PUBLIC UTILITIES COMMISSION
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Pacific Gas & Electric Company
ELC (Corp ID 39)
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Subject: Rate Structures for Vehicle Grid Integration Pilots

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STATE OF CALIFORNIA **GAVIN NEWSOM,** *Governor*

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From: Energy Division PAL Coordinator

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September 2, 2022

Advice 6694-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: Rate Structures for Vehicle Grid Integration Pilots

Purpose

To submit rate structures pursuant to CPUC Resolution E-5192 to propose rate structures for Phase II of residential and commercial fleets pilots.

Background

Senate Bill 676 (Ch. 484, Stats. 2019) (SB 676) enacted new Public Utilities Code Section 740.16. Section 740.16 requires the California Public Utilities Commission (CPUC) to establish strategies and quantifiable metrics to maximize the use of feasible and cost-effective electric vehicle (EV) integration into the electrical grid (Vehicle Grid Integration, or VGI) by January 1, 2030. On December 21, 2020, the CPUC issued D.20-12-029 implementing SB 676 in Rulemaking (R.) 18-12-006. Among other things, D.20-12-029 adopted various strategies to promote VGI and ordered PG&E and other investor-owned utilities to implement various near-term policy actions that the CPUC has found reasonable in support of the strategies.

On May 5, 2022, the CPUC issued Resolution E-5192 that approved with modifications, three VGI pilots proposed in Advice Letter 6259-E. Each of these pilots will begin in 2022 and will run for three years.

Pilot #1 – V2X Residential Pilot Program Residential V2X pilot program targeted at spurring the adoption of bidirectional light-duty vehicles (LDVs) at single-family homes through customer incentives. $7.5 million

Pilot #2 – V2X Commercial Pilot Program Commercial V2X pilot program targeted at spurring the adoption of bidirectional medium- and heavy-duty vehicle (MHDV) fleets through customer incentives. $2.7 million

Pilot #3 – V2M PSPS Microgrid Pilot Vehicle-to-Microgrid pilot aimed at enabling Behind-the-Meter bidirectional electric vehicles in PSPS-formed microgrids to support community resiliency. $1.5 million

Ordering Paragraph 6 of Resolution E-5192 also directs PG&E to file a Tier 2 advice letter within 120 days proposing "rate structures for phase II of the residential and commercial fleets pilots. This advice letter shall include both dynamic and static TOU rate structure."

Summary of the VGI Pilots' Real Time Pricing Rate Design

The real-time pricing (RTP) rate for the VGI pilots will use a number of elements from PG&E's RTP rate developed in its General Rate Case (GRC) Phase II[1] as well as the CalFUSE model[2], with a couple of modifications. The main characteristics of the rate include:

- A day ahead hourly generation rate equal to the marginal energy costs (MEC) and marginal generation capacity costs (MGCC) approved in D.21-11-016. This is equivalent to the Day Ahead Hourly RTP (DAHRTP) rates approved in D.22-08-002 without the revenue neutral adder (RNA).
- A day ahead hourly distribution rate designed to recover the Primary Distribution Capacity Costs approved in D.21-11-016. The hourly prices will vary depending on the location of the customer and utilize the scarcity pricing concept, with prices dependent on the forecasted load on a representative circuit with similar load characteristics to the customer's circuit.
- A transmission rate equal to the transmission rate on the customer's otherwise applicable tariff (OAT).
- A subscription component that collects revenue equal to the OAT rates applied to a predefined, customer-specific load profile. This component helps protect the customer from bill volatility caused by the RTP as well as ensuring that PG&E can collect its fixed costs and non-bypassable charges (NBCs).

Generation Real Time Pricing Rate Design

The generation portion of the RTP rate will be a day ahead hourly rate that consists of the marginal cost portions of PG&E's DAHRTP rate approved in D.22-08-002. Specifically, it will contain:

1) A Marginal Energy Cost (MEC) equal to hourly forecasts of DA energy prices in dollars per megawatt hour or cents per kilowatt hour (kWh) at the PG&E Default Load Aggregation Point, adjusted to account for losses.

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[1] A.20-12-011 approved in D.22-08-002.
[2] *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation*, Energy Division White Paper and Staff Proposal, June 22, 2022.

2) A Marginal Generation Capacity Cost (MGCC) annual value approved in D.2111016 and D.22-08-002. The allocation of the annual MGCC to various hours will be determined based on the MGCC Study, which is Exhibit (PG&E24) in PG&E's 2020 GRC Phase II, as well as Exhibit (PG&E25), the Stipulation on MGCCs.

These components will make the VGI Pilots' generation RTP rate equal to the DAHRTP rates with the exception of the Revenue Neutral Adder (RNA). As the RNA is used to collect fixed generation costs, it is not needed in the VGI Pilots' RTP rate because the fixed costs will be collected in the subscription component, described below. One advantage of using only marginal costs for the RTP signal is that the marginal costs do not depend on rate schedule and PG&E can develop more universal rates for a wider variety of customers. This holds true for distribution as well as generation. This generation rate will be applicable to bundled customers only. Unbundled customers that are on this rate will receive a generation rate from their load serving entity and the other components of the RTP rate from PG&E.

