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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

OPENING COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION

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The Energy Producers and Users Coalition[1] (EPUC) submits these opening comments pursuant to the *Assigned Commissioner's Scoping Memo and Ruling* issued on December 7, 2018. Pursuant to instructions given at the February 26, 2019 pre-hearing conference, these opening comments follows a common briefing outline sent out on the service list on March 8, 2019.

1. INTRODUCTION AND SUMMARY

Senate Bill (SB) 901, enacted in response to wildfire events in 2017, directs the investor-owned electric utilities to develop comprehensive plans to "minimize the risk of catastrophic wildfire."[2] The Wildfire Mitigation Plans (WMPs or Plans) submitted on February 6, 2019, are the utilities' first response to this directive and require the Commission's "review and approval" within an extremely compressed statutory schedule.[3] Consequently, consistent with the Commission's original statement of intent in the Order Instituting Rulemaking (OIR), its review

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1 EPUC represents the electricity end-use interests of the following companies in this proceeding: Aera Energy LLC.; California Resources Corp.; Chevron USA; PBF Holding Company; Phillips 66 Company; Shell Oil Company; and Tesoro Refining & Marketing Company LLC.

2 Senate Bill 901 (Stats. 2018, Ch. 626); Pub. Util. Code §3836(a) ("Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment").

3 *See* Pub. Util. Code §3836(e) ("The commission shall approve each plan within three months of its submission. . .").

and approval should center on "how to interpret and apply the statute's list of required plan elements, as well as whether additional elements beyond those required in statute should be included" in the Plans.[4] The Commission should make clear that its approval will not be an approval of the "reasonableness" of the programs and projects detailed in the Plans. Any determination of the reasonableness of the utility's programs and projects or their costs should take place consistent with the Commission's long-standing General Rate Case (GRC) processes, as Public Utilities Code §8386(g) requires.[5]

While costs are not determined in this proceeding, the utilities should take steps to ease future cost analysis in the GRC process. EPUC recommends that the Commission require the utilities to identify and track program expenditures based on what purpose they serve and how they should be functionalized. Starting this process now will facilitate a complicated GRC process when program costs are litigated.

In addition, more information will be required to assess the reasonableness of the programs, projects and costs, consistent with the Commission's directives for Risk Assessment and Mitigation Phase (RAMP) requirements for GRC proceedings. First, the Plans fail to illuminate the amount of risk reduction the utility will achieve through each mitigation measure and the associated "risk spend efficiency" of the investments. Second, they fail to identify metrics that will enable the Commission to determine whether the Plans have been successful in reducing risk. This information is necessary for assessing the reasonableness of the Plan's measures and therefore must be developed and provided when the utilities seek Plan funding.

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4 *Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)* (OIR), Oct. 25, 2018, at 4-5.

5 All code section references, unless indicated otherwise, refer to the Public Utilities Code.

For these reasons, EPUC requests that the Commission narrowly limit the scope of its approval of the Plans to determining whether they contain the statutorily required elements. EPUC further requests that the Commission specify the additional information that will ultimately be required to determine whether the programs, projects and costs the utilities' propose are reasonable and eligible for cost recovery.

2. MEANING OF PLAN APPROVAL

Section 8386(e) requires the Commission to review and approve each Plan "within three months of its submission." The lack of statutory guidance on this process, however, requires the Commission to determine the scope of its review and the import of its approval. An examination of SB 901 in the context of the Commission's existing regulatory framework and the expedited statutory schedule dictates a very narrow scope of review and approval for this proceeding. The only reasonable conclusion is that the Legislature intended for the Commission's review and approval to be limited to determining whether the Plans include all of the information SB 901 requires.

2.1 The Compressed Statutory Schedule Necessarily Limits the Scope of the Commission's Review

The statute's three-month schedule for this proceeding necessarily limits the scope of Commission review of the Plans. The Commission observed in its OIR that the rulemaking is a "first step." It further indicated that the Commission "does not expect to achieve perfection in the short time that will be available for the initial review and implementation of the first Plans, but will work with the parties to make the best use of that time to develop useful wildfire mitigation plans."[6]

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[6] OIR at 3.

Anything but an "initial review" is impossible for the Commission to achieve in three months. Existing Commission rules require 30 days for public comments and reply comments on a Proposed Decision[7] except in the case of "an unforeseen emergency situation."[8] An ALJ has up to 90 days to prepare a Proposed Decision.[9] Thus, in the normal course, the mandated three-month review and approval schedule would be unworkable. While the Commission is bound by statute to make this schedule work, there can be little doubt that the review must be tightly limited to a scope that can reasonably and meaningfully achieved.

