Pacific Gas and Electric Company™

Robert S. Kenney
Vice President
Regulatory and External Affairs

P.O. Box 77000
San Francisco, CA 94177-0001
Mail Code B23A
(415) 973-2500
Cell: (415) 407-6692
Robert.Kenney@pge.com

March 19, 2021

Via Email (Ankit.Jain@cpuc.ca.gov; costenbanc@cpuc.ca.gov)

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

SUBJECT: Pacific Gas and Electric Company's Comments on the Draft "Utility Costs and Affordability of the Grid of the Future" White Paper (issued February 16, 2021)

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment on the White Paper and to participate in the Commission's dialogue on this important topic.

We share the State's goal of a safe, reliable, clean and equitable energy future. The safety of our customers and the communities we serve is our most important responsibility, and we recognize we must take bold action now to help California achieve these goals.

We thus welcome and support the Commission's efforts to examine how utility costs will shape our energy future. Our commitment is to keep customer costs as low as possible, while meeting our responsibilities to safely serve our customers. Our changing climate both presents new risks for our operations, while also proving the imperative of promoting greater use of clean and renewable electricity.

Below, we offer some general comments on the themes discussed at the Commission's En Banc Hearing on February 24, 2021. We also provide some specific comments on the Commission's White Paper presented at the En Banc.[1]

I. General Comments

The Commission and the Investor Owned Utilities (IOUs) play a critical role in implementing California's ambitious climate goals, which have been incorporated into a variety of initiatives such as the Renewable Portfolio Standard and Energy Efficiency programs. As highlighted in the White Paper, the costs of these programs are already substantial, likely to grow over time, and necessary for the State to reach its climate goals.

In addition to the carrying the costs of climate and equity initiatives, the utilities are also facing rising costs from the effects of climate change. California faces an increasing threat from catastrophic wildfires, severe weather and higher temperatures. Prolonged periods of high temperatures, extreme dryness, tinder-dry grass and record-high winds -- combined with vast tree mortality following a historic five-year drought -- are increasing the number of wildfires and making them more dangerous.

---

[1] "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates and Equity Issues Pursuant to P.U. Code Section 913.1" (February 2021) (the "White Paper").

Meanwhile, the seas are rising, which poses risks to utility infrastructure, and snowpack is declining, which threatens hydroelectric resources.

These challenges are unprecedented. The costs of addressing these challenges are unavoidable. There is no doubt that utilities will play a central role in California's energy future, with transmission and distribution (T&D) assets required to support renewable energy expansion, the storage that will be paired with renewables, and the push toward electrification.

While the size of the challenge is new, we have learned many lessons from our past that will help the State rise to the challenge. The California Alternate Rates for Energy (CARE) Program is, in part, a recognition that bearing costs must be shared equitably and in a way that is progressive with respect to income. CARE will not be enough, however, to address our equity issues. The Commission is rightly seeking to expand its efforts to take a more systematic and holistic approach to addressing equity issues. This will be achieved by expanding beyond the piecemeal attempts to compensate small, selected populations, both low-income and non-low-income, with large subsidies to address inequities already in place. PG&E supports the idea of looking beyond traditional utility and regulatory approaches to address the equity challenge.

As acknowledged by experts at the En Banc, the benefits of achieving climate and environmental goals reach beyond the energy utilities, and California should look for all options to achieve these goals in an affordable manner for all Californians. At the En Banc, panelists recognized the limits of the energy bill in addressing the equity challenges presented by these costs. The panelists rightly recognized that using the energy bill to achieve these goals can penalize lower-income customers and drive customers away from electricity use at the very time we need to promote the use of clean electricity.

PG&E was encouraged by ideas from the panelists who sought non-traditional and, in some cases, non-energy-bill funding of costs and benefits that go beyond customers' roles as energy consumers. These other sources of funding, like taxes, hold the promise of a more progressive source of funding than can occur through volumetric energy rates. PG&E is looking forward to engaging with stakeholders to explore creative solutions to keep costs and rates affordable and to explore these new approaches to costs and rates.