<u>Bundled vs Unbundled Customers</u>

Approximately 30% of PG&E customers are bundled and receive both generation and distribution from PG&E while the remainder are all unbundled in that they receive generation from a Community Choice Aggregator (CCA). CCAs do not currently offer a dynamic rate option. Further complicating matters is the fact that a higher percentage of EV owners are located in areas that offer a CCA as an option. Thus, the total pool from which users could opt into the dynamic rate would represent significantly less than 30% of all PG&E customers.

Given the risk that the representative sample of pilot participants that choose the dynamic rate may be small, PG&E will elicit participation from CCAs. The ability to invite CCA customers to participate will depend on several efforts:

- PG&E will reach out to CCA stakeholders to share about this opportunity and what it would offer to CCA customers and the CCA as a whole
- If PG&E is successful at gaining CCA stakeholder buy-in then the CCA will need to present the opportunity to its board of directors to vote on this option.
- CCAs that wish to participate will need come to an agreement on how to effectuate. Potential options could include having PG&E compensate their customers (and invoice the CCA for the amount) or having PG&E inform the CCA of how much they owe their customer so that they can directly compensate them.

Distribution Real Time Pricing Rate Design

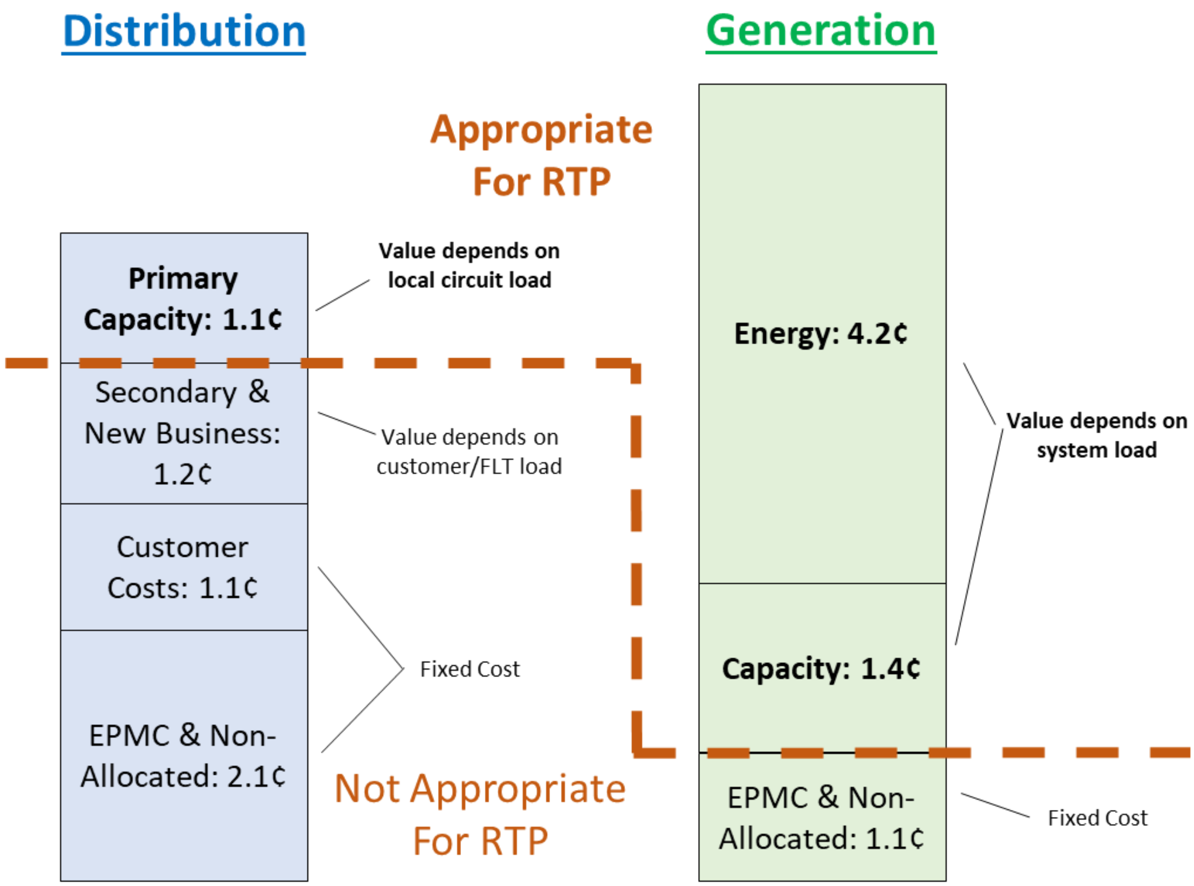
Distribution Capacity Costs and Appropriate Cost Drivers

Distribution is fundamentally different from generation because the cost drivers for each are completely different. Distribution costs are largely fixed, and the remaining variable costs depend only on the capacity requirements at the customer/final line transformer (FLT) level or at a circuit level – there are no costs that vary with energy usage. Generation, on the other hand, has a lot of pure energy costs, plus some capacity costs at the system level, with relatively few fixed costs.