Three possible levels of review could be considered. First, the Commission could see its responsibility as a review of the utilities' Plans to ensure that they reasonably include all of the statutorily mandated elements. This is most consistent with the OIR's scope, in which the Commission stated that it would consider "how to interpret and apply the statute's list of required plan elements, as well as whether additional elements beyond those required in statute should be included" in the Plans.[10] Completing a review within this scope is reasonable considering the extremely abbreviated process prescribed. Second, the Commission could undertake a review similar to the process that the Safety and Enforcement Division (SED) employs in reviewing RAMP filings as "Phase 0" of the utilities' GRCs. SED's role in reviewing the RAMP is:

> to consider the completeness of the utilities' report, including consistency and compliance [with] Commission orders, as well as to determine whether [the utility]: a) prioritized its risks, b) ranked its risks, c) described baseline controls

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7 *See* Rules of Practice and Procedure, Rule 14.3.
8 *Id.*, Rule 14.6.
9 *Id.*, Rule 14.2 (a).
10 OIR at 4-5.

> and costs, d) prioritize mitigations, e) risk mitigation plan, and f) examined two alternatives for each identified risk.[11]

SED's focus is on utility practices, not on the specific programs or projects that result from those practices. Notably, however, this RAMP process can take four months *even without* a full Commission decision.[12] Thus, this process-focused review of risk assessment and mitigation practices for WMPs is a more ambitious task than can be undertaken in the three-month mandated timeline. Third, the utilities suggest that the Commission's review should encompass a determination on the reasonableness of the specific programs or projects proposed in the Plan.[13] Conducting this type of review in three months is outside the realm of possibility, and this interpretation is unsupported by the statute, as explained in Section 2.2.

2.2 The Legislature Deferred Reasonableness Reviews of Costs to the Utilities' General Rate Case Process

While SB 901 does not illuminate the precise nature of the Commission's review, one point is clear: the Commission should not directly or indirectly pre-determine the reasonableness of the utilities' spending through Plan review. Section 8386(g) provides: "the commission shall consider whether the cost of implementing each electrical corporation's plan is just and reasonable in its general rate case application." Similarly, §8386(j) states:

> Each electrical corporation shall establish a memorandum account to track costs incurred for fire risk mitigation that are not otherwise covered in the electrical corporation's revenue requirements. The commission shall review the costs in the memorandum accounts and disallow recovery of those costs the commission deems unreasonable.

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11 *See, e.g.,* I.17-11-003, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company* (SED RAMP Report), March 30, 2018, at 3.

12 *See id.*

13 *Joint Response of Southern California Edison Company (U 338-E) and Pacific Gas and Electric Company (U 39-E) to Motions for Evidentiary Hearings by TURN and POC* (Joint Response), Feb. 25, 2019, at 3.

The question of cost recovery remains squarely within the bounds of existing Commission regulatory mechanisms. Statutory intent is further amplified by the fact that none of the 20 specific directives in §8386 calls for an investment plan or spending estimate; in fact, none of these directives includes the words "cost," "spending," "investment," or "budget."

A reasonableness review of Plan costs in a GRC cannot be reduced to an examination of whether the utility implemented a particular project at least cost. As The Utility Reform Network (TURN) explained, the Commission's rate case practice includes two determinations: "(1) whether the program itself is necessary, reasonable in scope and pace, and otherwise cost-effective; (2) if so, whether the costs to perform the scope of work that is found to be reasonable are themselves reasonable."[14]

Importantly, nothing in SB 901 expressly changes the Commission's ratemaking process, and history suggests the Legislature would have been clear had it intended to make a change. In 2002, Assembly Bill (AB) 57 replaced the Commission's traditional ratemaking process for purchased power with a procurement pre-authorization process.[15] The Legislature made clear, however, that it was changing long-standing Commission ratemaking practices.

Section 454.5(d)(2) states that the adopted procurement plans:

> Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses. However, the commission may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved.

Even that process, however, is not definitive. Section 454.5(h) provides:

> Nothing in this section alters, modifies, or amends the commission's oversight of affiliate transactions under its rules and decisions or the commission's existing

14 *Conditional Motion of the Utility Reform Network for Evidentiary Hearings*, Feb. 20, 2019, at 5.
15 Assembly Bill 57 (Stats. 2002, Ch. 835).

