**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments.	Rulemaking 15-12-012 (Filed December 17, 2015)

**PACIFIC GAS AND ELECTRIC COMPANY
NOTICE OF EX PARTE COMMUNICATION**

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure, Pacific Gas & Electric (PG&E) hereby gives notice of the following *ex parte* communication. The communication occurred electronically on Saturday, June 18, 2016 at approximately 12:00 p.m.

Dennis Keane, Chief Rate Analyst, PG&E, is presenting a paper at the 29th Annual Western Conference sponsored by the Center for Research in Regulated Industries (CRRI), Rutgers University. The conference is being held at the Hyatt Regency in Monterey, California. The paper is titled "Problems with Current Electric Rate Designs: Making Rates Supportable and Sustainable" and is attached to this notice. It will be presented during a concurrent session on Retail Pricing on June 23, 2016 for which Scott Murtishaw, Energy Advisor to Commission President Michael Picker, is a discussant. Mr. Keane uploaded a copy of the paper onto to CRRI website on June 18, 2016 so that Mr. Murtishaw will have access to the paper in advance of the concurrent session.

Respectfully submitted,

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Problems With Current Electric Rate Designs: Making Rates Supportable and Sustainable

by

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Rutgers University
Advanced Workshop on Regulatory Economics
Monterey, CA
June 23, 2016

The views and opinions expressed in this paper are solely those of the author and do not necessarily represent the official positions of PG&E on various rate issues.

1. Introduction

Although electricity generation and delivery is a fixed cost-intensive industry, PG&E currently collects the vast majority of its costs through volumetric rates -- especially for its residential and smaller non-residential customer classes. This results in over-charging some customers for energy, and results in associated large intra-class subsidies from larger customers to smaller ones, as well as from high load factor customers to customers with low load factors. In addition, PG&E's electric rates are further distorted by a variety of other rate structures and subsidies that have been implemented over the years, generally for well-intentioned policy reasons, but which penalize higher usage customers. While economically inefficient and inequitable to those unfortunate customers forced to subsidize others, such policy-driven pricing schemes historically could be supported and sustained because customers were largely captive. However, with the recent rise of new technologies, most notably distributed generation, customers now have alternatives available to bypass (at least partially) utility service. This, coupled with increased sophistication of customers in managing their energy choices, has led to declining sales growth and put upward pressure on rates, resulting in increasingly less accurate and sustainable rate structures.

Building from a discussion of PG&E's electric service cost drivers, this paper describes the inequities in how costs are currently being shared by different customer segments, and the historical reasons for how we got here. It goes on to describe how rate structures are becoming increasingly distorted and less sustainable, and the resulting upward pressure put on rate levels. In particular, the paper describes the challenges faced in reducing volumetric rates from their current, artificially high levels, including overcoming inertia and opposition by various stakeholders who may resist changes to the status quo for either financial or policy reasons. Finally, it presents a number of ideas for how rate structures might be modified to reduce these inequities and subsidies, and send more accurate price signals to encourage appropriate customer investments in new technologies while achieving public policy goals.

2. Marginal Cost Ratemaking

For many decades in California, the California Public Utilities Commission (CPUC) has favored the use of a marginal cost based approach for both electric and gas utility revenue allocation and rate design purposes. Typically, the CPUC looks at three drivers of marginal costs:

- Marginal customer costs – the incremental cost incurred when an additional customer is added to PG&E's system (in units of dollars per customer-month);
- Marginal capacity costs – the incremental cost incurred when an additional kilo-watt (kW) of demand is put on the system (in units of dollars per kW-year); and
- Marginal energy costs – the incremental cost incurred when an additional kilowatt-hour of energy is consumed (in units of dollars per kWh, usually differentiated by time-of-use (TOU) period).

But if rates were set only to cover PG&E's marginal customer, capacity, and energy costs, they would fall well short of collecting the authorized revenue requirement. In the case of electricity generation, rates set at marginal cost levels would only recover about 45 percent of the electric revenue requirement. Similarly, distribution rates set at marginal cost levels would recover just 61 percent of PG&E's electric distribution revenue requirement. These shortfalls indicate the presence of other costs that are essentially fixed, and so not accounted for in marginal costing. These costs include labor, office buildings, poles, taxes, etc. – costs which are very real, but typically do not vary with an incremental customer, an incremental kW, or an incremental kWh.

To collect the shortfall (i.e., the difference between authorized revenue and revenue based on marginal costs), some combination of fixed charges, demand charges, and energy charges must be increased. But despite the fact that the shortfall represents costs that are largely fixed (i.e., that do not vary with usage), the shortfalls are generally collected overwhelmingly from volumetric (dollar-per-kWh) energy charges that do vary with usage. Table 1 illustrates for PG&E. Overall for the PG&E system, more than 80 percent of PG&E's revenues are collected from volumetric charges, and this percentage increases as customers get smaller. Over 95 percent of small commercial customers' bills consist of energy charges, and 100 percent of residential customers' bills are collected with energy charges.

Table 1
Percentage of PG&E's 2016 Revenues Collected
By Various Types of Rates

Customer Class	Customer	Demand	Volumetric	Total
Residential	0.0%	0.0%	100.0%	100.0%
Small Commercial	4.6%	0.0%	95.4%	100.0%
Medium Commercial	5.7%	24.7%	69.6%	100.0%
Industrial	2.0%	41.6%	56.4%	100.0%
Agricultural	2.2%	30.2%	67.6%	100.0%
System	2.0%	16.6%	81.4%	100.0%

Of course, collecting revenues with rate designs heavily weighted towards volumetric rates (or, in the case of PG&E's residential electric customers, exclusively volumetric) results in artificially high energy charges for small commercial and residential customers. For example, while generation costs (the only ones that vary with kWh usage) average a little less than 10 cents per kWh, PG&E's small commercial customers on Schedule A-1 pay from 19.4 to 25.8 cents per kWh, depending on the season and TOU period. The range is even wider for residential customers on PG&E's standard rate, Schedule E-1. E-1 customers pay tiered rates that range from 18.2 to 40.0 cents per kWh. But even for larger customers, more cost-based rates would collect a smaller proportion of revenues through volumetric charges.