This means that the value in the real time price (RTP) comes almost entirely from generation. There is some distribution grid benefit that can be captured from local grid conditions, but it is much smaller than the generation benefit.

Below is an illustration of those differences based on data from PG&E's 2020 GRC Phase II, using revenue requirements from that time (May 1, 2020). Costs are converted to a cents/kWh figure for comparability; this does not imply that an energy charge is appropriate for all these costs.

Figure 1: Average Non-NEM Costs for Distribution and Generation (Cents per kWh)



Generation is comparatively easy to create a real time price for – the rates can be set at a system level and because the price can be set per hour, capacity charges can be converted into energy without a loss of cost-causation. Equal Percent of Marginal Cost (EPMC) multipliers and non-allocated costs would ideally be collected through a fixed charge but are currently collected in a flat (or TOU varying) kWh adder in the RNA.

Unfortunately, distribution has many more complexities when trying to design an RTP rate. First, Primary Capacity costs have a cost driver that is dependent on the load on the customer's circuit.[3] Because circuits typically serve thousands of customers, the circuit load is fairly independent of any one particular customer's load patterns. Therefore, circuit-level forecasts can be developed and RTP prices can be developed from that forecasted circuit load profile. However, even though circuit forecasts are developed for distribution planning purposes, developing the rates associated with each circuit is not

[3] For more details on the different kinds of distribution marginal capacity costs, see PG&E's testimony in its 2020 GRC Phase II case, Exhibit (PG&E-2) Chapter 7.

easy. PG&E has over 3,000 circuits in its service territory, which would ideally require deriving 3,000 separate RTPs based on 3,000 different forecasts of distribution capacity planning needs. Further, as demonstrated in the Distribution Resources Plan (DRP) proceeding and Distribution Deferral Investment Framework process, the distribution capacity planning needs for a given circuit often change within a 2 to 5 year horizon. Thus, any rate that is developed based on the forecast would likely not reflect the actual primary capacity costs if not refreshed frequently. Additionally, circuit-level forecasting models are not as robust as system-level forecasts, leading to larger forecast errors.

Secondary Capacity costs and New Business Primary costs are for distribution equipment that is much closer to the customer. The cost driver for these components is load at the customer's Final Line Transformer (FLT), which in many cases is just a single customer's load. In order to make a cost-based RTP rate for these components, that rate would essentially have a price that is dependent on the customer's own load – in other words, a demand charge. Therefore, it is not possible to have cost-based day ahead prices created for these components as there is nothing for the customer to react to. Unlike generation, these capacity charges cannot be converted to hourly prices since the high-priced hours are simply the hours in which the customer itself uses the most electricity. If a customer shifts their peak load to another time of day, the costs are still there and are simply allocated to the shifted load. This is why many cost-based rate designs use non-coincident demand charges; they are the best tool to reflect the costs that customers put on the system - and they do not depend on the time of day. These costs are not appropriate to be included in an RTP rate.

BTM DERs also require additional equipment to maintain grid reliability, an additional component of FLTs. High-Penetration PV has already resulted in the impacts of overload, over-voltage, reverse power flow, and system protection[4] to the distribution grid. The protection equipment cost is dependent on export capacity authorized at the time of interconnection and is specific to when the RTP rate is trying to incentivize the customer to export to the grid. Again, allocating these costs appropriately may reduce the value proposition for behind the meter (BTM) DER, but they are in fact reflective of utility costs.

Finally, Distribution Customer Costs, the EPMC multiplier, and non-allocated revenues are all fixed costs that do not depend on customer usage and are therefore also not appropriate for an RTP rate. PG&E believes that a cost-based rate does not EPMC scale the RTP price signal. When a customer uses an extra kWh of energy, the added cost to the utility is just the marginal cost, not the EPMC scaled cost. If the customer reduces load because of an EPMC-scaled signal, the utility loses more revenue than it saves in costs. EPMC scaling of price signals therefore creates a cost shift.