> authority to investigate and penalize an electrical corporation's alleged fraudulent activities, or *to disallow costs incurred as a result of gross incompetence, fraud, abuse, or similar grounds*.[16]

Most critically, however, the Legislature knew precisely how to modify the Commission's ratemaking process but did not do so in SB 901. Indeed, SB 1088,[17] which was proposed in the 2018 legislative session, would have made the change the utilities now attempt to read into SB 901 but was not enacted.[18] Absent clear statutory direction overriding existing Commission ratemaking processes, the Commission must conduct the general rate cases referenced by SB 901 in the usual manner.

2.3 The Utilities' Attempts to Lower the Performance Bar and Eliminate Reasonableness Reviews Must Be Rejected

PG&E and SCE markedly misinterpret the scope of the Commission's WMP review. They contend that "[a]pproval of the WMPs constitutes finding that implementing the WMPs is reasonable, subject only to a reasonableness review of the costs."[19] This interpretation oversteps the scope of Commission approval for the WMPs and crosses over into a GRC determination.

The utilities' framing is unsupportable for several reasons. First, as discussed in Section 2.1, it is outlandish to suggest that this proceeding affords time to review the granular detail of the proposed programs – *e.g.*, how many and which poles, how many miles, or how

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16 Cal. Pub. Util. Code §454(d)(2) (emphasis added).

17 Senate Bill 1088 (2018).

18 Senate Bill 1088 (2018) proposed language to Pub. Util. Code §2899.6(a), which made explicit that a finding that the utility was in "substantial compliance" with its approved plan meant that "the utility's performance, operations, management, and investments addressed in the plan are reasonable and prudent for purposes of any subsequent commission proceeding." SB 1088, §2899.6(a) (as amended on July 3, 2018). Even the last version of SB 1088, however, made clear that the Legislation did not intend "to create an obligation on the ratepayer to pay for a cost that was not just and reasonable. *Id.* §2899.6(c)(1).

19 Joint Response at 5.

many and which conductors.[20] Second, the Plans are largely conceptual, not detailed road maps for project execution, leaving a wide margin for implementing these high-level plans unreasonably. PG&E's Plan confirms this observation, identifying two pages of factors that could affect the costs of their programs – each of which presents the possibility of failure by PG&E in implementing its program. For example, it identifies as a variable "the actual number of miles completed,"[21] leaving the possibility that the Commission could determine that PG&E completed too few or too many projects in implementing its Plan. Third, the Plans do not present robust investment plans of the type the Commission would expect in a GRC when determining that a project is reasonable. PG&E's Plan, for example, limits cost information to a high-level cost-estimate in Attachment E.[22] Fourth, as discussed in Section 2.2, the Legislature did not modify the Commission's two-step ratemaking processes in SB 901, and the Plan costs will thus be addressed in business as usual in the GRCs. There is no basis upon which the utilities can support their statutory interpretation or the Commission's "review and approval."

The utilities take their interpretation one step farther. SCE proposes that "demonstrating substantial compliance with the Commission-approved WMP requirements should facilitate the Commission's subsequent reasonableness review of the costs recorded to SCE's SB 901 or other appropriate memorandum account."[23] PG&E similarly suggests that substantial compliance with its work targets are sufficient to demonstrate reasonableness:

> PG&E has included targets that are intended to enable the CPUC to evaluate compliance with this Plan, as required under PUC Section 8386(h). Substantial compliance with the targets set forth in the Plan, once approved by the CPUC,

[20] EPUC notes again that even a high-level review of a risk assessment and mitigation plan by SED, without processing a full Commission decision, takes four months. *See* SED RAMP Report at 3.
[21] *Pacific Gas and Electric Company's Wildfire Mitigation Plan*, Feb. 6, 2019, at 141-142.
[22] *Id.*, Attachment E.
[23] *Southern California Edison Company's (U 338-E) 2019 Wildfire Mitigation Plan* (SCE WMP), Feb. 6, 2019, at 8.

> should demonstrate that PG&E acted prudently and met the CPUC's "reasonable manager" standard, in regard to wildfire risk mitigation.[24]

The Commission must reject this interpretation.