Some of the ideas that emerged in the En Banc, such as regional pricing, pricing for T&D assets tied to locational risk, progressive flat-rate components, rate design approaches that preserve marginal pricing, tax funding of energy bill components, and decision-making that would expand to include more non-energy-industry and climate-affected parties, are intriguing and need further exploration. Most importantly, PG&E was encouraged to hear the En Banc's vision of environmentally sound and equitable programs funded in a broader and more equitable way. We look forward to supporting this vision however we can.

II. Specific Comments on the White Paper

A. Transportation Electrification

PG&E is a strong supporter of California's clean energy policy goals, including transitioning the transportation sector from fossil fuels to cleaner fuels, such as electricity. The transportation sector continues to be California's largest source of greenhouse gas (GHG) emissions while the GHG emissions from the generation of electricity continues to decrease. Transportation electrification (TE) therefore offers great potential to reduce GHG emissions.

IOUs play a key role in the transition to electric vehicles (EVs) by providing access to infrastructure (via specific programs as well as "duty-to-serve" investments), lowering total cost of vehicle ownership (via EV rates and rebate programs funded by non-customer sources), increasing customer education and undertaking outreach to aid in customers' understanding of the benefits of TE (e.g., acting as a trusted energy advisor to customers seeking to learn more about transitioning to EVs), and grid modernization (e.g., through innovative vehicle to grid (VGI) studies and pilots).

PG&E appreciates the White Paper's reference to the recent California Energy Commission (CEC) AB 2127 Assessment on charging infrastructure need.[2] Specifically, the AB 2127 assessment found that there are fewer than 200,000 public and shared private charging ports deployed today and the assessment estimates a need of approximately 1.5 million charging ports by 2030 to put the State on the path to hitting Governor Newsom's light duty vehicle Executive Order goals. The AB 2127 assessment highlighted the need for continued, near-term public and customer support to roll-out EV charging infrastructure while also cautioning that public and customer funding cannot be the only solution given the scale of charging infrastructure needed. PG&E believes customer funded programs have played and should continue to play an integral part in aiding the development of charging infrastructure necessary to give transportation users confidence needed to switch to an electric vehicle. In the future as markets develop and private investment increases, PG&E believes that public and customer funded support can be focused on market segments that may not be broadly served by private third-party providers, such as charging in multi-unit dwellings within disadvantaged communities.

PG&E agrees with the White Paper's modeling outputs that demonstrate a minimal impact to customer rates from a hypothetical level of future utility customer funded TE programs based on "an examination of the impact of current programs on rates, and a simple doubling of program spending the latter half of the decade."[3] For PG&E, the White Paper estimates the transportation rate embedded in baseline bundled residential rate forecast to be $0.001/kWh each year from 2021-2030 compared to an overall bundled residential rate of $0.266 in 2021 which rises to $0.329 in 2030.[4]

PG&E appreciates the White Paper's discussion of the potential for downward pressure on utility rates and agrees that increased TE offers the potential to lower electric rates for all utility customers as the fixed costs associated with providing utility service will be spread over a greater amount of kWh used to charge vehicles. A prior study conducted by Synapse Energy looked at the contribution of EV charging to PG&E revenues from 2012 and 2018 as compared to the cost of EV programs and distribution upgrades. The study found that on PG&E's electric grid EVs contributed around $350M more than the cost (including programs, transmission, distribution, capacity, and generation) over that period.[5] The benefit from EVs rises to $600M from 2012-2018 when SCE's service territory is added.