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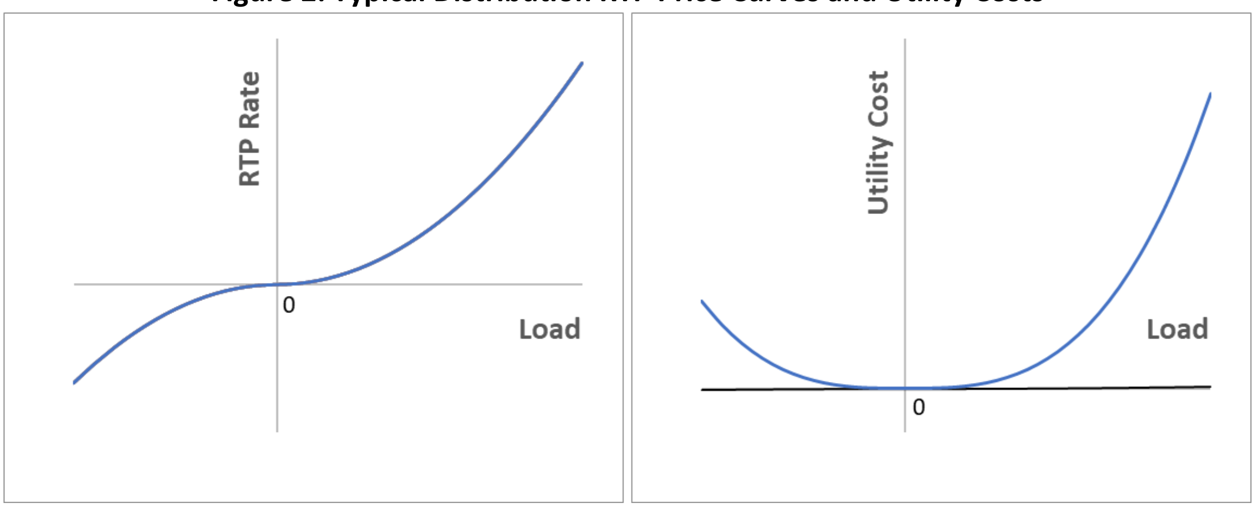
[4] NREL - High-Penetration PV Integration Handbook for Distribution Engineers (ttps://www.nrel.gov/docs/fy16osti/63114.pdf)

Additionally, the use of a subscription base (described below) eliminates the need to scale up rates to collect the full RRQ, so the RTP signal is free to represent only marginal costs and won't change with RRQ changes. PG&E notes that in the settlement agreement for RTP approved in D.22-08-002, multiple intervening parties met and discussed cost-causation for about a year, over 30 separate settlement discussions. The final consensus from that intensive collaboration was that the best RTP signal does not include EPMC scaling.

<u>Distribution RTP Price Curves</u>

The CalFUSE framework provides an example of how distribution RTP rates can be designed. Under CalFUSE, the RTP prices in each hour are derived using "scarcity pricing" where the price increases with higher demand on the grid, encouraging conservation during times of grid stress. The charts below illustrate how these price curves typically look, as well as how that relates to the utility's cost.

Figure 2: Typical Distribution RTP Price Curves and Utility Costs



The utility's cost for the circuit depends on the load on the circuit, but it doesn't matter which direction the electricity flows. If there is a large amount of on-site generation so that the overall load is negative (net exporting) then that has a local distribution cost (not a benefit), and that cost gets higher with additional exports. This is modeled by inverting the price signal when the load on the circuit is negative. During typical conditions when the circuit load is positive, the RTP price is positive (consumption is charged and exports receive a credit). However, during the rare circumstances when the entire circuit has negative load, the RTP price becomes negative (such that exports are charged and consumption is credited). This incentivizes the correct behavior because during these times additional exports increase circuit costs.

The above price curves are one way of allocating Distribution Primary Capacity costs based upon circuit load. One could theoretically design a similar RTP rate for Secondary and New Business costs, but they would be dependent on load <u>at the FLT</u>, not load at the circuit. Unfortunately, as mentioned in the prior section, FLT load is usually just the customer's own load and therefore not something that can be forecasted to give an RTP signal.

Given this limitation and the fact that the Resolution prohibits demand charges, PG&E sees three options regarding Secondary and New Business marginal costs in an RTP rate:

1. Include Secondary and New Business marginal costs with the Primary Capacity costs and model them as if they all varied by circuit load.
2. Treat Secondary and New Business as marginal costs, but ones that don't vary by circuit load (i.e., a fixed $/kWh adder).
3. Treat Secondary and New Business costs as non-marginal so that they are only collected through the subscription mechanism.

Option 1 is the way distribution rates were designed for the Valley Clean Energy RTP pilot.[5] However, that pilot was implemented with limited time to design the rates, and after further consideration and analysis, PG&E does not believe this option is optimal. The main reason for this belief is that FLT load is often poorly correlated with circuit load. This is because FLTs typically only serve a small number of customers (or even a single customer) and therefore have load profiles much more sensitive to specific customer loads, compared to the circuit-level load which reflects the diversity of all customers on the circuit. To illustrate this, Figure 3 below plots the Peak Capacity Allocation Factor (PCAF) hours[6] against FLT hours[7] for a sample circuit.

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[5] PG&E Advice Letter 6495-E-A.

[6] PCAF hours are hours in which the circuit-level load is 80% or more of the circuit's annual maximum load. Figure 3 plots 193 PCAF hours for the sample circuit.

[7] FLT hours are hours with the maximum annual FLT load. Figure 3 plots the peak hours of 86 FLTs on the sample circuit.