As a preliminary matter, their argument assumes the Commission approves the details of their Plans as reasonable – *e.g.,* the type and extent of programs, specific projects, program pace, etc. As discussed above in this section, this proceeding was not intended, nor is there sufficient time, to review the details of the Plans. Moreover, while this measures activity level, it does not reveal whether the right activities were performed or if they were done so in a cost-effective manner. This limited analysis would not be sufficient even if the Commission had held extensive hearings to develop a plan and is certainly not sufficient where, as here, the Plans are allowed to go into effect without evidentiary scrutiny.

In addition, the utilities' approach tortures the "reasonable manager" standard by assuming that completing work as targeted is *per se* reasonable regardless of the way in which the utility performed the work or circumstances that might have made performance unreasonable. Deviations from a work plan may be prudent in certain circumstances. For example, if the experience of implementing a measure provides a new perspective on program efficacy or cost-effectiveness, then changes in direction would be prudent. In addition, new techniques and devices that are more effective than originally planned may be available after Commission approval. In these cases, strict compliance with the WMPs would be *imprudent.*

All of the utilities' attempts to set the bar of performance as low as possible must be rejected. The reasonableness of the activities they undertake, the way in which the activities are

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[24] *Pacific Gas and Electric Company's Wildfire Mitigation Plan* (PG&E WMP), Feb. 6, 2019, at 132.

performed and the cost of their performance must wait for review until a GRC, where the process affords adequate examination.

2.4 The Commission Should Direct the Utilities to Track and Organize Expenditures Now to Allow for Future Functionalization

While the Commission's ability to conduct a ratemaking review in the WMP applications is limited, as discussed in Section 2, it can take action to ease the ratemaking process in the GRC. In its presentation materials on February 13, 2019, PG&E estimated that its program costs would total between $1.7 billion and $2.3 billion, and SCE estimated its program costs would total between $550 million and $600 million.[25] As presented in the table below, both PG&E's and SCE's WMPs are comparable to the revenue requirement increase contemplated within a single GRC, a process that often takes over one year to litigate. It is worth noting that in a GRC, the Commission then has 90 days to issue a proposed decision,[26] three times the space allotted in this proceeding.

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25 Utility Mitigation Plan Workshop Materials, *available here*: http://www.cpuc.ca.gov/General.aspx?id=6442460388.

26 Rules of Practice and Procedure, Rule 14.2(a).

Comparison of Wildfire Plan Costs Presented in R.18-10-007 to Increases Proposed in General Rate Cases ($/Millions)

Line	Description	Pacific Gas and Electric Company (1)	Southern California Edison Company (2)
	2019 Wildfire Plan Cost Estimates:[1]		
1	Expenses	$800-$900	$290-$334
2	Capital Investment	$900-$1,400	$237-$346
3	Total	$1,700-$2,300	$527-$680
	Plan Revenue Requirement		
4	Expenses	$800-$900	$290-$334
5	Capital Service[2]	$110-$170	$30-$40
6	Total Revenue Requirement	$910-$1,070	$320-$374
	Increases Proposed in Phase One GRC's:		
7	A.18-12-009 (2020), or PG&E GRC	$1,058	
8	A.16-09-001 (2019), SCE's GRC		$491

(1) February 13, 2019 Workshop Presentation
(2) Capital Expenditures times a conservative 12% for return, taxes and depreciation

Given these momentous figures, EPUC recommends identifying and tracking expenditures in a comprehensive way immediately so that capital costs and expenses can be assigned (or if not assigned, appropriately allocated) for cost recovery in rate cases. Organizing and tracking expenditures by function will allow for more accurate assignments of costs when utilities request recovery in rates.

While cost recovery will be presented in a future rate case, individual customer classes bear different responsibilities for different kinds of properties. This process can be preliminarily demonstrated by SCE's data response to EPUC, attached as Attachment A.[27] Since many of the

27 Attachment A, SCE Response to EPUC Data Request, Set 1, Question 16.

programs and activities identified in the WMPs cut across both transmission and distribution functions, it is important to identify and track the expenditures associated with the transmission system and those associated with the distribution system. Unless these costs are properly identified at the time the expenditure occurs, it may be difficult to accurately assign costs between functions, which could lead to improper assignments of cost responsibility to customer classes. EPUC recommends that the Commission require the utilities identify costs at the time incurred, at least preliminarily, by their function.

In addition, because the Federal Energy Regulatory Commission (FERC) regulates part of the transmission system, it is important to identify costs associated with the transmission system that are subject to FERC regulation. This is because the Commission is not able to direct ratepayer cost recovery on any work performed on the transmission system in FERC's jurisdiction.

