TURN THE UTILITY REFORM NETWORK

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VIA EMAIL ONLY

March 19, 2021

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: TURN Comments on the Energy Rates and Costs *En Banc*

On February 24, 2021 the California Public Utilities Commission (the Commission) hosted an *En Banc* concerning Electricity Rates and Costs. The Commission also released a White Paper entitled "Utility Costs and Affordability of the Grid of the Future," authored by staff in the Commission's Energy Division and containing extensive data and analyses in addition to the analyses typically provided in the annual costs and rates report prepared pursuant to SB 695. Pursuant to the Commission's direction, TURN submits these informal written comments on the *En Banc*.

Introduction and Summary

TURN applauds the Commission and staff on the comprehensive analysis of the alarming trajectory of California electricity rates and costs, and TURN strongly supports the work of the Commission staff to understand rates and affordability. While the White Paper provides extensive analyses, and many other issues were raised and discussed during the course of the *En Banc,* TURN's informal comments are limited to highlighting a few key input assumptions in the White Paper that may understate future rate increases, especially for PG&E.

While the development and use of the Cost and Rate Tracking Tools (CRT) to begin to forecast long-term rate trends is groundbreaking, the use of the CRT should not be a one-time undertaking. As the White Paper explains, the CRT has wide ranging uses.[1] The CRT outputs will be used to calculate Affordability Metrics pursuant to R.18-07-006, to inform Commission decision-making and to project medium term comprehensive rate forecasts and overall rate trends. In this type of forecasting, there is a significant degree of uncertainty. For this reason, TURN suggest the CRT forecast be run on a range of assumptions and not just base values for key variables.

[1] White Paper, p. 45.

As the White Paper explains, only PG&E has made its model and inputs publicly available. SCE and SDG&E have not publicly disclosed their inputs into the rate forecast. Thus, TURN was only able to review the forecast assumptions related to PG&E.

TURN suggests that the rate and bill impact forecasts in the White Paper potentially underestimate future rate increases, and recommends that the analyses would be improved by evaluating a number of sensitivity scenarios. TURN suggests the following critical inputs should be tested and/or modified:

- The use of a 4.5% escalator for PG&E's costs is likely too low, and a higher number would better reflect historical rate base growth.
- The CEC mid-case sales forecast presumes roughly flat to slightly declining sales which is at odds with recent IOU experience suggesting that a sensitivity using CEC low-case would be valuable.
- The analysis for PG&E should include a sensitivity case using higher costs, as it appears that the costs inputs potentially ignore up to $22 billion in spending by PG&E over the next decade.
- The analyses should separately present results for CARE and Non-CARE rates in addition to average rate and bill impacts.

<u>A Higher Post 2023 Rate Escalation Should be Tested</u>

As the White Paper explains, rates are a function of revenue requirement growth and sales growth. As one of its Key Findings, the White Paper correctly identifies electric rate base growth as a primary driver of rising rates.[2] In addition, it rightly calls out declining bundled electricity sales as an aggravating factor.[3] TURN's understanding is that the CPUC forecast method is based on 2020 rates adjusted for known costs filed or pending through 2023, but thereafter relies on the California Energy Commission (CEC) annual rate escalation of 4.5% for both electric distribution and transmission. The *En Banc* forecast uses the CEC mid-level bundled residential sales forecasts for all IOUs. All of the revenue requirement and costs forecasts beyond what has been filed or is already reflected in rates is provided in quarterly updates by the IOUs.

Based on the PG&E forecast, CPUC's assumption of a 4.5% annual revenue requirement escalation appears low relative to PG&E's historical growth rate of 5% per year since 2016[4] or PG&E's average annual transmission and distribution rate base growth of nearly 12% annually from 2006 though 2016.[5] Based on its most recent public investor presentations, PG&E projects

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[2] "The growth in rates can be largely attributed to increasing in capital additions driven by investments in transmission by PG&E and distribution by SCE and SDG&E." Utility Costs and Affordability of the Grid of the Future, CPUC Electricity Rates and Costs En Banc, February 24, 2021, p. 7.

[3] "As a result, declining utility sales result in larger rate increases as utility fixed costs are now spread across fewer units of usage." Ibid, p.14.