Figure 3: Comparison of PCAF and FLT Hours for a Sample Circuit

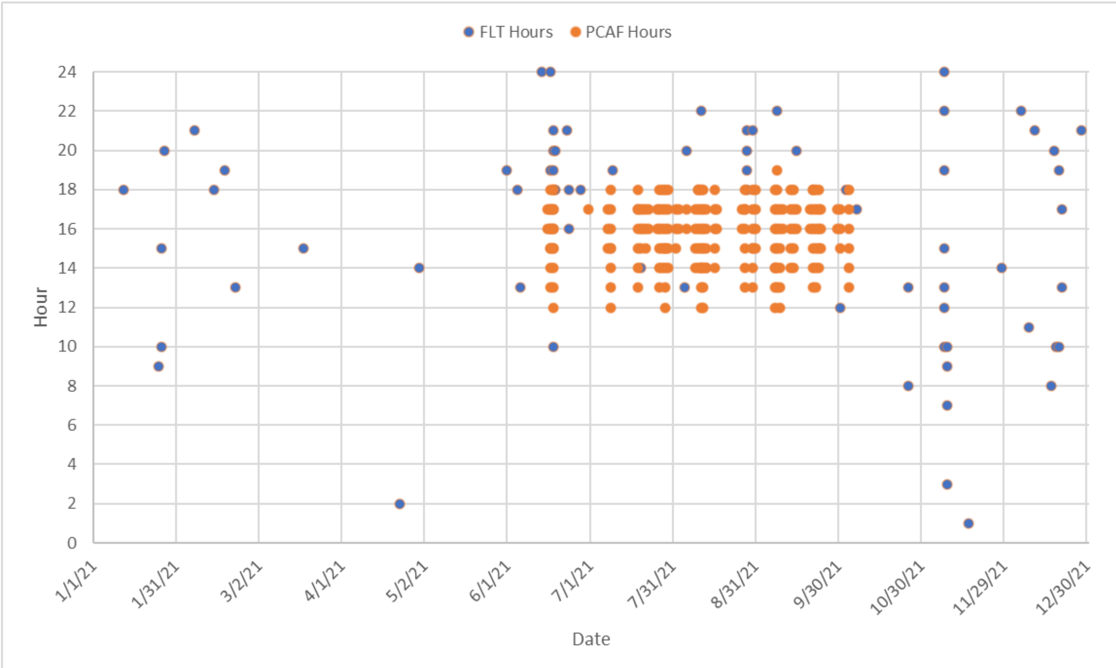
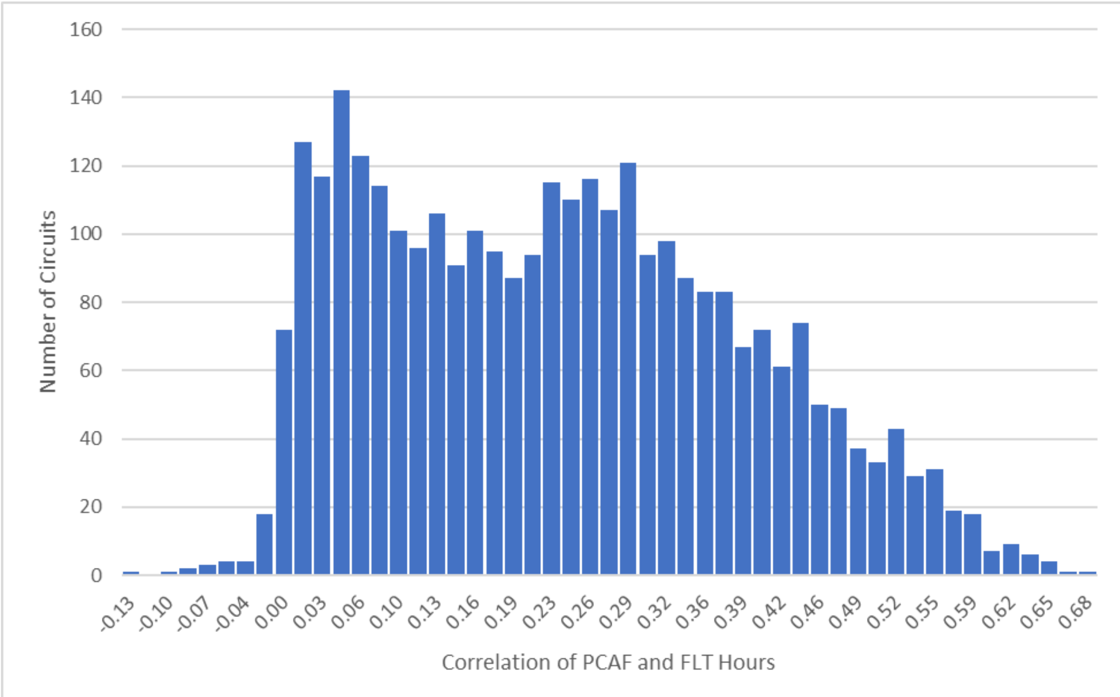


Figure 3 shows how PCAF hours on this circuit are tightly grouped, typically in the afternoon/evening hours during summer months, whereas the FLT peaks on this circuit can occur in any hour of the day, during any part of the year, with very little correlation to the PCAF hours. Using the circuit load to allocate FLT costs would mean sending high price signals on the orange dots when the actual signals should be on the blue dots.