3. Rate Distortions When Rates Are Not Cost-Based

The previous section has described how, to varying extents depending upon the customer class, electricity costs that are largely fixed are collected in volumetric energy charges – generally leading to within-class subsidies from higher to lower users. This is particularly acute in the residential class, where PG&E's rate schedules have no monthly fixed charge at all. In addition to rate designs with either small or non-existent fixed charges, a number of other non-cost-based rate designs have been implemented over the years that exacerbate these rate inaccuracies, and result in additional subsidies. These are described in the remainder of this section.

a. Inclining Block Tiered Rates

PG&E is mandated to have a form of inclining block tiered rates as the primary, or standard, rate design for residential customers.[1] The kWh usage boundaries for the tiers are defined in a rather complicated way, based upon the concept of the customer's monthly kWh "baseline quantity." Each residential household is assigned a baseline quantity, depending upon (a) the climate zone in which it is located; (b) whether or not it uses electricity for its space and water heating; and (c) whether the billing month is classified as "summer" or "winter."[2] Specifically, the tier boundaries are defined as follows:

- Tier 1 – usage between zero and 100 percent of baseline quantity;
- Tier 2 – usage between 100 and 200 percent of baseline quantity; and
- Tier 3 – usage over 200 percent of baseline quantity.

Table 2 illustrates, using PG&E's current residential rates. The table shows that Tier 1 usage (i.e., usage up to the customer's baseline quantity) is priced at 18.2 cents per kWh. Once usage crosses into Tier 2, though, it is charged a price about 6 cents higher, 24.1 cents per kWh, for each Tier 2 kWh. Once usage crosses into Tier 3, the price further increases by a whopping 16 cents, to 40.0 cents per kWh.

Table 2
Residential Schedule E-1 Rates by Tier
Effective June 1, 2016

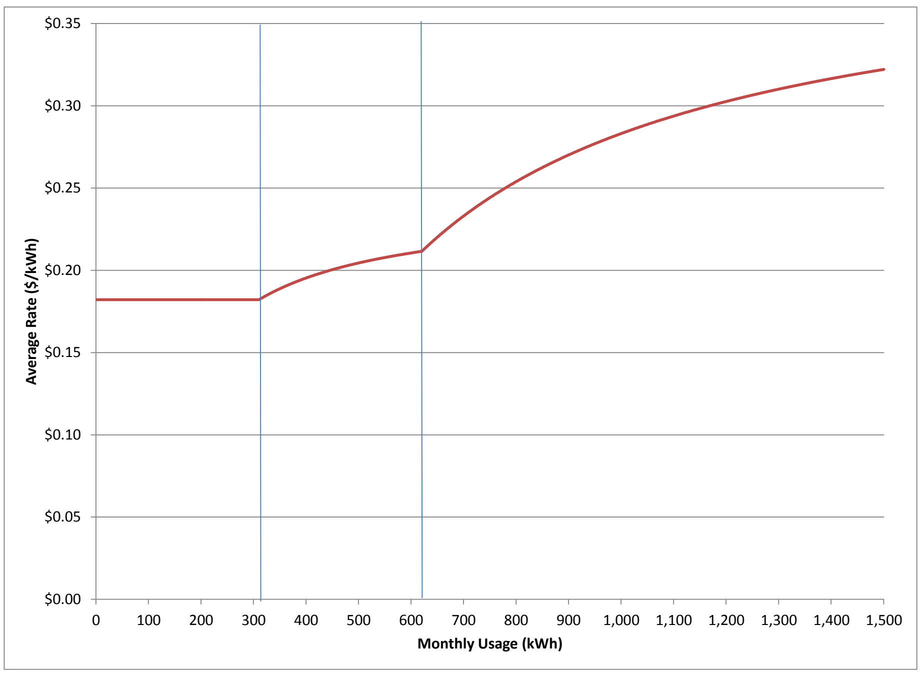
Tier	Usage Range	Rate ($/kWh)
Tier 1	0 to 100% of Baseline Quantity	$0.18212
Tier 2	100% to 200% of Baseline Quantity	$0.24090
Tier 3	Over 200% of Baseline Quantity	$0.39999

Figure 1 shows how a customer's average rate paid (i.e., the bill divided by the customer's usage) changes with its monthly usage amount under tiered rates. The

[1] This requirement, enacted by the California legislature, also applies to the other two California investor-owned utilities (IOUs), Southern California Edison and San Diego Gas and Electric.
[2] The tiered rates themselves do not vary with any of these three factors, but the baseline quantities (and thus the tier boundaries) do. So while the tiered rates facing a customer in Bakersfield, say, are identical in both summer and winter, the tier boundaries will differ (allowing for many more kWh to be consumed in summer before moving to a higher tier).

vertical blue lines show the tier boundaries.[3] For usage within Tier 1, the average rate is simply equal to the Tier 1 rate of 18.2 cents. As soon as usage enters Tier 2, though, the average rate begins to increase, since it is now a weighted average of the Tier 1 and 2 rates (with the weights being the shares of sales in Tier 1 and 2, respectively). Once usage enters Tier 3, the average rate begins to increase at an even greater rate.[4]

Figure 1
Residential Tiered Rates: Average Rate vs. Usage
For Territory X Customer (Summer, Basic Service)



So, while costs do not increase with cumulative monthly usage, inclining block tiered rates require upper-tier users to pay average rates well in excess of those charged to lower-tier users – and the greater the usage, the higher the average rate. Steeply-tiered rates are economically inefficient and not cost-based. Not only do they result in large subsidies from upper-tier to lower-tier users, but they also deprive customers of the value they could be getting from using electricity. Consider, for example, a customer who is considering leaving her porch light on overnight for reasons of home security. The cost

[3] For ease of exposition, this graph ignores the $10 residential minimum delivery bill that also applies to customers taking service on Schedule E-1, in order to focus exclusively on how the inclining block rates affect the average rate paid by the customer as its usage increases.
[4] The graph shows monthly usage only up to 1,500 kWh. In the limit, as usage gets larger and larger, the average rate curve approaches 40.0 cents (the Tier 3 rate) asymptotically.

to PG&E of supplying electricity in the middle of the night is quite small – less than 10 cents per kWh. But suppose the customer finds herself several days from the end of the billing cycle and already consuming in the top tier. She might be perfectly willing to spend well above the 10-cent cost of the electricity for the peace of mind of enhanced security. She might be willing to pay, say, 20 cents, or even 30 cents. But, because of the steeply tiered rates, the price of those upper-tier kilowatt-hours is an astounding 40 cents -- which exceeds her willingness to pay. This is economic inefficiency at its worst: a customer who could have been able to derive utility from consuming a valuable and inexpensive product but, instead, is priced out of doing so by a perverse rate structure that penalizes upper-tier users.

It should be noted that, per the CPUC's July 2015 decision in the Residential Rate Order Instituting Rulemaking (RROIR Decision),[5] the CPUC has begun a multi-year reform of the tiered rate structure, reducing the number of tiers in June 2016 from four to three, with the previous Tiers 2 and 3 being combined. In early 2017, the current Tiers 2 and 3 will be combined, which ostensibly reduces the number of tiers to two. However, the RROIR Decision at the same time also mandated the creation of a new super-user electric (SUE) surcharge tier that will apply to usage in excess of 400 percent of baseline -- so in actuality there will still be three tiers, with the customers in the highest tier continuing to pay inaccurate, inefficient rates. The RROIR Decision's glide-path for tier rate ratios specifies that, by 2019, PG&E's SUE tier rate is to be set at more than double (2.19 times) the Tier 1 rate. Thus, for those customers in the highest tier, there is no end in sight to being charged inefficient rates far in excess of their cost of service.

b. Rates Without Fixed Charges

PG&E's fixed costs are incurred to serve all customers. A rate structure with a monthly fixed charge would collect a portion of these fixed costs from all customers on an equal basis. For example, if PG&E were able, like SMUD, to charge a $20 monthly fixed charge,[6] then a customer using 100 kWh would contribute the same amount ($20) to recover fixed costs as one who used 1,000 kWh. This is an equitable and cost-based

[5] CPUC Decision 15-07-001.
[6] In May 2013, SMUD's board approved residential rates with a system infrastructure charge of $20, along with a plan to phase it in from the then-current level of $12 to $20 over a four-year period. So SMUD's current charge is $18, and will be $20 beginning January 2017.

outcome, since fixed costs are incurred to serve both customers.[7] But in the absence of a monthly fixed charge, these fixed costs instead are rolled into volumetric rates and, consequently, resulting in the 1,000 kWh customer paying ten times the amount as a 100 kWh customer.

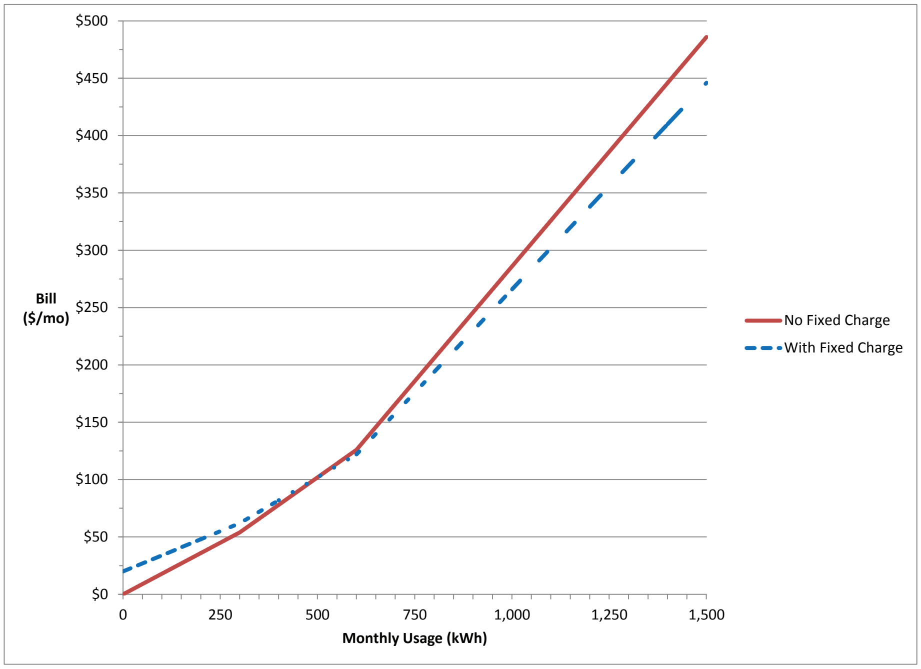
Figure 1 illustrates the situation for customers with a baseline quantity of 300 kWh per month.[8] The locus of points in red shows customer bills at various usage amounts. This locus is made up of three linear segments, with varying slopes equal to the Tier 1, 2, and 3 rates. These slopes increase as usage moves above 300 kWh (the boundary between Tiers 1 and 2), and again as usage moves above 600 kWh (the boundary between Tiers 2 and 3). The locus of points in blue shows customer bills as a function of monthly usage if a $20 fixed monthly charge were in effect. With the fixed charge, there is now a $20 y-intercept, indicating that even a customer with zero usage in a month would now be obligated to contribute $20 towards fixed costs. But the additional revenue collected by this charge would enable lower volumetric rates to be charged. In this example, the additional fixed charge revenue reduces the volumetric rates in each tier by 4 cents per kWh,[9] so the slopes of each of the blue line segments are lower than their respective red line segments by 4 cents per kWh. Beyond a cross-over usage amount of about 500 kWh, customers will be better off (i.e., have lower bills) under a rate structure that includes a fixed charge. Higher usage customers would benefit from a move to a fixed charge rate structure, as they would no longer be shouldering a disproportionate amount of the fixed cost burden, while lower usage customers would