[4] <u>Utility Costs and Affordability of the Grid of the Future</u>, CPUC Electricity Rates and Costs En Banc, February 24, 2021, p. 20.

[5] Data calculations based on Distribution and Transmission Rate Base figures from CPUC Website, Energy/Electric Costs/Rate Base: https://www.cpuc.ca.gov/General.aspx?id=12092

rate base growth of 7%-8% through 2025.[6] TURN suggests that the CPUC run a revenue growth assumption using projected rate base growth as a proxy for revenue growth.

A Lower Sales Forecast Should be Tested

The CPUC analysis was based on the CEC mid demand sales forecast case which results in relatively flat residential sales with a slight decline over the 10 years 2020-2030. By comparison, the CEC low demand Case reflects a roughly 1% annual decline in bundled sales.[7]

This scenario of bundled residential sales loss and distribution and transmission rate base/revenue growth more consistent with historical experience, results in an escalation factor of 8% annually.[8] TURN estimates that this scenario would result in 2030 rates of more than 36 cents per kWh compared with the base forecast of 32.9 cents, or average residential rates of roughly 10% higher. This does not consider differences in tax treatment for accounting versus ratemaking resulting in deferred taxes which, when they come, due will increase costs paid by ratepayers.

Residential Rate Impacts on Both CARE and Non-CARE Rates Should be Presented

While the White Paper calls out bill differences in hot climate zones as compared with cool or coastal areas, it misses an opportunity to highlight the difference between rates paid by CARE and non-CARE customers. TURN supports and lauds the Commission's strong record on low-income programs which ensure many who would otherwise experience energy insecurity have access to essential electricity services. Unfortunately, many medium income families in California are also challenged by affordability. The combination of high housing costs and the rapid rise in the costs of electricity and other utility services means that families who do not qualify for low-income programs may nonetheless find the cost of electricity unaffordable.

For example, TURN estimates that the system average rate, Non-CARE and CARE rates in 2030 would be 32.9 cents, 37.5 cents and 25 cents respectively. This could result in significant differences in affordability. The California Advocates also called out this issue, which will become increasingly important as this work is used to inform the Affordability Proceeding.

Additional Costs for Wildfire and Clean Energy Infrastructure Should be Included

The CRT tool and forecast methodology is highly reliant on IOU inputs regarding costs that are expected but not yet filed or in rates. This could result in underestimating the out-year spending. If the escalations applied for the forecast of later year rates do not adequately reflect IOU spending trends, rates will be understated. For example, although the *En Banc* model reflects

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[6] PG&E 4Q Earnings Presentation Slide Deck, p. 13: https://s1.q4cdn.com/880135780/files/doc_financials/2020/q4/EC-Q4-2020-Earnings-Presentation-Feb-25.pdf

[7] CEDU 2020 Baseline Forecast PG&E Low Demand Case-Corrected, filed 3/4/21 available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03

[8] This assumes revenues and rate base grow at roughly the same rate. Then, rate growth= rate base growth- sales growth. If rate base growth is 7% consistent with PG&E's forecast as an example, and sales growth is a loss of 1% per year, rates would grow at 8% per year from the 2023 base through 2030.

PG&E's spending through 2022, it does not reflect expected wildfire spending levels for the future. This could well be an oversight considering investor messaging regarding rate base. PG&E is not alone in these projections as SCE projects similar 7% annual rate base growth.[9]

The forecast prepared by Energy Division staff used cost inputs provided by the utilities. In developing the "wildfire" portion of the revenue requirements for PG&E, as shown, for example, in Figure ES-1, staff relied on "the most recently filed WMPs at the time of the preparation of this paper," which were the 2020 WMPs filed in February of 2020.[10] Staff explained that the IOUs could not provide more updated reliable data. As a result, the forecast for PG&E is "consistent with data in its most recent RAMP filing."[11] PG&E's RAMP filing, submitted in June of 2020, forecasts total wildfire spending (expense and capital) of $1.6 billion for 2020, and an average annual wildfire spending for 2020-2026 of $1.8 billion.[12] It is TURN's understanding from Staff that the PG&E rate forecast model used direct cost inputs through 2026 of approximately $2.8 billion per year.