The actual correlation measurement of PCAF vs FLT hours on this circuit sample is 0.12 (very low). PG&E calculated the PCAF to FLT hour correlation for its 3,124 circuits and found that the average correlation is 0.22. A frequency distribution of the circuit-specific correlations is provided in Figure 4 below.

Figure 4: Frequency Distribution of Correlation Between PCAF and FLT Hours by Circuit



To recap, PG&E does not recommend using Option 1 as it would send incorrect price signals and potentially increase system costs overall.

Option 2 acknowledges the marginal cost of load but decouples the price signal from the circuit load. The cost graph for this option would be a straight line increasing to the right. This would be PG&E's preferred option if it were not for the Resolution requirement that the real-time price be bidirectional, i.e., the same price for consumption and exports. Using a fixed adder for Secondary and New Business costs would not be appropriate for exports because exports actually increase utility costs for these components rather than reducing them (i.e., the FLT costs actually look like the second diagram in Figure 2, above). Including these costs in the RTP rate would necessitate a separate export rate, so this option is not permitted under the Resolution.

Option 3 is PG&E's proposal for the VGI pilots and collects Secondary and New Business costs only through the subscription. This method has the advantage that these costs, which are normally collected through cost-based demand charges, can still give the appropriate cost reduction to high load factor customers through a lower subscription amount while not having any demand charges that will vary if a customer shifts their load.

Primary and Transmission Voltage Level Customers

Customers that take service at the Primary voltage level do not incur Secondary and New Business marginal costs, but they have the same Primary costs as Secondary customers. Therefore, the RTP prices for Primary customers will be the same as Secondary customers with the reduced costs reflected in the subscription charge. Transmission voltage customers don't have any marginal distribution capacity costs, which would lead to a distribution value of zero in all hours. All of a Transmission customer's distribution revenue would be collected though the subscription charge.

Clustering of Circuits for Location Based Pricing

PG&E has more than 3,000 circuits in its service territory and developing hourly forecasts each day for every circuit would be a major computational and operational effort. Therefore, PG&E has started a clustering analysis in an attempt to group circuits with similar load profiles together so that a smaller number of RTP prices can be developed.

PG&E's clustering analysis groups circuits into 60 clusters, with an average of 20-50 circuits per cluster. The raw hourly usage data for each circuit includes 24 hours for each of 365 days in a calendar year for a total of 8,760 hours. PG&E looked at the historical RTP prices that would have been developed for each circuit individually and then grouped together the circuits that have the most similar prices. As a result, circuits within a cluster share the same overall load characteristics, such as the timing of high-load versus low-load hours, ramp periods, etc., even if the underlying load magnitudes or geographic locations are different (i.e. a 5 MW circuit and 20 MW circuit can have the same load shape and therefore be in the same cluster.) Clustering circuits in this manner means that a single RTP rate can be utilized for all the circuits within a cluster, vastly reducing the number of circuit-level load forecasts to be modeled.

Developing RTP Rates with Clustering

RTP hourly rate coefficients will be developed for each cluster. To do so, a single representative circuit (the circuit closest to the centroid of the cluster) will be selected from each cluster and used to calibrate the scarcity price curves. PG&E will forecast the loads for these representative circuits to be input into the scarcity price curves to develop a day ahead hourly RTP for each representative circuit. Lastly, the RTP for each representative circuit will apply to all customers/circuits in the representative circuit's respective cluster.

While using the quadratic scarcity method to develop the rates in the VCE pilot, it was initially observed that the rates varied highly between circuits. This had to do with a fundamental assumption in the CalFUSE method of scaling, which the following example clarifies:

> *Suppose that you have two circuits (Circuit A and Circuit B) that are identical and they both have a maximum capacity of 10 MW. The CalFUSE assumption is that they both should collect the same amount of revenue for marginal costs, based on a $/kW capacity cost. However, assume that Circuit A is highly utilized while Circuit B has low utilization. Because the revenue collected from both circuits is identical, Circuit B will have much higher RTP rates.*

To rectify this inequity, PG&E proposed to change the scaling method in the VCE pilot so that every circuit collects the same average $/kWh rate, rather than trying to collect the correct capacity cost in each circuit. PG&E proposes to use the same scaling logic in these pilots. Rates will still vary by location at different times of the day, but all circuits will collect the same average revenue and hopefully address many equality concerns.

Circuits with Very Few Customers

Some of the circuits in PG&E's territory serve only a single customer or very few customers. This raises the same issue as occurs with FLT load - it will be extremely difficult to forecast load on a circuit if a majority of that load is going to be reacting to the prices derived from that load. This "feedback forecasting" may only be possible once PG&E has significant experience in dealing with RTP customers and builds more sophisticated models for how customers react to price signals. Therefore, as a temporary measure, PG&E proposes that any customer that is more than 15 percent of the total load on their circuit would not receive the distribution component of the RTP rate at this time. These customers would still receive the generation RTP signal and would still capture a majority of the value of RTP. This situation should occur very rarely and PG&E suspects that very few, or possibly no customers would be impacted by this provision.