---

[2] Ibid., pp. 65-66.
[3] Ibid., p. 66.
[4] Ibid., Table 26, p. 68.
[5] Synapse Energy Study is available here: https://www.synapse-energy.com/sites/default/files/EVs-Driving-Rates-Down-8-122.pdf

In addition, PG&E agrees with the White Paper's findings that significant overall customer energy cost savings can be derived from moving from an internal combustion engine (ICE) vehicle to an EV due to the latter vehicle type's lower total cost of ownership via lower fueling and maintenance costs.[6] The paper cautions that "households that cannot afford the upfront costs associated with electrification will miss out on these cost savings."[7] While it is true that EVs have generally been more costly on an up-front basis over the recent past, continued battery cost declines[8] combined with auto manufacturers announcing new and cheaper models[9] point to a near future where EVs will not only be less costly to operate but also less costly on an upfront purchase price basis. Furthermore, California IOUs continue to fund EV rebates[10] via Low-Carbon Fuel Standard Credit (LCFS) revenues and PG&E intends to propose an LCFS funded used EV rebate, with an additional rebate amount for low-income customers, later this year.

PG&E firmly believes that TE offers a "win-win-win" scenario whereby GHG emissions, electricity rates, and total customer energy costs can all be reduced. To enable such a scenario, PG&E urges the Commission to adopt a final TE investment framework in Rulemaking (R.) 18-12-006 that allows IOUs the needed flexibility to quickly roll out supportive programs that are necessary to help spur the nascent EV market forward.

B. Net Energy Metering

PG&E appreciates the White Paper's section on Net Energy Metering (NEM) and highlighting some of the issues with the existing program structure. As the White Paper points out, the Commission conducted a study to assess the current NEM tariffs. This "Lookback Study"[11] found that current NEM tariffs are not cost-effective for all customers or for the electric system. The current NEM tariffs continue to shift costs from participating customers to non-participating customers. The current estimated cost shift for the three IOUs under the existing NEM paradigm is approximately $3.0 billion and is projected to rise to $5.0 billion by 2030.

The White Paper also pointed out the inequities contained in the current NEM paradigm, both the particular impact it has on low-income customers, as well as the overall problem of a large subsidy borne by one group of generally less affluent customers to benefit a more affluent group. The White Paper appropriately captures both of these phenomena. It also stresses the current Commission effort to address the current inequities and to achieve the Legislative direction in AB 327 to achieve sustainable growth and a balance of benefits and costs.

---

[6] White Paper, pp. 79-80.
[7] Ibid., p. 86.
[8] https://www.bloomberg.com/news/articles/2020-12-16/electric-cars-closing-in-on-gas-guzzlers-as-battery-costs-plunge
[9] https://www.businessinsider.com/best-cheap-affordable-evs-electric-vehicles-tesla-nissan-ford-mustang-2021-2
[10] https://cleanfuelreward.com/
[11] Net Energy Metering 2.0 Lookback Study, January 21, 2021. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467448

Finally, for NEM and other Distributed Energy Resources, PG&E appreciates the Commission's recognition of the impact that these programs have on affordability. When DER programs are not cost-effective, the rate impact can result in inequities and the cost shift from participants to nonparticipants should be limited without strong policy reasons to justify their continuation. For example, there is a strong policy to protect low-income customers -- as was recognized by the Commissioners in the En Banc – that lies behind the IOU and Commission commitment to CARE rate subsidies. Where there is no such strong policy motivation, there should be limitations on programs that are not cost-effective. PG&E recognizes and supports, for example, the strong commitment by the Commission in the Microgrid OIR to ensure the statutory direction to prevent cost-shifts when establishing tariffs or contracts for microgrids.

C. Capital Costs and Capital-Related Revenue Requirements

The provision of electric and gas service requires the acquisition and construction of assets that can provide service to customers over many decades before becoming needing to be replaced. Rather than have customers pay the entire cost of these assets in the year they are acquired, utilities finance these assets by issuing debt and equity to investors. Rate base represents the amount of money investors have currently invested at any point in time. Over time, investors are paid back their money from the depreciation expense that is included in the cost of service paid by customers. Customers also pay investors for the use of the investors' money – interest on debt, and return on equity (ROE), which together are called the cost of capital.