While the Staff forecasting process relies on expenditure estimates from the IOUs, these direct cost estimates represent less than 60% of PG&E's likely wildfire spending. PG&E's 2021 WMP Update, filed on February 5, 2021, shows that PG&E actually spent $4.8 billion in 2020, and forecasts average annual spending of $5.0 billion in each year 2020-2022.[13] There is little indication that wildfire spending will decrease significantly after 2022, as PG&E apparently plans to continue hardening its distribution system in high fire threat areas. Over the course of ten years, the difference between the model inputs and PG&E's more recent forecast thus results in about $22 billion in spending not reflected in the model base case.

The White Paper explicitly recognized the significant uncertainty surrounding costs and noted that comparing projected to actual spending for 2019 (the last full year of data available at the time the White Paper was finalized). This comparison found that IOU spending for 2019 ranged from 19% higher to a whopping 132% higher.[14] In an attempt to address some of the spending uncertainty around future wildfire costs, the White Paper includes a "High Case" analysis which uses a 20 percent adder to the overall base case wildfire revenue requirement.[15] This results in a total of $23.7 billion in costs for PG&E over the forecast period.[16] However, given the pace of recorded IOU wildfire spending, future analysis would benefit from a more complete exploration of the range of wildfire costs.

It is TURN's understanding that Staff had slightly more recent data inputs from SCE and SDG&E, though TURN could not review any of those data to evaluate the accuracy of wildfire cost forecasts. We do note that in the 2021 WMP Update, submitted in February 2021, SCE

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[9] SCE Latest Business Update (Slide Deck), dated Feb. 26, 2021, p. 13: https://www.edison.com/home/investors/events-presentations.html.
[10] White Paper, p. 57.
[11] Id.
[12] See, Attachment A.
[13] PG&E WMP 2021 Update, Table 3-2, included as Attachment B.
[14] White Paper, p. 61.
[15] Id., p. 65.
[16] Id.

forecasts average annual spending of $1.61 billion for 2020-2022,[17] while in its 2020 WMP SCE had forecast spending $1.27 billion per year.[18]

TURN appreciates that spending does not translate directly into revenue requirements, due to the lag between capital expenditures and capital additions, the effect of deferred taxes, and the nature of depreciation. Nevertheless, it is a truism that at some point we will have to pay the piper, so that even if it occurs after 2030, it is very likely that residential rates will rise more than predicted by the White Paper.

Beyond Wildfire costs, additional transmission and storage costs to support California's 2045 Climate and Clean Energy goal are in the tens of billions of dollars.[19] These can be expected to accelerate from 2030 to 2045 resulting in continued high levels of rate base growth and a continued upward trajectory in rates and bills rather than a plateauing after 2030.

Thank you very much for the opportunity to present these comments.

Yours truly,

Marcel Hawiger
Staff Attorney

[17] SCE 2021 WMP Update, Table 3-2.
[18] SCE 2020-2022 WMP, Table 5-2.
[19] "From 2030 to 2045, grid investments of up to $75 billion [California Statewide] will be required to integrate bulk renewable generation and storage and serve the load associated with transportation and building electrification." Pathway 2045, Update to the Clean Power and Electrification Pathway, Southern California Edison, November 2019, p. 7., https://www.edison.com/home/our-perspective/pathway-2045.html

Attachment A

Excerpt from PG&E's 2020 RAMP Report, June 30, 2020

Application: 20-06-
(U 39 M)
Exhibit No.:
Date: June 30, 2020
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2020 RISK ASSESSMENT AND MITIGATION PHASE REPORT

TABLE 10-9
FORECAST COSTS
2020-2022 EXPENSE
(THOUSANDS OF DOLLARS))

Line No.	Mit. No.	Mitigation Name	MWC[(a)]	2020	2021	2022	Total
1	M1	EVM	IG	$494,627	$506,993	$519,668	$1,521,288
2	M5	PSPS	AB, IG	170,699	174,967	179,341	525,007
3	M6	PSPS Impact Reduction Initiatives	IG	225,785	211,198	207,502	644,484
4	M7	Situational Awareness and Forecasting Initiatives	IG	30,229	32,379	31,214	93,822
5	M8	SIPT	IG	23,668	37,057	41,286	102,010
6	M9	CWSP PMO	IG	18,529	19,071	19,625	57,226
7	M10	Additional System Automation and Protection	AT, IG	5,150	130	134	5,414
8		Total		$968,687	$981,795	$998,770	$2,949,252

(a) PG&E is recording costs for certain activities in temporary MWC IG but expects to forecast costs for this work in MWC AB or HN in the 2023 GRC.