Transmission Rates

Transmission rates are under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and cannot be altered for these pilots. Customers will continue to pay the transmission rates on their OAT.

Subscription Component

As described in the CalFUSE whitepaper, a customer has a "subscription amount" of electricity that they purchase under the OAT – typically assumed to be the amount that they used on a similar day in the previous year. The RTP rate is only applied to deviations from this subscription amount; these would be incremental charges for using more electricity than the subscription, or credits if the customer uses less. Since the RTP rate is only a marginal cost rate, all fixed charges are assumed to be collected in the subscription. This makes the accuracy of the subscription forecast very important, because if the subscription is consistently too high or too low, that will result in an over or underpayment of fixed costs. Assembly Bill (AB) 205 also opens the possibility of collecting NBCs through the subscription instead of actual energy consumption, and PG&E is proposing to do that for these pilots.

The subscription also has the potential to create inconsistent year-over-year compensation. In a scenario where a customer shifts load for a high-priced event one year, the following year their subscription will already include that shift, so they must over-perform to receive any more incentive. Conversely, a customer that decides not to use any energy (e.g. a fallow field) will be a free-rider and receive an incentive despite any actual load management. Finally, the "similar day in the previous year" needs to be chosen with care, as heat waves will not neatly line up year over year, and it is unclear whether load in an August heat wave should have the subscription based on the same day last year (which might have been cool), the hottest day in the previous August (which might still have been free of significant heat), perhaps adjusted for Cooling Degree Days, or similar. These potential issues with subscriptions need to be carefully studied in the various RTP pilots for the next few years.

PG&E is still investigating the best way to set the subscription level, whether it be based purely on historical usage from the prior year or modified with other factors like weather conditions or more recent historical usage. PG&E notes that for rate schedules that are "TOU lite", such as residential and small business, there may be inequities for customers depending on their subscription load profile. A TOU lite customer with an overly large subscription in the peak period may see a windfall from being on the RTP rate, whereas a customer that has already shifted usage may see no benefit or may be harmed.

The subscription component needs more extensive investigation in order for the CalFUSE model to be effective, and PG&E hopes that these pilots will assist in that effort.

Potential Issues That Will Need Investigation

PG&E will proceed with developing a distribution RTP rate as described. However, there are still some existing concerns that PG&E will continue to investigate.

The factors driving circuit level forecasts can vary significantly over short periods of time, resulting in forecasts that can quickly become outdated or stale. Circuit configuration routinely changes for events like maintenance and construction, outage management, and environmental events like PSPS. This reduces how many customers are impacted from an outage by isolating, reconfiguring, and restoring power to healthy sections of a circuit, but also makes it impractical to forecast. It would be detrimental to the grid if customers performed to a price signal that was contradictory to the circuit that had been reconfigured "under their feet". PG&E will need to determine the best way to handle forecasts and cluster assignments when these events occur.

In PG&E's previous RTP proceedings, it has raised concerns around the timing of revenue collection between RTP and standard TOU customers and potential over- or under-collections. Those concerns are still present for this pilot. For example, if there is a summer heat wave with high energy prices and high load on the circuits, RTP customers will pay higher rates immediately, as is appropriate. TOU customers will not pay these higher utility costs immediately, but they will pay them the following year when the revenue under-collection from the heat wave flows into balancing accounts through the usual annual process. The potential problem is that in the following year, the increased rates for standard TOU customers will also increase the subscription rate for RTP customers, essentially making them pay for the heat wave a second time. The opposite situation happens if RTP prices are lower than average. In prior RTP proceedings PG&E has agreed to monitor and measure these potential over/under-collections, but does not recommend any mitigation initially. PG&E maintains the same philosophy for these pilot rates.

Shadow Billing

To avoid the need to integrate the pilot rate tariff with PG&E's billing systems, PG&E will use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot rate. Participants will continue to pay their current PG&E bill under the otherwise applicable tariff and will also receive a shadow bill, which they will not pay. The shadow bill will illustrate a customer's potential savings under the dynamic pilot rate. Participants will receive payments from PG&E for their pilot rate savings at the end of the pilot phase. The payment received by bundled customers will be the total of all differences between their shadow bill and current PG&E bill, but in no case would they be charged a fee if the total difference were negative. PG&E will make a final decision about compensating unbundled customers after coordinating operations with any participating CCAs.

PG&E will credit any savings realized by bundled customers in the customers' shadow bills and will credit any distribution related savings for participating CCA customers.