3. OVERALL OBJECTIVES AND STRATEGIES

4. RISK ANALYSIS AND RISK DRIVERS

The WMPs do not uniformly meet the Commission's standards for risk assessment and mitigation. Public Utilities Code §8386(c) directs the utilities to include in their WMPs:

> (10) 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*. The list shall include, but not be limited to, both of the following:
>
> (A) Risks and risk drivers associated with design, construction, operations, and maintenance of the electrical corporation's equipment and facilities.

> (B) Particular risks and risk drivers associated with topographic and climatological risk factors throughout the different parts of the electrical corporation's service territory.[28]

In addition, §8386(d) requires the Commission to "verify that the plan complies with all applicable rules, regulations, and standards, as appropriate." The WMPs do not meet the Commission's expectations for RAMP filings as articulated in its Safety Model Assessment Proceeding (S-MAP) decisions.

As the statute requires, the WMPs contain lists and descriptions of risks and drivers and responsive mitigation measures that are likely to have some effect on risk. They fail to provide adequate information, however, to allow the Commission to understand the magnitude of the risk a particular mitigation measure aims to address or the likely reduction in risk that will result. Likewise, the WMPs fail to provide clear metrics that will allow the Commission to assess the success of a measure following its implementation. While it is impracticable to expect the utilities to present this information, and for the Commission to conduct a meaningful review, on the timeline provided by the Legislature, the Commission can address the issue in two ways. The Commission should (i) clarify that its scope of review does not examine whether the WMPs include the right programs at the right pace to optimize risk reduction and (ii) require that this information be provided if and when the utilities formally seek funding in their GRCs or in a separate application.

4.1 The Plans Fail to Illuminate the Amount of Risk Reduction the Utility Will Achieve Through Each Mitigation Measure

The Commission developed a methodology to address risk assessment and the choice of mitigations best suited to address the risk in the S-MAP proceeding.[29] Among other features, the

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[28] Pub. Util. Code § 8386(c)(10) (emphasis added).

[29] *See* D.16-08-018.

Commission directed in D.16-08-018 that RAMP filings must calculate "risk reduction and a ranking of mitigations based on risk reduction per dollar spent"[30] (also known as Risk Spend Efficiency or RSE). The Commission explained that "'***prioritizing based on cost effectiveness measures is … an important step to optimizing portfolios.***'"[31] The goal of an RSE is to "prioritize projects in order to get the most risk reduction for money spent…."[32] While an RSE calculation is not included expressly in the Legislature's list of plan elements, because the statute requires that the WMP be at least as rigorous as RAMP filings, the WMPs should have included RSEs and rankings.[33] Neither SCE nor PG&E, however, has presented this information in their WMPs.

Recognizing the absence of these calculations in PG&E's RAMP, ALJ Thomas asked PG&E to provide "Risk Spend Efficiency (RSE) values for all mitigations provided in the WMP" with supporting workpapers. [34] Implicitly acknowledging the absence of RSEs in its WMP filing, PG&E responds that it included an RSE "for each" mitigation in its 2020 GRC, including wildfire mitigations.[35] In fact, PG&E's 2020 GRC testimony shows that PG&E determined RSEs for eight of the 21 wildfire-related mitigation measures, which vary depending upon the years forecast.[36] Moreover, the calculations are for what PG&E refers to as the "tail average" RSE, framing the risks as worst case.[37] As SED previously noted, framing the risks as worst case makes it difficult to measure a reduction in the consequence variable of the risk

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30 *Id.* at 3, 152-153.
31 *Id.* at 152 (quoting Joint Intervenors' Comments on Staff Report).
32 *See* SED RAMP Report at 25.
33 *Id.*, §8386(c)(10).
34 *Administrative Law Judge's Ruling Seeking Additional Information on Wildfire Mitigation Plans*, Feb. 21, 2019, at 2.
35 *Pacific Gas and Electric Company's (39 E) Response to Administrative Law Judge's Ruling Seeking Additional Information on Wildfire Mitigation Plans*, Feb. 26, 2019, at 7.
36 *Id.*, Attachment C, Table 2A-9 at page 2A-41.
37 SED RAMP Report at 25.

calculation.[38] Finally, and critically, PG&E does not state that these RSEs apply both in evaluating its GRC request and the incremental actions proposed by the WMP.

ALJ Thomas did not pose the same question to SCE. SCE's WMP, however, likewise lacks RSEs or any discussion of risk reduction values. While SCE included values for "mitigated risk reduction" and RSEs in its 2018 RAMP Report,[39] its WMP does not attempt to relate the RAMP RSEs to the measures included in the WMP. This runs contrary to the Commission's observation in D.16-08-018 that "SCE intends to prioritize mitigation spending by taking Risk Spend Efficiency into consideration."[40]

Without this information on the mitigated risk reduction or RSE for the utilities' proposed mitigation measures, the Commission is unable to make an informed judgment on the adequacy of the mitigation plans. While there is common sense appeal that each of these measures would reduce risk, the Commission must have sufficient information to understand (1) the value of the incremental measures above existing GRC spending and (2) the relative values of the measures to ensure resources are most effectively targeted.

While the Commission cannot find that the WMPs propose the right mitigation measures at the right pace to ensure effective risk reduction without the missing information, this may not be fatal to the WMPs. The Commission can acknowledge the limits of its WMP review and permit the utilities to present these important measures when they ask for funding in either a separate application or in their GRCs.

38 *See id.*

39 *See, e.g.,* I.18-11-006, *Southern California Edison Company's (U 338 E) 2018 Risk Assessment and Mitigation Phase Report*, at 10-44. Unlike PG&E, SCE presented its RSEs for both the "mean" and "tail" risks.

40 D.16-08-018 at 18.

4.2 The Plans Fail to Provide Metrics Sufficient to Enable the Utilities or the Commission to Assess the Effectiveness of Proposed Mitigation Measures

Not only do the WMPs fail to identify the risk reduction or RSE of the proposed mitigation measures, they do not provide performance metrics that the utility and Commission can employ to evaluate the effectiveness of the measures following their implementation. ALJ Thomas recognized this gap, asking the utilities to identify:

> What factors does the filer intend to measure and/or track in order to establish a causal effect between a specific mitigation measure and an anticipated/intended outcome (*e.g.,* reduced frequency of ignition or spread of wildfire)? Identify factors regardless of whether the filer refers to them as a metric, an indicator, or any other term.[41]

The ALJ likewise asked PG&E a more detailed question regarding metrics for its WMP.[42] The utilities' responses to these questions demonstrate a need for continued focus on the development of appropriate metrics. Certainly, the metrics as they exist now do not meet the burden of proof needed to supply ratepayer funding.

PG&E recognizes the need for performance metrics, stating that it will "analyze appropriate metrics – also called indicators – to assess the Plan's performance in reducing wildfire ignitions."[43] PG&E defines an "indicator" as a measure "used to identify and track a trend resulting from performance of the Plan programs."[44] It appears that "indicators" roughly equate to the outcome PG&E seeks to avoid. For example, PG&E proposes to examine trends in "wires down events" and "equipment caused ignitions to assess the effectiveness of its grid

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41 *Administrative Law Judge's Second Ruling Seeking Additional Information on Wildfire Mitigation Plans*, March 5, 2019, at 1.
42 *Administrative Law Judge's Ruling Seeking Additional Information on Wildfire Mitigation Plans*, Feb. 21, 2019, at 1.
43 PG&E WMP at 131.
44 *Id.* at 132.

hardening investments.[45] PG&E also points to "evaluation metrics" as required by §8386(c)(4) in Attachment E of its Plan, which references back to Table 9 of Section 4.[46] PG&E states that it "will assess performance of the Plan by evaluating the degree to which it has met the targets set forth in Table 9."[47] As PG&E explains: "A **target** is defined as a specific goal that addresses either the work executed to reduce risk and/or the quality of the work executed."[48] Targets include, for example, completing a number of patrols or "removing or working all dead or dying trees" it identifies.[49] In contrast to an intended outcome, a "target" measures tasks completed.

SCE takes a similar approach. Table 6-6 of its Plan is entitled "Metrics" and also uses "goals" that are units of work performed.[50] For example, "metrics" include "circuit miles inspected" and "number of trees removed."[51] It also describes "indicators," such as the number of "wire down events" and ignitions from equipment failures.[52] SCE's description of "indicators" roughly equates to the intended outcomes specifically regarding potential wildfire triggers.

While the utilities' approach offers these forms of metrics, the metrics are insufficient in two ways. First, they do not show a causal relationship between a particular mitigation measure and an "indicator," or outcome. This is the crux of ALJ Thomas' question on the "causal effect" between the mitigation measure and the outcome. They will perform the mitigations and will analyze the trends in indicators. They fail, however, to connect the mitigation measure with an outcome. SCE claims that this is challenging because uncontrollable factors make it "difficult to

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45 *Id*. at 134.
46 *Id.* at 39-45.
47 *Id.* at 131.
48 *Id.* (emphasis in original).
49 *Id.* at 135.
50 SCE WMP at 91, Table 6-6.
51 *Id.*
52 *Id.* at 93.

set accurate, achievable and numerical goals in 2019."[53] Second, since there is no targeted level of risk reduction, it is impossible to know whether the mitigation measure achieves its intended level of risk reduction.[54]

The lack of risk reduction target or metric to examine the effectiveness of a measure leaves open the question of whether the mitigation proposed measures will cost effectively address the existing and future risks. SCE suggests that "[c]umulatively, the success of the individual programs and activities in this WMP are expected to result in an overall reduction of controllable fire ignition events."[55] It cannot say, however, the extent to which this could be expected, nor the extent to which its mitigation spending will contribute to this result. Without this information, the utilities cannot expect the Commission to approve the programs or projects outlined in their Plans.

As with the utilities' risk analysis, the Plans' metrics need continued development. This must be completed and analyzed before reasonableness of the program and subsequent ratepayer funding can be authorized.[56]

5. WILDFIRE PREVENTION STRATEGY AND PROGRAMS

6. EMERGENCY PREPAREDNESS, OUTREACH AND RESPONSE

7. PERFORMANCE METRICS AND MONITORING

EPUC addresses its recommendations for metrics and monitoring in Section 4.2 in its

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53 *Id.* at 90.

54 SCE notes that it "did not evaluate the specific risk reduction resulting from this compliance activity as it is prescriptively required." *Id.* at 27.

55 *Id.* at 9.

56 The Commission described this determination as follows: "Virtually everything a utility does some nexus to safety and can be deemed to have some safety impact, but the emphasis should be on those initiatives that deliver the optimal safety improvement in relation to the ratepayer dollar spent." D.14-08-032 at 28. The Commission also stated: "In other cases, we decline to approve any funding for certain programs where we find that the claimed benefits do not justify the costs to ratepayers." *Id.* at 29.

discussion on how the utilities analyze risk and how they measure steps taken to address those risks. As discussed in Section 4.2, analysis connecting the mitigation measure and the outcome is lacking and should be developed in the Plans.

8. RECOMMENDATIONS FOR FUTURE WMPs

9. OTHER ISSUES

10. CONCLUSION

EPUC appreciates the opportunity to submit these comments and requests that the Commission consider the recommendations offered herein in reviewing the Plans.

March 13, 2019

Respectfully submitted,

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Attachment A
SCE Response to EPUC Data Request, Set 1, Question 16

Question 1-16: EPUC 1-16. For each program in SCE's Wildfire Mitigation Plan that is identified below, please state which of the following purposes it would be categorized in out of the following options: generation, distribution, and transmission. If any programs fall within more than one category, please estimate the percentages.

a. Alternative Technology Pilots
b. GSRP Wildfire Mitigation Program Study
c. Alternative Technology Evaluations
d. Alternative Technology Implementation
e. Distribution Enhanced Overhead Inspections and Rededication in HFRA
f. Transmission Enhanced Overhead Inspections and Remediation in HFRA
g. Quality Oversight / Quality Control of Enhanced Overhead Inspections
h. Infrared Inspection of Energized Overhead Distribution Facilities and Equipment
i. Infrared Inspection, Corona Scanning, and High Definition Imagery of Energized Overhead Transmission Facilities and Equipment
j. AGP- Drive By of Overhead Distribution Facilities and Equipment
k. Automatic Reclosers and Replacement Program
l. Capacitor Bank Replacement Program
m. Detailed Inspection of Transmission Facilities and Equipment
n. Deteriorated Pole Program
o. Insulator Washing
p. IPI – Intrusive Pole Inspections to Identify Rot and Decay
q. ODI – Detailed Inspections of Distribution Overhead FAcilitise and equipment
r. Overhead Conductor Program
s. PCB Transformers Replacement Program
t. Perfromance of Joint Patrols with Fire Agenceis
u. Pole Brushing
v. Pole Loading Program
w. PSPS/eE-energization Protocol Support Costs
x. Road and Right- of Way- Maintenance
y. Substation Inspection and Maintenance
z. Supplemental Inspections of HFRA
aa. Transmission Line Rating Remediation
bb. Wildfire Infrastructure Protection Team Additional Staffing cc. De-Energization Notifications
dd. Additional Weather Stations ee. Fire Potential Index Phase II
ff. Additional HD Cameras
gg. High-Performing Computer Weather Modeling System hh. Develop Asset Reliability &