The adopted ROE does not guarantee any level of profit, but provides utilities with the opportunity to earn a reasonable profit to compensate shareholders for the use of their money. Utilities can only earn a profit if they can manage their total costs, capital costs as well as operating and maintenance (O&M) costs, to be sufficiently less than the revenue requirement set by the Commission in order to earn a profit (i.e., the "earned" ROE). Thus, investing in assets that are not needed or are not reasonable, runs the risk of disallowances that reduce profits and the earned ROE. This is contrary to the assertion in the White Paper that utilities have the incentive to drive increases in rate base to earn a higher profit.[12] In fact, utilities do the opposite: by minimizing investments they may have lower overall dollar amounts of profits, but if they can successfully manage costs then they may improve their opportunity to earn higher earned ROEs or profits, and it is the latter that drives the value of the company.[13] Simply put, utilities do not need to make higher levels of investments to make higher profits.

The profits earned by IOUs are not just compensation to investors for the time value of their money, but also compensate them for bearing risk. The interest rate paid to utility bondholders also reflects the

[12] White Paper, p. 24. The White Paper cites the widely misunderstood "Averch-Johnson effect". Averch and Johnson, two economists writing in the 1950s, hypothesized that if utilities were authorized a cost of capital higher than what was actually needed to compensate investors, then utilities would have a tendency to favor capital solutions rather than non-capital solutions. Averch and Johnson demonstrated this mathematically using a number of assumptions, but offered no empirical evidence in support of their hypothesis. Relaxing their assumption that regulators adopt a cost of capital higher than necessary results in the opposite conclusion – that utilities would have a preference for non-capital solutions.

[13] Aside from the lack of incentive to over invest, utility capital investments are highly scrutinized in various rate proceedings to ensure they are necessary and are cost effective, removing the opportunity to invest in unneeded capital.

risks borne by those investors. Generally, the greater the risk, the higher the overall cost of capital. Since the cost of financing rate base is a function of the risks and the cost of capital, reducing utility risks can reduce the cost of capital. In California, climate change has also led to more extreme weather events creating even more risk borne by utilities. As a result, the cost of capital is higher in California relative to utilities in other states.

The Commission has some discretion over the rate of growth of rate base through the depreciation rates it approves for the utilities, although the resulting impact on customer rates is moderated by other drivers of customer rates.[14] Rate base growth is a function of two parameters – the rate at which capital is added to rate base, and the rate of depreciation of the assets. Rate base growth can be slowed, or even eliminated, by increasing the depreciation rate. Although doing so would increase customer rates in the short term, in the long term it has the effect of reducing customer rates. Historically, consumer advocates have shown a preference for lower depreciation rates, a preference generally reflected in Commission decisions, and hence the consequent higher growth rate of rate base.

D. Rate and Bill Trajectory

PG&E appreciates and shares the White Paper's focus on providing affordable energy to California residents and businesses. While the long-term trajectory of PG&E's rates and bills is uncertain, providing a forecast that extrapolates recent and emerging trends into the future has facilitated a productive discussion around how to maintain access to affordable energy in California. When discussing long-term rate trajectory, it is important to acknowledge the uncertainty of these projections which the White Paper has done in multiple locations and even more explicitly by providing two rate scenarios related to wildfire mitigation costs.

PG&E would like to reiterate the significant uncertainty in the long-term rate projections presented in the White Paper.

First, there is significant uncertainty around the long-term revenue requirements. For example, the White Paper assumes that the future costs related to wildfire insurance and catastrophic events that would be in rates in 2023 through 2030 follow the average costs requested in applications over the last three years (2018 through 2020).[15] While this is a reasonable assumption given the limited information currently available, there is significant uncertainty around these projections. Additionally, a significant portion of the wildfire related revenue requirements requested in applications over the past three years are not yet approved by the Commission. Since these revenue requirements are not yet approved, it is uncertain what the total wildfire related revenue requirement effective in rates will be even prior to 2023.

Second, there is significant uncertainty around the long-term electric sales forecast. Beyond 2023, the White Paper relies on the CEC's residential sales forecast and makes additional assumptions to split this forecast into a *bundled* residential sales forecast to calculate average bundled residential rates. With new policies and regulations being passed regarding electric vehicle sales requirements and targets for

[14] The revenue requirement of rate base has for many decades comprised about one-third of the total cost of providing electric service, meaning that rate base has been growing at the same rate as other utility costs that comprise the total revenue requirement.
[15] White Paper, p. 59.

electric vehicles in 2030, there is a potential for electric vehicle sales and associated electric consumption to increase to meet these targets. These new targets may not be fully reflected in the CEC's 2020 Integrated Energy Policy Report (IEPR) California Energy Demand (CED) Forecast used to develop the rate forecasts in the White Paper. In addition, there is the potential for an increase in electric sales resulting from building electrification which is not currently reflected in the CEC's 2020 IEPR CED Forecast. PG&E recognizes the opportunity for an increase in electric sales resulting from transportation and building electrification to mitigate the rate impact of future revenue requirement increases.

Additionally, PG&E appreciates the White Paper deliberately presenting energy bills for customers in hot climate zones. As the White Paper highlights, energy bills vary within a given IOU territory based on factors including CARE assistance eligibility, climate zone, building type, electric rate option, etc.[16] Fundamentally, residential bills in hot climate zones are significantly higher than the average customer bill because those customers tend to use more electricity and nearly all residential electric revenues are collected through volumetric rates. However, the cost of providing electric service to residential customers has both fixed and variable elements. For example, the costs of various processes such as printing and mailing bills, or installing and maintaining poles, do not vary with a customer's monthly kilowatt-hour (kWh) usage. PG&E incurs these costs each month even if a customer uses no electricity at all. The Commission has recognized this fixed-variable principle, both in D.15-07-001[17] and in many decisions over the years approving fixed charges for non-residential customers.[18] However, to date, the Commission has not approved a fixed charge for any of PG&E's residential rate schedules. Instead, nearly all costs have been collected through volumetric energy charges. This rate design inflates the volumetric charges significantly above variable costs, is not cost-based, and results in low users not paying their equitable share of the fixed costs they impose on the system, with high users paying an unfairly high share of those costs and facing greater bill volatility. PG&E encourages the Commission to consider a cost-based fixed charge for residential customers which would not only better represent cost causation, but also reduce the volumetric rate to mitigate the current disincentive for customers to convert existing end uses to all-electric. This would contribute to GHG emission reductions and help to mitigate future rate increases by increasing electric sales.

Finally, PG&E is pleased to see the Cost and Rate Tracking (CRT) tool being used to produce the rate analyses presented in this White Paper.[19] PG&E has appreciated working collaboratively with the Energy Division to develop the CRT and looks forward to continue collaborating with the Energy Division in the future to refine the functionality of the tool.

E. Historical Transmission Costs

PG&E acknowledges the Commission's brief review of historical transmission costs in Section 2.6 of the White Paper. This section highlights the fact that the Transmission Access Charge (TAC) has been

---

[16] White Paper, p. 73.
[17] D.15-07-001, pp. 189-190, 209-212.
[18] All of PG&E's non-residential rates include monthly fixed charges to help cover at least a portion of PG&E's fixed costs. See also, D.15-07-001, pp. 194- 196.
[19] The CRT was created as a result of D.20-07-032 in Rulemaking 18-07-006 (Affordability OIR) and is intended to provide increased transparency to assist the Commission in assessing affordability.

increasing while the total annual gross load has been declining[20] and then continues to select and display certain trends or data points that present a rather incomplete picture. It is important to point out that the term "gross load" is a measure of all energy delivered for the supply of end-use customers.[21] The transmission system supports customers' ability to generate their own energy and interconnect a staggering amount – over 6 GW - of distributed renewable generation to PG&E's system. This is an impressive accomplishment for California and yet the metric "gross load" does not accurately capture the increase in complexity of the grid whereby hundreds of thousands of customers utilize the grid as a battery exporting surplus energy onto the system when the sun is shining and drawing energy from the grid after the sun sets. The growth of rooftop solar and other forms of DG would surely drive down gross load. For this reason, PG&E encourages the Commission to also evaluate how TAC has performed relative to "total energy consumption" or total energy demand by customers, inclusive of rooftop solar and other forms of distributed generation. Also, it is important to point out that the growth of distributed generation has led to what the CAISO has coined as the "Duck Curve"[22] which presents new challenges for the transmission system, specifically requiring fast and flexible ramping resource capabilities with the ability to start and stop multiple times per day to reliably operate the grid. PG&E believes acknowledgement of total energy consumption versus "gross load" as well as representing how the transmission system must adapt to accommodate the Duck Curve would be productive additions to the section assessing historical transmission costs.

In addition, PG&E believes the White Paper can be strengthened by adjusting how data is displayed in this section. First, the White Paper compares costs over a 5-year period and then shares percentage increase metric over that period (2016-2021)[23]. A more balanced way to show such statistics would be to use year-over-year increases. For example, the White Paper reads "…from 2.14 billion to a forecasted capital addition of $2.59 billion in 2021, an approximately 21 percent increase."[24] This 5-year ~21% increase is equivalent to a ~3.9% annual increase for each of the 5 years. Second, the White Paper makes a statement implying that the average age of a transmission asset is 36 years.[25] This is not a very helpful statement given the fact that there are a multitude of different types of assets (e.g. steel towers, wood poles, protection schemes, circuit breakers, conductors, etc.) each with different expectations for years of useful life. Lastly, SDG&E, SCE and PG&E's transmission systems are quite different in terms of scale, terrain, system needs, risk and number/types of customers served. The White Paper seems to imply through comparative statements and tables that the three California IOUs should all have more similar expense data as well as break-downs between CAISO-approved and self-approved projects. The White Paper should seek to incorporate and better understand the differences between the three transmission systems and add statistics and specifications to demonstrate how these systems are alike and different. Doing so, will help contextualize the financial information shared in this section as well as strengthen the White Paper.

[20] White Paper, p. 35.
[21] Ibid., p. 39.
[22] https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf
[23] White Paper, pp. 36-37.
[24] Ibid., p. 37.
[25] Ibid., p. 37.

III. Conclusion

PG&E shares the State's goal of a safe, reliable, clean and equitable energy future. The safety of our customers and the communities we serve is our most important responsibility, and we recognize we must take bold action now to help California achieve these goals. PG&E appreciates the opportunity to provide comments on the Commission's White Paper and En Banc and looks forward to exploring different solutions with the Commission and other parties.

Respectfully yours,

/s/ Robert Kenney
Vice President
Regulatory and External Affairs

cc: Service Lists -- R.18-07-006, R.18-12-006, R.19-01-011, A.19-09-014, R.12-06-013, R.20-01-007, R.20-07-013, R.18-07-005, R.19-03-009, R.19-01-006, R.17-06-026, R.19-10-005, A.18-12-009, A.19-08-013, A.17-10-007, A.18-12-001, A.18-04-002, A.17-05-004, A.19-03-002, A.19-11-019, A.20-10-012, A.20-07-004, A.20-07-002, A.20-04-014, A.19-07-007, A.19-08-002, A.20-02-003, R.19-07-017, A.19-07-020, A.19-11-003, A.20-03-014, R.20-08-020, R.14-07-002, R.20-08-022, A.20-09-019, A.20-06-012, R.21-02-014