Funding

Estimated Cost for Implementation of VGI Dynamic Rate

Functionality	Cost	Details
Pricing Engine		Calculate hourly Generation prices. Forecast day ahead hourly load forecast for 60 circuits (representing entire PG&E service territory). Calculate hourly Distribution prices. APIs push prices to required endpoints.
3.2 Shadow Billing Platform		Import hourly generation and distribution prices. Exception management processing. Calculate customers' subscription load profile. Calculate subscription costs based on OAT. Calculate difference from actual energy usage vs subscription load profile. Calculate dynamic portion of customer's bill for each hour. Send bill calculations to downstream applications, including Bill Print. Customer support.
Bill Print		Send shadow billing information to customers (paper & electronic based on customer preference). Remit incentives to customers as required.
3.4 Customer Acquisition & Support		Marketing and acquisition efforts to enroll approximately 1000 residential and 200 non-residential customers. Ongoing customer support, including support for the pricing engine, optimizing technology to perform on the rate, the shadow bill, and customer issues.
Total	**$2,100,000**	

The estimate above is based on the implementation by a third party and does not include any additional efforts by PG&E staff to manage having two sets of participants, one that will be on TOU rates and the other on the VGI Dynamic Rate. Additional effort would include data capture and reporting necessary to compare and evaluate the two groups. Finally, including CCA participation (more on this below) will involve additional outreach and educational efforts.

PG&E intends to file a supplementary Tier 3 advice letter to request that necessary funds be transferred from the Exploring V2X Export Value Pilot which was not approved. The budget of that pilot was set at $2.3 million and covering the above costs would use approximately two million from that budget. The budget for the V2X Export Value pilot included $650,000 allocated to a shared "cloud platform" intended to support itself and the residential and commercial focused pilots. As bids have not yet been received for the "cloud platform" development it is uncertain whether sufficient funds will be available from that pilot to cover all required costs. The amount of budget estimated to still be necessary for the cloud platform is $400,000 as mentioned in the final resolution.

Currently, only bundled customers will be able to participate in the VGI dynamic rate as CCA's do not have a dynamic rate. One possibility is that PG&E could compute a dynamic rate for CCA's and facilitate shadow billing for their customers. While this is technically possible it would require interest from CCAs and support from their boards. PG&E would need to either invoice the CCA for funds to pay their customers at the end of the pilot phase or would need to communicate the required amounts to the CCA so that they could make those payments directly to their customers.

PG&E requests authorization to set up a 2-way balancing account to track expenses related to the shadow bill savings during the pilot.

Timing

Given the ongoing delay in deliveries of EVs and EVSEs due to the chip shortage[8], complexities of implementing the VGI Rate for the pilots and the concern about having enough participants given the possibility that only a fraction of the 30% of PG&E customers that are unbundled would opt into this dynamic rate, PG&E believes it would be prudent to implement this VGI dynamic rate in a separate and additional project phase. In this suggested third phase, all VGI pilot participants would have the opportunity to extend their participation in the VGI pilot if they committed to the VGI Dynamic Rate.

In addition to increasing the expected number of participants, this additional time would also increase the likelihood of gaining CCA participation given the additional time it would take to gain board approval. There also exists a possibility that the cost of implementing the VGI rate may be reduced through efforts that occur in other rate proceedings.

Finally, a key benefit of this approach would be that it lowers the risk for phase 2 of the VGI pilots, helping insure they meet their original objectives while encouraging greater participation in the dynamic rate.

Resolution E-5192 required that PG&E determine the earliest start date of Pilot 2, the commercial VGI pilot and communicate that date as part of this advice letter. PG&E has

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[8] See the following articles for specific examples of these delays:
[Ford co-hosting EV summit to address chip shortage (electrek.co)]
[States, Semiconductors, and the EV Transition (backofthebudget.com)]
[Charging infrastructure companies feeling the bite from the global chip shortage (electricautonomy.ca)]
[Chip Shortage Could Slow Electric Vehicle Rollouts - Scientific American]

requested an extension to the start date of the VGI pilots in a letter to the executive director of CPUC, sent 8/23/2022. The extension was requested due to delays in the availability of bidirectional capable EVSE and EVs and the time it has taken to submit and receive approval for supplemental AIs which have modified the scope of the pilots. Under the assumption that this request will be approved, the first phase of the VGI Pilots would launch November 14, 2022. PG&E expects the first phase of pilot 2 would complete eight months later on July 14, 2023. Phase two of pilot 2 would then begin by August 14, 2023.

The submittal would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

Protests

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than September 22, 2022, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

The protest shall also be electronically sent to PG&E via E-mail at the address shown below on the same date it is electronically delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name and e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 2 advice submittal become effective on regular notice, October 2, 2022, which is 30 calendar days after the date of submittal.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (U 39 E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Stuart Rubio
Phone #: (415) 973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: SHR8@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6694-E Tier Designation: 2

Subject of AL: Rate Structures for Vehicle Grid Integration Pilots

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Resolution E-5192

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 10/2/22 No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Sidney Bob Dietz II, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility/Entity Name: Pacific Gas and Electric Company

Telephone (xxx) xxx-xxxx: (415)973-2093
Facsimile (xxx) xxx-xxxx:
Email: PGETariffs@pge.com

Contact Name:
Title:
Utility/Entity Name:

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
International Power Technology

Intertie

Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.

Resource Innovations

SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy