the majority of the incremental cost proposed for enhanced vegetation management, as seen in Table 6 below.

Table 6: SCE Proposed Enhanced Vegetation Management By Program Area ($ 2018, Thousands)[49]

	2018	2019	2020	Total
Tree Removal	$ -	$ 30,218	$ 60,435	$ 90,653
Tree Removal – Property Owner Incentives	$ -	$ 404	$ 808	$ 1,211
Program Management	$ -	$ 4,692	$ 8,235	$ 12,927
Tree Trimming	$ -	$ 3,608	$ 7,217	$ 10,825
Tree Inspection	$ -	$ 1,226	$ 1,226	$ 2,452
Total	$ -	$ 40,148	$ 77,921	**$ 118,069**

2. TURN Supports Commonsense Measures to Increase Clearing Distances in HFRAs, but Not a Potentially Unnecessary, Damaging, and Costly Program to Remove Living, Healthy Trees Throughout the Territory

TURN supports the proposal to increase vegetation distances in HFRAs from 4 feet to 12 feet. It is important that SCE quantify the incremental risk reduction of this activity, as discussed in Section V.

However, TURN opposes any incremental funding for the removal of living, healthy trees in the name of wildfire risk mitigation. That is not to say that a greater level of pruning of trees further away may not be warranted in some situations. But SCE's proposal to completely remove living, healthy trees at a large scale suffers from fundamental flaws. At a minimum, SCE has not demonstrated the program is necessary or cost-effective for the mitigation of wildfire risk. TURN's analysis below indicates removal of living, healthy trees has a small risk-reduction benefit in combination with a high cost, the activity may not be accurately targeted to the riskiest trees, and SCE has no proposal for how to make up for the carbon increase expected due to this

[48] SCE-1, p. 123, lines 17-21.
[49] WP-SCE-02, Excel attachments for Vegetation Management.

tree removal. SCE has come nowhere close to justifying the cost and scope of this activity, based on the following discussion.

First, data indicates that living, healthy, trees are a relatively small driver of vegetation faults in SCE's territory. In fact, from 2015-2017 these trees likely caused around 1% of the vegetation faults on circuits with 2 or more faults over the period; and perhaps up to a maximum of 9% under very conservative assumptions.[50]

Second, there are around 500 tree-caused circuit interruptions per year, of which around 180 occur in HFRAs.[51] The vast majority of these "interruptions" are not due to living, healthy trees falling over. The removal of 45,000 trees over just a three-year period, with likely more to come as part of SCE's GRC, may literally be overkill.

Third, SCE's target is based on a "failure rate" of around 5%, meaning of the trees assessed it expects to remove at least 5%.[52] Yet, when TURN requested "all sources, workpapers, and studies that demonstrate this [SCE's maximum estimate] quantity of trees should be removed in HFRAs,"[53] SCE failed to clarify exactly what criteria are being used to determine this "failure" rate, and whether these living, healthy trees must truly be removed to mitigate wildfire risk. Since most vegetation events occur during the winter (Figure 6), likely during high-wind, rainy conditions when the risk and consequence of wildfire ignition is low, it is possible SCE's program will target trees that are at risk during a storm but not during hot, windy, dry conditions. TURN notes that where it is clear these dry and windy conditions are likely to occur with a significant degree of probability, they should also be targeted for covered conductor, power shutoffs, fuses, and other mitigation measures, decreasing the need for the removal of living, healthy trees. If Edison had better accounted for the overlap of its mitigation activities, this strategy would be more clear (Section V).

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[50] Calculated from attachment "Circuits with Multiple TCCIs 2015-2017." TURN tallied vegetation faults by category (e.g. wind blew palm frond, etc.) The 1% includes the clearest category of vegetation faults related to living, healthy trees, called "High winds uprooted a healthy tree." The 9% includes, conservatively, all categories where a living, healthy tree may have been involved (but may actually consist of predominately dead or sick trees). This includes the following categories, in addition to the healthy tree category: "Tree Uprooted, Normal Conditions," "Fallen Tree," "Uprooted Tree," and "Unstable Tree Failed."

[51] Attachment "TCCI w HFA Data Request_3-21-19." Average of 2015-2017.

[52] TURN-06, question 12.

[53] TURN-06, question 12.

Fourth, at an average estimated cost of about $2,000 per tree[54], SCE must carefully target only those trees most likely to fall over and cause an ignition in high consequence areas. It is not clear whether SCE's process effectively does this. And even if SCE were to have a perfect process and criteria for selecting trees for removal, the utility does not have control over what trees it can remove, since "most trees to be mitigated through this effort reside on private or public property, property owner approval is required to remove the trees."[55] This means that SCE may not be able to prioritize trees according to risk, potentially making the program even less cost-effective than it appears on its face.

Finally, TURN is concerned about the carbon impact of such large-scale tree removal. Trees act as carbon sinks – their removal will increase greenhouse gases (GHGs) and may have other negative ecological effects. SCE quantifies the GHG impact of its "aspirational target" tree removal to be 8,165 Metric Tons.[56] While this represents a small fraction of emissions in California, it will occur over just a three-year period; longer-term, should the Commission authorize such a program, the relative carbon increase should be compensated for.

3. TURN Recommendations Regarding Enhanced Vegetation Management

Based on the preceding analysis and discussion, TURN recommends incremental ratepayer funding for tree removal should be rejected, equating to a forecast reduction of $91.9 million in expenses over the three-year period.[57] The data indicates living, healthy trees do not pose undue risk to utility lines, and where they do, technologies like covered conductor or other mitigation measures may be deployed. Further, it is difficult to assess whether SCE will operate the program in an ecologically responsible, cost-effective manner, prioritizing only the trees that pose high consequence and likelihood for wildfires.

Given the potential for significant costs and risks to the environment, TURN recommends that an independent, third-party study be conducted to assess the efficacy, necessity (risk-reduction), and cost-effectiveness of live tree removal. If the report finds this removal is

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[54] Excel workpaper "Forecast-Removal." Total cost divided by total trees.
[55] SCE-1, p. 121, lines 2-3.
[56] TURN-06, question 12c.
[57] WP-SCE-02, Vegetation Management Excel workpapers, includes Tree Removal and Property Owner Incentives for Tree Removal.

necessary to cost-effectively mitigate wildfire risk, it should recommend strategies for how to narrowly target only the highest-risk living, healthy trees, and provide suggested criteria subject to Commission approval. The study should account for ecological and forestry concerns, including the effects of removing large, healthy trees on fires should they occur, as well as recommendations to account for carbon increases. The study should be applicable to all utilities since similar programs have been proposed in each territory.[58] TURN recommends ratepayer funding therefore be split among the large IOUs, though primary contracting responsibility could reside with the Commission.

III. THE COMMISSION SHOULD MITIGATE THE RATEPAYER IMPACT OF PREMATURELY-REPLACED ASSETS DUE TO PROPOSED WILDFIRE MITIGATION MEASURES

SCE's proposed capital investments will, in some cases, replace existing assets which are still operational and do not otherwise face any near-term risk of failure, thus creating prematurely-replaced asset costs. The effect for ratepayers is that they would bear costs for two pieces of equipment even though only one is installed. This is particularly clear for recently installed assets. Poles and conductor have a depreciation life of approximately 50 years, so equipment installed within the previous five years is less than 10% of the way through its typical depreciation life. Even after these assets are replaced, ratepayers will be paying for the recovery of the associated investment, plus taxes and return for years and even decades into the future absent action by the Commission. On top of that, they would be paying the costs associated with the new replacement investment.

TURN's primary recommendation is to remove from ratebase the net recorded plant amount for assets installed less than 5 years ago, so that ratepayers do not, for example, pay for two poles where only one is in service, where that circumstance is due to the utility's relatively late epiphany that its previous wildfire risk mitigation investments and strategies are inadequate. At the very least, the utility should not unduly profit from wildfire mitigation investments that effectively result in, for example, two poles when only one is in service. At a minimum, the Commission should reduce the authorized return on assets that have been installed in the

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[58] All three IOUs propose similar programs to remove living, healthy trees. See Wildfire Mitigation Plans and PG&E GRC.

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Witness: Eric Borden

PREPARED TESTIMONY OF

ERIC BORDEN

ADDRESSING PACIFIC GAS AND ELECTRIC'S ENHANCED VEGETATION MANAGEMENT AND SYSTEM HARDENING WILDFIRE MITIGATION EXPENDITURES

Submitted on Behalf of

THE UTILITY REFORM NETWORK

785 Market Street, Suite 1400
San Francisco, CA 94103

Telephone: (415) 929-8876 x307
Facsimile: (415) 929-1132
E-mail: eborden@turn.org

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Table 4. TURN vs. PG&E Overhang Clearing and Maintenance Forecast ($ 2018)

	2020		2021		2022		Total
	Overhang Clearing	Overhang Maintenance	Overhang Clearing	Overhang Maintenance	Overhang Clearing	Overhang Maintenance	Overhang Clearing and Maintenance
PG&E	$110,682,904	$32,195,908	$110,682,904	$94,080,468	$110,682,904	$126,276,376	$584,601,463
TURN	$58,104,399	$8,852,675	$58,104,399	$25,867,515	$58,104,399	$34,721,296	$243,754,682
TURN-PG&E	($52,578,505)	($23,343,234)	($52,578,505)	($68,212,953)	($52,578,505)	($91,555,080)	($340,846,782)

Table 4 presents the 2021 and 2022 amounts for overhang maintenance calculated using TURN's proposed unit costs for illustrative purposes, but TURN does not take a position on PG&E's request to specifically approve attrition year (2021 and 2022) amounts for overhang maintenance expenses.

B. Removal of Living, Healthy Trees on a Massive Scale is Unnecessary, Unjustified and Extremely Expensive

PG&E states that the Targeted Tree Species program is intended to "identify and prune or remove trees from…ten high risk species where they are tall enough to strike power lines, have a clear path to strike, and exhibit other potential risk factors (e.g., leaning or being weighted towards the power lines)."[23] Targeted tree species work involves pruning or removing living trees[24] that "are tall enough to strike power lines"[25] more than 4 feet outside the utility right of way. The program is focused on the top ten species PG&E claims have caused vegetation-related ignitions in its territory. The pace of tree removal is targeted to complete Tier 2 and 3 HFTDs over an eight-year period, or around 3,000 miles per year starting in 2020.[26]

Subsequent to the GRC filing, PG&E updated its program to include removal of *all* tall trees on the ten species list near powerlines, not only those with "potential risk factors." PG&E also states the program may be further changed if the utility sees fit:

[23] PG&E-4, p. 7-26, lines 1-5.
[24] Dead or dying trees are "part of the Tree Mortality Mitigation Program funded through CEMA." PG&E-4, p. 76, footnote 33.
[25] PG&E-4, p. 7-26, line 3.
[26] PG&E-4, p. 7-26. WP Table 7-11, line 1.

> PG&E's planned approach to the Targeted Tree Species scope within the Enhanced Vegetation Management program is to remove generally all trees of those targeted species with strike potential (tall enough to strike the line if they are to fail). However, as already noted, PG&E expects our wildfire risk reduction programs to continue to evolve over time as PG&E receives new information, more experience, and other inputs. Being less than a year old and representing an unprecedented scope of work for PG&E, the EVM program is no exception and may continue to evolve as PG&E gains experience, information and input going forward.[27]

PG&E forecasts an annual cost of almost $180 million based on removing 142,886 trees each year at a unit cost of $1,258 per tree..[28]

The impetus for PG&E's program to remove this large number of trees is that the ten targeted species "drive 75 percent of the vegetation-caused fire ignitions in Tier 2 and Tier 3 HFTD areas."[29] This single data point is not persuasive as a valid basis for the mass removal of living, healthy trees. It is important to note that sick and dying trees should already be removed by PG&E under other programs.[30] Vegetation or branches from trees further away may require greater pruning, but their removal is only necessary if a healthy tree has a high likelihood of falling over during dry, windy conditions when a resultant ignition would be most likely to create a high consequence wildfire. TURN recommends that the Commission 1) authorize only 10% of the annual cost, a reduction of $162 million in expenses, 2) require one-way balancing account treatment, and 3) require an independent study to evaluate the need for healthy tree removal.

1. PG&E Must Remove Only Those Healthy Trees that Pose Wildfire Risk

The key question then, and one that PG&E itself should have investigated before embarking on this costly and environmentally damaging program, is to what degree do living, healthy trees fall over due to high winds or any other reason, and thus cause ignitions in dangerous wildfire conditions? TURN investigated this fundamental question through discovery,

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[27] Response to DR TURN-20, Question 2 (emphasis added).
[28] WP Table 7-11. See, also, PG&E's Second Amended WMP, filed on April 25, 2019 in R.18-10-007.
[29] PG&E-4, p. 7-25, lines 22-23.
[30] PG&E-4, p. 7-26, Footnote 33 states "PG&E will continue to remove dead and dying trees that have the potential to contact its lines as part of the Tree Mortality Mitigation Program funded through CEMA as noted in Section F below."

and based on the data provided, approximately **4%** of the 2,000 ignitions in PG&E's territory reported from June 2014-2018 can be said to be the result of healthy trees falling over; the figure is **7%** for Tier 2 and 3 HFTDs.[31] In addition, the data suggests PG&E's program is much too large when one compares the scope of the problem with PG&E's proposed solution. Between June 2014 and 2018 there were 161 healthy and non-healthy trees that fell into powerlines in PG&E's HFTDs (Tier 2 and 3), an average of 36 trees per year.[32] Over this period, there were 46 total incidences of healthy trees that fell into power lines in Tier 2 and 3 HFTDs,[33] *an average of about 10 per year.* By contrast, PG&E's program targets *143,000 trees per year* for removal.[34] An intelligently targeted program to remove only the riskiest trees could dramatically reduce costs and environmental harm, saving both ratepayers and the environment while effectively mitigating the risk posed by tall trees outside of the utility right of way.

Initially, PG&E had proposed to "prune or remove" large healthy trees, but apparently later modified its plan to "remove" all trees in the ten "high-risk" tree species "regardless of condition."[35] PG&E has not demonstrated that its Tree Species removal proposal is necessary and cost-effective to mitigate wildfire risk posed by utility equipment. The damage to the environment due to the removal of hundreds of thousands of ostensibly healthy trees has not been quantified by PG&E. Further, at a cost of $180 million per year, the program should be carefully analyzed for potential effectiveness. The analysis presented above shows that healthy trees pose a much smaller risk to power lines than the proposed scale of the program. Only those healthy trees that truly pose a risk of ignition should be removed. TURN's recommendation of $18 million in annual expense is sufficient for this task.

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[31] Data provided in TURN-018, question 10, attachment 1. Columns F and G indicate whether a vegetation event was due to trunk or root failure (resulting in the tree falling over) and whether a post-incident examination determined a tree has "signs of disease/decay (internal or external).

[32] Of the 314 incidences due to living trees, 60 were not assessed and 93 were categorized as "other," or "the suspected cause was determined to be something other than the failure of the trunk or roots." Thus, 161 incidences were due to trees falling over, as indicated by trunk or root failure.TURN-018, question 10, Attachment 1.

[33] As defined by trunk or root failure.

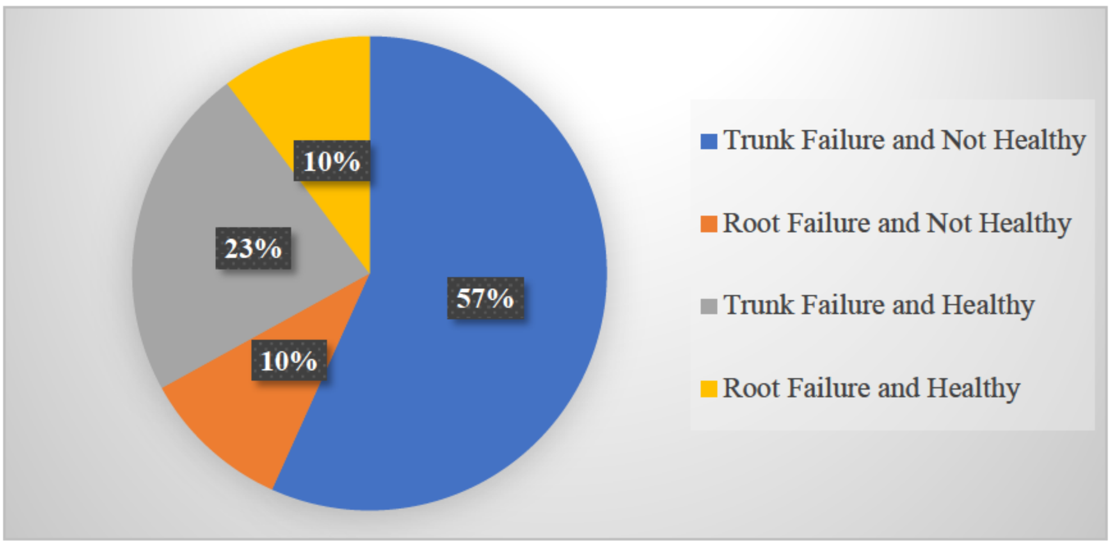
[34] WP Table 7-11.

[35] Response to DR TURN 035-02 and Attachment 2, p. 4.

2. PG&E Must do a Better Job of Removing Unhealthy Trees Near Powerlines

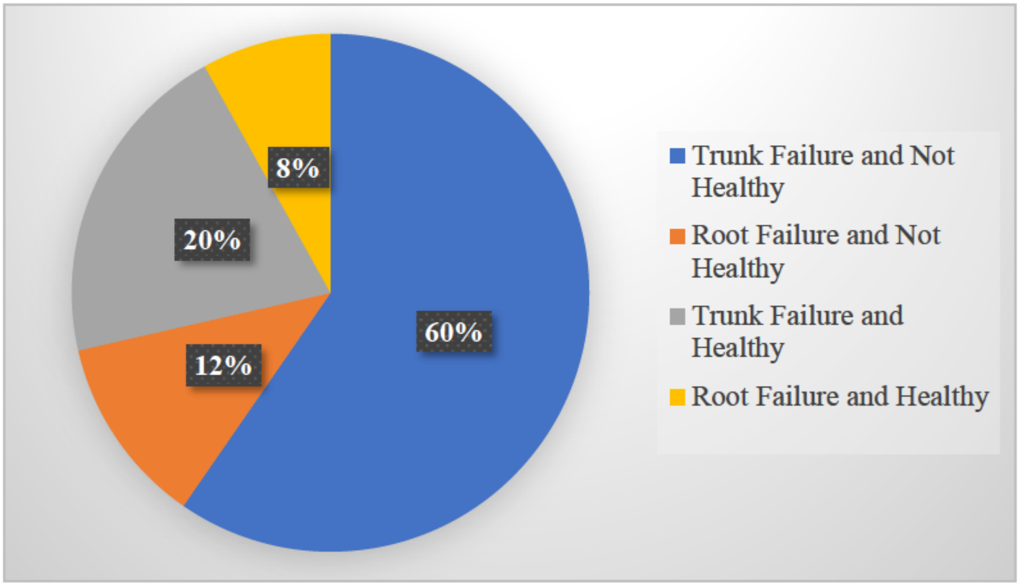
PG&E must do a better job of identifying and removing *unhealthy* trees, while removing only those healthy trees which truly pose a danger to power lines during dry, hot, windy conditions. The ignition data provided by PG&E shows that 215 ignitions were originally classified as caused by a living tree that fell over,[36] but once the health of the tree was assessed,[37] it turned out that 67% of these trees were actually *unhealthy*. The figure increases to 72% for ignitions due to "healthy trees" located in Tier 2 and 3 HFTDs.[38]

Figure 2. Ignitions Due to Unhealthy vs. Healthy Trees Falling Over
PG&E Service Territory



[36] Indicated by trunk or root failure in TURN-018, Question 10, Attachment 1.
[37] Of the 556 incidences due to living trees, 145 incidences were not assessed and 196 incidences were categorized as "other," or "the suspected cause was determined to be something other than the failure of the trunk or roots." TURN-018, question 10a and Attachment 1.
[38] Of the 314 incidences due to living trees, 60 were not assessed and 93 were categorized as "other," or "the suspected cause was determined to be something other than the failure of the trunk or roots." Thus, 161 incidences were due to trees falling over (trunk or root failure). TURN-018, question 10a and Attachment 1.

Figure 3. Ignitions Due to Unhealthy vs. Healthy Trees Falling Over PG&E Service Territory – Tier 2 and 3 HFTD



The data presented above indicates that PG&E must do a better job at identifying trees that are both *unhealthy* and pose a risk to powerlines, and removing them. A helpful risk mitigation measure would be to remove trees that may not be "visibly" unhealthy but do in fact show signs of rot or disease upon inspection and pose a risk to utility equipment. TURN understands that costs for this tree removal would be recorded in the CEMA,[39] though under TURN's recommendation for ratepayer funding (below), sufficient funds would be available if this is not the case.

3. The Commission Should Order an Independent Study of the Need for Healthy Tree Removal

To help clarify this issue third-party expertise is needed. In its testimony on SCE's Grid Safety and Reliability Program (GS&RP) TURN recommended an independent study to apply to all IOUs related to healthy tree removal programs:

[39] PG&E-4, p. 7-26, Footnote 33 states "PG&E will continue to remove dead and dying trees that have the potential to contact its lines as part of the Tree Mortality Mitigation Program funded through CEMA as noted in Section F below."

> Given the potential for significant costs and risks to the environment, TURN recommends that an independent, third-party study be conducted to assess the efficacy, necessity (risk-reduction), and cost-effectiveness of live tree removal. If the report finds this removal is necessary to cost-effectively mitigate wildfire risk, it should recommend strategies for how to narrowly target only the highest-risk living, healthy trees, and provide suggested criteria subject to Commission approval. The study should account for ecological and forestry concerns, including the effects of removing large, healthy trees on fires should they occur, as well as recommendations to account for carbon increases. The study should be applicable to all utilities since similar programs have been proposed in each territory. TURN recommends ratepayer funding therefore be split among the large IOUs, though primary contracting responsibility could reside with the Commission.[40]

Similarly, the Commission should order PG&E to fund an independent study to assess the need for, and possible scope of, its Targeted Tree Species program. In the meantime, TURN recommends that 10% of the proposed budget be approved, equivalent to the removal of 14,300 trees per year for $18 million annually, as a conservative safety measure.[41] This amount should be more than sufficient to mitigate risk if using appropriate criteria to target only those healthy trees that are likely to cause an ignition from falling over in dry, windy conditions.

C. TURN Overhang Clearing and Tree Species Removal Budget Recommendation

Based on the preceding analysis, TURN recommends adjustments to overhang clearing unit costs and a significantly more limited targeted tree species removal program. This results in the following budget for these programs.

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[40] Footnotes removed. See TURN Testimony in A.18-09-002, pp. 26-27.
[41] Calculated from WP Table 7-11.

ATTACHMENT 4

A.18-09-002, Exh. PG&E-18v1, Table 2A-2

E. PG&E's System Hardening Program

Q 18 Please provide an overview of the changes to PG&E's proposed System Hardening Program.

A 18 Table 2A-2 below summarizes the changes to PG&E's System Hardening Program, comparing the program described in my opening testimony and PG&E's current System Hardening Program proposal:

TABLE 2A-2
COMPARISON OF INITIAL SYSTEM HARDENING PROPOSAL AND CURRENT SYSTEM HARDENING PROPOSAL
(IN MILLIONS)

Line No.	Element	Initial System Hardening Program Proposal		Current System Hardening Program Proposal	
1	Total Circuit Miles for Program	7,100 miles		7,100 miles	
2	Program Execution Time	10 years		14 years	
3	**2020**				
4	**Element**	**Initial System Hardening Program Proposal**		**Current System Hardening Program Proposal**	
5	Overhead Hardening	600 miles	$729.5	188 miles	$289.1
6	Undergrounding	N/A	–	33 miles	204.1
7	Total Capital Cost (MAT 08W)		$729.5		$493.2
8	**2021**				
9	**Element**	**Initial System Hardening Program Proposal**		**Current System Hardening Program Proposal**	
10	Overhead Hardening	600 miles	$748.8	304 miles	$482.0
11	Undergrounding	N/A	–	54 miles	340.2
12	Total Capital Cost (MAT 08W)		$748.8		$822.2
13	**2022**				
14	**Element**	**Initial System Hardening Program Proposal**		**Current System Hardening Program Proposal**	
15	Overhead Hardening	600 miles	$768.8	376 miles	$612.6
16	Undergrounding	N/A	–	66 miles	432.4
17	Total Capital Cost (MAT 08W)		$768.8		$1,045.1

Q 19 Have there been any recent developments which would further support PG&E's System Hardening Program proposal?

A 19 Yes. On July 12, 2019, Governor Newsom signed into law AB 1054 which addressed, in part, wildfire issues. The Legislature stated that it had found that "[t]he state's electrical corporations must invest in hardening of the