Risk Analytics Capability
ii. Covered Conductor
jj. Evaluation of undergrounding in HFRA kk. Composite Poles and Crossarms
ll. Branch Line Protection Strategy
mm. Remote Controlled Automatic Reclosers Installation nn. Remote Controlled Automatic Reclosers Setting Updates oo. Circuit Breaker Fast Curve
pp. Hazard Tree Mitigation Program qq. Expanded Pole Brushing
rr. Expanded clearance distances at time of maintenance ss. DRI Quarterly Inspections and Removal
tt. LiDAR Inspections of Transmission

Response to Question 1-16:
SCE objects to the question as irrelevant, overbroad, and unduly burdensome. The guidelines used to separate, for ratemaking purposes, assets and expenses between those subject to FERC jurisdiction and those subject to CPUC jurisdiction are not within the scope of this proceeding. This proceeding relates to the approval of SCE's 2019 Wildfire Mitigation Plan and the programs and activities stated therein, not the cost recovery of and/or ratemaking associated with those programs and activities. Notwithstanding those objections, please see the table below.

Purpose	Generation (CPUC)	Transmission (FERC)	Transmission (CPUC)	Distribution[1] (CPUC)
a. Alternative Technology Pilots				√
b. GSRP Wildfire Mitigation Program Study				√
c. Alternative Technology Evaluations				√
d. Alternative Technology Implementation				√
e. Distribution Enhanced Overhead Inspections and Rededication in HFRA				√
f. Transmission Enhanced Overhead Inspections and Remediation in HFRA		√	√	
g. Quality Oversight / Quality Control of Enhanced Overhead Inspections				√
h. Infrared Inspection of Energized Overhead Distribution Facilities and Equipment				√
i. Infrared Inspection, Corona Scanning, and High Definition Imagery of Energized Overhead Transmission Facilities and Equipment		√	√	
j. AGP- Drive By of Overhead Distribution Facilities and Equipment				√
k. Automatic Reclosers and Replacement Program				√
l. Capacitor Bank Replacement Program				√

m. Detailed Inspection of Transmission Facilities and Equipment		√	√	
n. Deteriorated Pole Program		√	√	√
o. Insulator Washing		√	√	√
p. IPI – Intrusive Pole Inspections to Identify Rot and Decay		√	√	√
q. ODI – Detailed Inspections of Distribution Overhead FAcilitise and equipment				√
r. Overhead Conductor Program				√
s. PCB Transformers Replacement Program				√
t. Perfromance of Joint Patrols with Fire Agenceis				√
u. Pole Brushing				√
v. Pole Loading Program		√	√	√
w. PSPS/eE-energization Protocol Support Costs				√
x. Road and Right- of Way- Maintenance		√	√	
y. Substation Inspection and Maintenance		√	√	√
z. Supplemental Inspections of HFRA		√	√	√
aa. Transmission Line Rating Remediation		√	√	
bb. Wildfire Infrastructure Protection Team Additional Staffing				√
cc. De-Energization Notifications				√
dd. Additional Weather Stations[1]				√
ee. Fire Potential Index Phase II				√
ff. Additional HD Cameras[1]				√
gg. High-Performing Computer Weather Modeling System[1]				√
hh. Develop Asset Reliability & Risk Analytics Capability				√
ii. Covered Conductor				√
jj. Evaluation of undergrounding in HFRA				√
kk. Composite Poles and Crossarms				√
ll. Branch Line Protection Strategy				√
mm. Remote Controlled Automatic Reclosers Installation				√
nn. Remote Controlled Automatic Reclosers Setting Updates				√
oo. Circuit Breaker Fast Curve				√
pp. Hazard Tree Mitigation Program				√
qq. Expanded Pole Brushing		√	√	√
rr. Expanded clearance distances at time of maintenance		√	√	√
ss. DRI Quarterly Inspections and Removal		√	√	√
tt. LiDAR Inspections of Transmission		√	√	

Notes:

1. Also includes General or Intangible Plant such as "Additional Weather Stations" or "HD Cameras"