Note: See WP 10-1.

TABLE 10-10
FORECAST COSTS
2020-2022 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M2	System Hardening	08W	$366,725	$565,640	$698,360	$1,630,725
2	M3	Non-Exempt Surge Arrester Replacement	2AR	62,448	53,290	–	115,738
3	M4	Expulsion Fuse Replacement	2AP	5,423	5,559	5,698	16,679
4	M6	PSPS Impact Reduction Initiatives	21, 48A, 48D, 49H, 49M, 67D, 94A, 94B	159,701	142,489	123,500	425,690
5	M7	Situational Awareness and Forecasting Initiatives	21A, 49I	13,163	12,371	7,433	32,967
6	M8	SIPT	21A	676	1,152	–	1,828
7	M10	Additional System Automation and Protection	09A, 49T	10,753	17,443	17,772	45,969
8	M11	Remote Grid	49M	4,749	–	–	4,749
9		Total		$623,638	$797,944	$852,763	$2,274,345

Note: See WP 10-1.

TABLE 10-12
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC[a]	2023	2024	2025	2026	Total	RSE[b]	Risk Reduction
1	M1	EVM	IG	$532,660	$545,976	$559,625	$573,616	$2,211,877	2.6[c]	4,156
2	M5	PSPS	AB, IG	183,825	188,420	193,131	197,959	763,334	13.8[d]	16,284[d]
3	M6	PSPS Impact Reduction Initiatives	IG	185,576	141,277	97,011	98,378	522,243	[d]	[d]
4	M7	Situational Awareness and Forecasting Initiatives	IG	30,884	31,656	32,447	33,258	128,245	[e]	[d]
5	M8	SIPT	IG	42,318	43,376	44,460	45,572	175,726	[e]	[d]
6	M9	CWSP PMO	IG	20,116	20,619	21,134	21,663	83,532	[e]	[e]
7	M10	Additional System Automation and Protection	AT, IG	137	141	144	148	570	[e]	[e]
8		Total		$995,515	$971,465	$947,954	$970,594	$3,885,528		

(a) PG&E is recording costs for certain activities in temporary MWC IG but expects to forecast costs for this work in MWC AB or HN in the 2023 GRC.

(b) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(c) The RSE includes the risk reduction for both the Wildfire risk and the Failure of Electric Distribution Overhead Asset risk. See WP 10-3.

(d) The RSE and Risk Reduction score shown on Line 2 (M5 – PSPS) is for the combined M5 – PSPS and M6 – PSPS Impact Reduction Initiatives mitigations.

(e) Foundational mitigation – PG&E does not calculate RSEs for foundational mitigations.

Note: See WP 10-1.

TABLE 10-13
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	M2	System Hardening	08W	$796,320	$850,040	$868,052	$886,390	$3,400,802	7.3[(b)]	17,893
2	M3	Non-Exempt Surge Arrester Replacement	2AR							
3	M4	Expulsion Fuse Replacement	2AP	5,840	6,136	6,289	6,446	24,711	1.0[(b)]	18
4	M6	PSPS Impact Reduction Initiatives	21, 48A, 48D, 49H, 49M, 67D, 94A, 94B	76,375	76,917	77,199	77,487	307,979	(c)	(c)
5	M7	Situational Awareness and Forecasting Initiatives	21A, 49I	7,619	7,810	8,005	8,205	31,639	(d)	(d)
6	M8	SIPT	21A	–	–	–	–	–	(d)	(d)
7	M10	Additional System Automation and Protection	09A, 49T	18,216	18,778	19,247	19,728	75,969	(d)	(d)
8	M11	Remote Grid	49M	–	–	–	–	–		
9		Total		$904,371	$959,681	$978,792	$998,257	$3,841,100		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

(b) The RSE includes the risk reduction for both the Wildfire risk, the Failure of Electric Distribution Overhead Asset risk, and the Third-Party Safety Incident risk. See WP 10-3.

(c) See Table 10-3, Line 3 for the RSE and Risk Reduction score for M6.

(d) Foundational activity – PG&E does not calculate RSEs for foundational activities.

Note: See WP 10-1.

Attachment B

Excerpt from PG&E's 2021 WMP, February 5, 2021

PACIFIC GAS AND ELECTRIC COMPANY

2021 WILDFIRE MITIGATION PLAN REPORT

RULEMAKING 18-10-007

FEBRUARY 5, 2021

3.1 Summary of WMP initiative expenditures

In the Table PG&E-3-1, summarize the projected costs (in thousands) per year over the three-year WMP cycle, including actual expenditures for years passed. In Table 3-2 break out projected costs per category of mitigations, over the three-year WMP cycle. The financials represented in the summary tables below equal the aggregate spending listed in the mitigations financial tables reported quarterly. Nothing in this document shall be construed as a statement that costs listed are approved or deemed reasonable if the WMP is approved, denied, or otherwise acted upon.

TABLE 3-1: SUMMARY OF WMP EXPENDITURES – TOTAL

	Spend in Thousands of Dollars
2020 WMP Planned	$4,829,752
2020 Actual	$4,862,464
Difference[a]	($32,712)
2021 Planned	$4,955,161
2022 Planned	$5,197,811
2020-22 Planned	$15,015,436

(a) Difference represents planned minus actual.

TABLE 3-2: SUMMARY OF WMP EXPENDITURES BY CATEGORY

WMP Category (Spend in $ Thousands)	2020 WMP Planned	2020 Actual	Difference[a]	2021 Planned	2022 Planned	2020-22 Planned (w/ 2020 Actual)
Risk and Mapping	$5,450	$6,300	($850)	$6,841	$7,067	$20,208
Situational Awareness	$36,020	$35,518	$502	$49,789	$63,434	$148,741
Grid Design and System Hardening	$2,624,433	$2,692,241	($67,808)	$2,698,098	$3,017,543	$8,407,881
Asset Management and Inspections	$379,534	$299,737	$79,797	$266,904	$241,097	$807,738
Vegetation Management	$1,454,522	$1,451,311	$3,211	$1,507,398	$1,450,157	$4,408,867
Grid Operations	$179,161	$182,984	($3,823)	$192,059	$180,468	$555,510
Data Governance	$90,975	$116,619	($25,644)	$147,362	$149,992	$413,974
Resource Allocation	$2,148	$6,591	($4,443)	$7,121	$7,179	$20,891
Emergency Planning	$25,107	$22,793	$2,314	$26,341	$27,356	$76,489
Stakeholder Cooperation and Community Engagement	$32,402	$48,371	($15,969)	$53,248	$53,519	$155,138
Total	$4,829,752	$4,862,464	($32,712)	$4,955,161	$5,197,811	$15,015,436

(a) Difference represents planned minus actual.

Pacific Gas and Electric Company (PG&E) provides above the information requested for Table PG&E-3-1 and Table PG&E-3-2. There are several important points to be aware of in the presentation of this information:

- Mitigation and control work has been included in this Wildfire Mitigation Plan (WMP) and these tables that spans multiple cost recovery mechanisms including the General Rate Case (GRC), Transmission Owner (TO) rate case at the Federal Energy Regulatory Commission (FERC), Catastrophic Event Memorandum Account (CEMA), Fire Risk Mitigation Memorandum Account (FRMMA), Wildfire Mitigation Plan Memorandum Account (WMPMA), and EPIC. Some of these costs have already been approved for inclusion in customer rates and some of these costs are still pending review or approval through open and transparent cost recovery proceedings;
- Financial figures have been mapped to each initiative and/or category based upon the activity being described in Section 7.3 of this document;
- While the primary work performed for wildfire risk mitigation is in the HFTD areas, some work and financial costs associated with Non-HFTD areas have been included in some of these the financial figures;
- The costs reflected are PG&E's best estimate of the costs for the proposed programs as of February 5, 2021. Further changes to 2021 budgets and work