[7] Some portions of fixed costs, like interconnection facilities and meters, might vary between groups of residential customers of different sizes.
[8] A round figure of 300 kWh per month is used in this example, but this is very close to the 310 kWh per month summer baseline quantity in PG&E's most populous climate zone, Territory X. For ease of exposition, this graph ignores the $10 residential minimum delivery bill that also applies to customers taking service on Schedule E-1, in order to focus exclusively on how the presence or absence of a customer charge affects customer bills under an inclining block tiered rate structure. Minimum bills are discussed later in the paper in Section 5.c.
[9] While this simple example assumes an equal cent reduction in the volumetric rate in every tier, the RROIR Decision actually would not allow this. Rather, that decision specifies that the ratios between upper-tier rates and the Tier 1 rate be calculated based on a concept called the "composite Tier 1 rate," which is defined as the sum of fixed charge and Tier 1 revenue, divided by Tier 1 sales. Because of this, the implementation of the fixed charge would only lower the Tier 1 rate. In this example, instead of a 4 cent reduction in every tier's rate, the Tier 1 rate would decrease by 8 cents, with no changes to the Tier 2 or 3 rates. This aspect of the decision, if not modified in future decisions, will greatly restrict the ability of a fixed charge to provide upper-tier consuming households with bill relief and decreased bill volatility.

have higher bills, as they now begin to bear a larger and more equitable share of fixed cost responsibility.[10]

Figure 2

Residential Bill vs. Usage: With and Without a Fixed Monthly Charge



c. Discounted Rates for Low-Income Households

PG&E, like most utilities in California and elsewhere, offers discounted residential rates or other financial assistance to qualifying low-income households. PG&E's low-income rates, known as the California Alternate Rates for Energy (CARE) program, are not cost-based, because they reflect a desire by policymakers to provide assistance to families who have difficulty paying their electric bills.[11] However, unlike most other utilities, PG&E's CARE discounts have soared over the past two decades or so. In 1993, CARE rates for Tier 1 and Tier 2 were 10.1 and 11.7 cents, respectively, and represented a 15 percent discount compared to non-CARE rates. For the next 22 years, from 1993 until 2015, due to a combination of regulatory policy and legislative

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[10] This example illustrates the benefit of implementing a fixed charge in terms of reducing the current subsidy from large to small users, in a situation where a fixed charge did not previously exist. Similar examples could be constructed for non-residential customer classes where, although a fixed charge exists, it does not fully collect fixed costs. In those examples, the y-intercept value would increase while the slope of the line would decrease, which would likewise provide relief to higher users who currently are bearing a disproportionate share of the fixed cost burden.

[11] PG&E's CARE customers also receive a discount on their gas rates, although the percentage discounts for gas are substantially smaller than those provided for electricity.

restrictions on rates that grew out of the energy crisis of 2000-2001, PG&E's CARE rates never increased above those levels.[12] Instead, when residential rates increased over those two decades plus, as a result of inflation and other factors, CARE customers were completely insulated from any rate increases. And since non-CARE rates kept increasing, the CARE discount rose steadily, peaking at 53.5 percent for the average CARE customer in 2010.[13] Since about 30 percent of PG&E's customers took service on CARE rates at the time, this represented over $870 million of annual CARE discounts that had to be paid, instead, by other customers.[14]

In early 2010, PG&E filed a Summer 2010 Rate Relief application at the CPUC focused on reducing extremely high upper-tier non-CARE rates. Several months later, the CPUC approved a settlement between PG&E and consumer groups to reduce the top-tier non-CARE rate (which had reached 49.8 cents), and this finally began to reverse the rising trend of CARE discounts. Since then, in a number of subsequent Commission proceedings, the Commission, utilities and stakeholders have made further progress in reducing the CARE discount percentage to more balanced levels that maintain a significant assistance level while reducing the burden of the subsidy on non-CARE customers. In particular, the CPUC's decision in PG&E's 2011 GRC Phase 2 proceeding implemented a new third tier for CARE customers with higher rates, and the California Legislature and the CPUC's Residential Rate Order Instituting Rulemaking (RROIR) have approved subsequent increases to CARE rates to reduce the subsidy – all of which have aided in bringing the CARE discount percentage down from its 54.5 percent high water mark.[15]

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[12] In late 2011, the CPUC did authorize PG&E to add a third tier to its CARE rates, so higher-usage CARE customers only had an 18-year period of no rate increases.

[13] Post-energy crisis, the CARE discounts have no longer been set as constant percentages off the non-CARE rates. Rather, they have been left to float as non-CARE rates increased while CARE rates did not. Moreover, after the energy crisis, for much of the post-energy crisis period, non-CARE rates had five tiers and rate Tier 1 and 2 usage was also protected from rate increases – resulting in soaring Tier 3, 4 and 5 rates. Consequently, the CARE discount percentages became much higher in Tiers 3, 4 and 5 than in Tiers 1 and 2. But, for CARE customers overall, the average discount reached 53.5 percent in the spring of 2010.

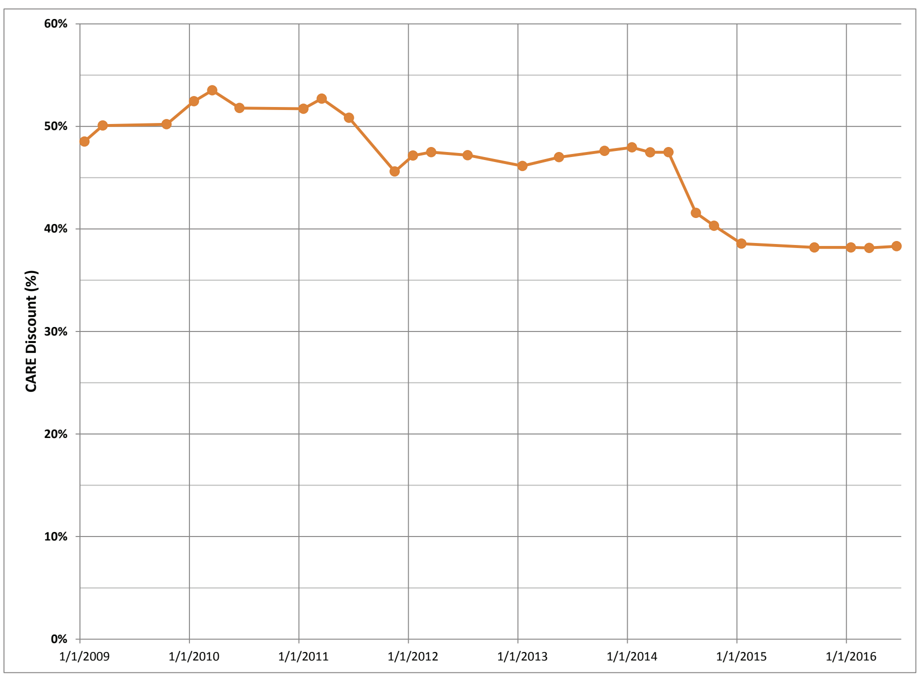
[14] The costs of the CARE discounts are spread to non-residential customers, as well as non-CARE residential customers.

[15] The CPUC also approved another PG&E proposal to require very high usage CARE customers to either agree to an energy efficiency audit or be removed from the CARE program. Many of these very high usage customers (who were receiving the largest percentage discounts) declined the audit and were placed on non-CARE rates, which also helped reduce the overall CARE discount percentage.

Figure 3 shows the trend in PG&E's CARE discount percentage since 2009, shortly before it peaked. Since its peak in the spring of 2010, the annual CARE discount in dollar terms has declined from the aforementioned $870 million to about $600 million today. This is still a large figure, though, and adds 0.7 cents per kWh to the volumetric rates of other customers. In 2013, the California legislature enacted Assembly Bill (AB) 327, which directed the CPUC to ensure that, after a reasonable transition period, rates be set such that the CARE discount lies in the range between 30 and 35 percent. So, while these percentages are a substantial reduction from the 2009-2011 years when the CARE discount exceeded 50 percent, absent new legislation the "new normal" for the CARE discount percentage still will exceed 30 percent -- well above its 15 percent level in 1993 and also 1.5 times its 20 percent pre-energy crisis level.[16]

Figure 3

PG&E CARE Discount Percentage Since 2009



[16] In comparison, other publicly-owned utilities in Northern California show the following discounts: Modesto Irrigation District – 23 percent (limited to Tier 1 usage only); Turlock Irrigation District – 15 percent (limited to Tier 1 usage only); Alameda – 25 percent; Silicon Valley Power (Santa Clara) – 25 percent (limited to the first 800 kWh of usage only); and Healdsburg – 20 percent (limited to Tier 1 and 2 usage only). SMUD is an outlier, with a 44 percent discount, but SMUD caps the total dollar discount a customer can receive in a month to $43. In Southern California, Los Angeles Department of Water and Power offers a 20 percent discount.

d. Rates Without Demand Charges

In order to provide electric service, PG&E must build or procure capacity sufficient to generate and deliver kilowatts as they are demanded in real time. But if PG&E's generation, transmission and distribution capacity costs are collected only through energy charges, then customers do not see a price signal that tells them what their loads cost, and have no incentive to manage their appliance or equipment loads so as to not all be operating simultaneously. This results in more capacity being needed than would otherwise have been the case if customers had been on rate structures with demand charges -- and thus to higher overall rates.

In addition to managing capacity costs, demand charges are more equitable for customers, as they mitigate the subsidies that otherwise exist from high load factor customers to those with low load factors. This is illustrated in Figure 4, which shows the hourly load shapes of two illustrative commercial customers. Customer A has a load of 400 kW, but it is intermittent, only on for an hour three separate times during the day. Customer B, on the other hand, has a completely flat load of 50 kW for all 24 hours of the day. Both use the same amount of daily energy, 1,200 kWh, but Customer B has a 100 percent load factor while Customer A's load factor is much lower, 12.5 percent.[17] Since they each use 1,200 kWh on a daily basis, in terms of energy costs both cost the same to serve. And if both are served under a rate schedule with no demand charges, then both will have identical bills[18] However, low load factor Customer A clearly costs more to serve, because it requires eight times the amount of capacity be available to serve as Customer B. Under a rate structure with a demand charge (and a commensurately lower energy charge), Customer A would appropriately pay more than customer B.

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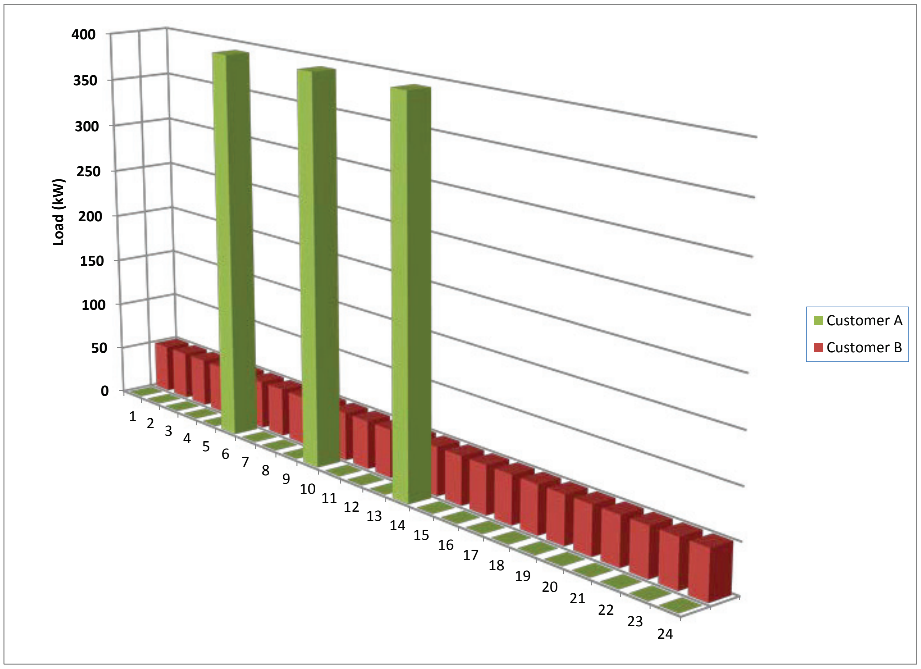
[17] The customer's load factor is its average load over a period of time divided by its maximum load over that same period. For Customer B, both average and maximum loads are 50 kW, so its load factor is one (or 100%). While Customer A also has an average load of 50 kW, its maximum load is 400 kW, so its load factor is .125 (or 112.5 percent).

[18] To keep the example simple, the time-varying nature of energy costs is ignored in this example, and a flat energy charge is assumed rather than one which varies by time-of-use period. A more complex example could be constructed where both customers' loads are spread out over both peak and off-peak hours so that both would have identical usage in each time-of-use period – and thus still have identical energy cost of service.

Figure 4
Illustrative Customer Load Shape Comparison



This example, while a bit extreme to highlight the point about demand charges, has specific relevance to electric vehicle (EV) charging. Depleted EV batteries require a certain amount of kWh energy to become fully re-charged. This energy can be supplied in a variety of ways, ranging from charging equipment with relatively low kW demands operating over a relatively long period of time (e.g., eight hours) to “quick charge” equipment with much higher kW demands operating over a much shorter period of time (e.g., an hour or less). While both ultimately use the same amount of kWh to recharge the EV’s battery, the “quick charge” equipment requires the utility to have more kW distribution capacity available to meet the higher load, and thus imposes a higher cost. Consequently, per-kW demand charges are needed to accurately charge those customers whose EV chargers impose greater loads on the system. Such demand charges send more accurate price signals which reflect the cost of the extra capacity needed to meet those larger loads.

e. Non-Time-Differentiated or Incorrectly Time-Differentiated Rates

There is universal agreement that TOU rates, which distinguish high-cost periods from low-cost ones, better reflect actual costs of service than rates which are non-time-differentiated -- and thus provide more accurate price signals to customers making decisions when to use electricity (and also whether or not to invest in technologies that would help them shift load). When customers respond to TOU price signals by shifting load from high-cost to low-cost periods, the same amount of energy can be produced and delivered at a lower cost – thus keeping rates lower than they would otherwise be. Yet for many years TOU rates were mandatory only for the largest non-residential customers. Smaller business and agricultural customers, along with residential customers, had access to TOU rates, but on a voluntary, opt-in, basis. Residential and smaller non-residential customers typically did not have meters capable of measuring kWh usage or kW demands by TOU period, so a customer who wished to take service on a TOU rate could volunteer to do so, but was assessed a meter charge to cover the incremental cost of its TOU meter.

The situation now is very different, with the widespread installation of Smart Meters that collect usage data at very short time intervals (e.g., at 15-minute intervals). Such interval data can now be acquired each month from almost all PG&E customers, and aggregated into TOU period "buckets" corresponding to particular tariff definitions. Accordingly, since 2012, PG&E's small and medium commercial customers, as well as its agricultural customers, have been moved onto mandatory TOU rates that better reflect cost of service. Despite this progress enabled by Smart Meters, though, there are still two reasons why TOU rates may fall short in terms of sending more cost-based price signals to customers.

i. Customers Not on TOU Rates

The first reason is the existence of statutory restrictions on the CPUC's ability to place residential customers on TOU rates without their consent or their right to opt-out of the rates. The CPUC is prohibited from mandating TOU rates for residential customers, who must be provided with a tiered rate structure should they so desire one. The aforementioned AB 327 allows the CPUC to default residential customers to TOU rates – but only after 2018 and with the right to opt-out, and only after the CPUC has ensured that doing so does not cause unreasonable hardship for senior citizens or economically vulnerable customers in hot climate zones. Subsequent to AB 327, the legislature in 2014 enacted Senate Bill (SB) 1090, which placed additional conditions on the CPUC before it could authorize default TOU rates. These SB 1090 conditions require the CPUC explicitly examine evidence on the extent to which hardship would be caused on particular groups of customers, including those living in hot inland areas and facing seasonal bill volatility. So, pending the results of the CPUC's examination, a significant subset of customers may end up being exempted from default TOU. And even those customers who may permissibly be defaulted will still be provided a choice between TOU and tiered rates prior to any default occurring. Only those customers who do not affirmatively choose to remain on tiered rates will be defaulted to TOU rates. Moreover, even if they fail to opt-out initially, and thus end up being defaulted to TOU rates, they may subsequently opt-out and return to tiered rates if they wish. So it remains to be seen what percentage of residential customers will eventually be served on TOU rates.

ii. Customers on TOU Rates With Incorrect Hours

The second reason why current TOU rates fall short is that, for many customers, the TOU periods are no longer aligned with the time pattern of generation costs. For decades, the highest hourly generation costs tended to match the hours of highest system loads. That was because, as temperatures rose and system loads increased, less and less efficient power plants had to be dispatched to meet those increased loads. The high load hours tended to occur on weekdays from May through October, between the hours of noon and 6:00 p.m. Consequently, all of PG&E's TOU rates charged higher peak period prices during those summer hours (or hours which varied just slightly from the noon to 6:00 p.m. period).

However, over the last several years, this situation has changed dramatically, as a result of (a) large increases in the amounts of renewable power in PG&E's generation/procurement portfolio; and (b) substantial increases in the amounts of customer load being served via on-site, behind-the-meter, solar generation units. Now PG&E's generation costs are no longer driven by its gross system loads, which tend to peak in the mid- to late-afternoon hours, but rather by what PG&E has termed its "adjusted net load" (ANL). ANL is defined by starting with the load that PG&E must serve (which already excludes consumption served by on-site generation) and then netting out (a) must-take renewable solar and wind resources, (b) baseload nuclear, and (c) hydro. ANL is essentially the remaining load that must be met by dispatchable gas-fired generation units. Those gas-fired units, just like in decades past, are dispatched in order of efficiency, so the highest cost hours are those hours with the highest ANLs. Unlike gross loads, though, ANLs peak in the evening hours, generally between 4:00 p.m. and 10:00 p.m. In addition, there are very low ANLs beginning to occur during spring, from mid-morning through mid-afternoon hours, corresponding to very low generation cost hours.[19]

The cost data show that, quite clearly, the peak period for PG&E's TOU rates needs to be redefined, and soon. The movement of the highest cost hours to later in the day has been occurring over the last few years, and is expected to continue based on forecasts for the 2020-2024 period. Thus, TOU rate schedules with noon to 6:00 p.m. are already obsolete, making it critical that the peak period hours be moved to later in the day as soon as possible. In the residential sector, this has already occurred for PG&E, at least on a going-forward basis.[20] In PG&E's 2015 Rate Design Window (RDW) proceeding, PG&E proposed later in the day peak periods for its new Schedule E-TOU, as well as a shorter, four-month, summer season from June through September when concentrations of high generation cost hours occur. In November 2015, the CPUC approved two Schedule E-TOU options, one with peak hours from 4:00 p.m. to 9:00 p.m. and the other with peak hours from 3:00 p.m. to 8:00 p.m.[21] For non-residential customers, PG&E will soon be proposing to similarly move the peak hours to later in the day, in Phase 2 of its 2017 General Rate Case (GRC) due to be filed on June 30, 2016. That proposal will also include a super-off-peak period for some TOU rate schedules, to provide even lower rates during spring hours when generation costs – though not overall costs -- are very low (or even negative).

f. Favorable Rates for Particular Technologies or Situations

The legislature and/or the CPUC have, in several instances, deviated from cost-based rate design and provided favorable rate structures for particular favored technologies, or in certain situations. The first and most prominent example is for customers installing on-site solar units, who, in the interest of furthering the policy objective of encouraging solar, were allowed to take service on net energy metering (NEM) rates which substantially over-compensate them during hours when they are net

[19] PG&E's ANL patterns are not too different from the net load "duck curve" patterns the California Independent System Operator (CAISO) has been publishing in recent years, although PG&E's ANLs (and thus its costs) peak about an hour later than the net load of the statewide duck curve, at least in the summer and fall.

[20] One of PG&E's existing residential TOU rates, Schedule E-6, was grandfathered, and will retain its 1:00 p.m. to 7:00 p.m. peak period hours through 2020.

[21] The option with the 3:00 p.m. to 8:00 p.m. peak period hours is temporary; those hours will transition to 4:00 p.m. to 9:00 p.m. beginning in 2020.

exporters to the grid, relative to the market value of those exports.[22] The future of NEM in California and other states has been much in the news over the last several years, as utilities have attempted to reform NEM and replace it with more cost-based rate structures that better reflect actual market prices for renewable energy, and a detailed discussion is beyond the scope of this paper (it would be a whole other paper, perhaps a whole other book). Suffice it to say, though, that the original NEM program, where customers with on-site solar are compensated at full retail rates, was found by the CPUC's own consultant to result in shifting billions of dollars in costs onto non-solar customers. The Public Tool, developed by the consultant under the direction of CPUC staff, showed that by 2025, if NEM is not changed, the costs incurred by other customers to subsidize solar customers will total $3.6 to $5 billion per year, adding $21 to $24 per month to the bill of an average non-CARE PG&E residential customer, and $13 to $15 per month to the bills of PG&E CARE customers. PG&E's own estimates were substantially higher. Moreover, the new, replacement, NEM program does little to alter the magnitude of the subsidy, as the changes to NEM approved in the Decision had less than a 5% impact on cost shifts. The Commission did not even decide on the size of the subsidy or whether it was needed, and instead deferred addressing these issues until sometime in the future.

A second example is rates for transit agencies deploying electric buses. In an early decision, issued in July 2011, the CPUC recognized that EV charging, especially fast-charging equipment, would place significant additional kW loads onto the grid, and so required all non-residential customers offering EV charging to do so on rates that included demand charges to signal that capacity cost.[23] However, later, a temporary exception for transit agencies was made, allowing them to take service on the small commercial rate (Schedule A-1, without a demand charge) rather than the medium

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[22] Solar-installing customers received a number of other incentives, as well, including direct rebates from the Self-Generation Incentive Program and exemptions from paying non-bypassable charges and standby rates that customers with other distributed generation technologies were obligated to pay.

[23] So if a small commercial customer on PG&E's Schedule A-1, which does not include a demand charge, wished to install EV charging facilities, it would be required to switch to a rate like Schedule A-10 which does have a demand charge. This is an appropriate way to ensure that EV chargers pay for the additional capacity needs required to provide that service.

commercial rate (Schedule A-10, with one), when the load of their fast-charging equipment would otherwise have been too large to qualify for Schedule A-1.[24]

Fast-charging equipment for an electric bus can add large loads (several hundred kilowatts) for relatively brief periods of time (10 to 20 minutes), and then the bus drives away and does not require re-charging for several hours. This means significant capacity is required to serve the charging load, capacity that will be idle for the vast majority of the hours of the day. These capacity costs exist whether they are built to serve a favored end-use like electric vehicle charging or some other load like, say, refrigeration for a warehouse (where, for a similar-sized load, the business would have to pay a demand charge). If customers do not face a demand charge that appropriately signals to them the capacity cost of their service, they will have no incentive to choose a slower charging method that places a smaller kW demand on the system, or to stagger bus schedules to avoid charging multiple buses at the same time. In addition, not having to face a demand charge provides no incentive for them to explore energy storage options. Energy storage might enable the transit agency to reduce the load they put on the grid while at the same time increasing their utilization of the grid during periods while the buses are on their routes and not charging, thus improving their load factors and reducing periods of excess grid capacity.

4. Are Rate Structures With Artificially High Volumetric Rates Supportable and Sustainable?

For all of the reasons described in the previous section, PG&E's rates contain energy charges far higher than its actual variable costs of providing service. This results in inaccurate price signals, economic inefficiency, and hundreds of millions of dollars in subsidies (from upper-tier to lower-tier users, from high load factor to low load factor customers, from non-CARE and non-residential customers to CARE customers, from non-NEM customers to NEM customers, etc.). Still, if the customers providing the subsidy to others have no alternative to PG&E service, or are unsophisticated, these non-cost-based rate structures can be supportable and sustainable. Not fair in the sense of being cost-based, but supportable and sustainable. And state decision-makers (the legislature and the CPUC) may deem the achievement of certain public policy objectives

[24] The exception lasts for three years, beginning September 30, 2013.

worth the price of having artificially high energy rates and large subsidies. But, increasingly now, customers are more sophisticated about hidden subsidies and have more alternatives. They are no longer ignorant or captive customers who can be "milked" to support and achieve these policy objectives without their affirmative "buy-in."

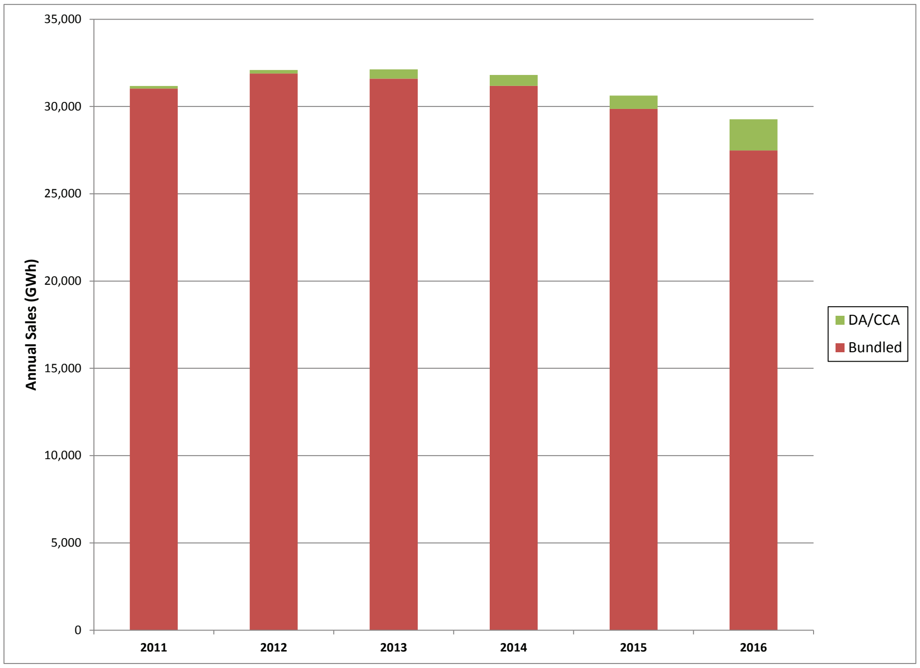
Rooftop solar is now an option for many, and installations have been growing rapidly in recent years. Moreover, the upper-tier consuming households – those paying the highest rates – are the primary target for solar vendors looking to exploit niches caused by distorted rates. The higher the average rate they are paying, the more economically attractive the solar unit will be. They will not continue to tolerate being price-gouged when alternatives are available.

Figure 5 shows the recent trends in PG&E residential electricity sales, for the 2011-2016 period, based on CPUC-approved sales forecasts in PG&E's annual Energy Resource Recovery Account (ERRA) proceedings. The red bars show PG&E's bundled sales, while the red plus the green bars show PG&E's total delivery sales, which include sales made to customers who receive generation service from a direct access provider or a community choice aggregator (CCA).[25] Since 2012, annual bundled residential sales have decreased by about 4,400 GWh (from 31,900 to 27,500 GWh), a decline of 3.7 percent per year. The main drivers of this loss in sales are customers installing rooftop solar units, energy efficiency (in particular, the mandated transition away from incandescent light bulbs to more efficient bulbs), and the increased availability of CCA in many cities. The effects of the last driver, migrations to CCA service, are shown by the increasing size of the green bars in the chart. Since 2012, sales to customers of CCAs have increased by 1,600 GWh (from 200 to 1,800 GWh), a growth rate of 73 percent per year. Since CCA customers remain PG&E customers for delivery service, these lost sales only reduce generation revenues. Still, focusing on the sum of red and green bars

[25] CCA service is similar to direct access, where a non-utility entity procures power for customers but the utility continues to provide delivery service. The main differences are that CCAs must be public agencies and that CCAs do not have to solicit customers to opt in to their service (they are the default generation providers for customers in their service areas).

show that total sales delivered through PG&E's system have also declined since 2012 by 2,800 GWh (from 32,100 to 29,300 GWh), or 2.3 percent per year.[26]

Figure 5
Recent Trends in PG&E Residential Sales: Bundled and DA/CCA



As more and more customers become knowledgeable about the hidden subsidies and inaccurate prices in their utility bills, they will become less trustful of their electricity providers as well as policymakers. As more and more of those customers partially bypass PG&E's system by meeting a portion of their monthly usage with on-site solar units, PG&E's sales will decline. Customers may still be consuming as much as they ever did but, with some of that consumption served by their on-site generation, they will be consuming less electricity that is generated or procured by PG&E and delivered through PG&E's wires. With the decline in PG&E sales comes a decline in revenue. However, PG&E's costs do not decline in equal measure. While PG&E avoids having to produce or procure the generation that has been displaced by the on-site solar, the other costs of service – fixed costs, transmission, distribution, public power and other non-bypassable charges – largely remain unchanged. The resulting shortfall (due to the lost revenues exceeding the avoided costs) then has to be collected from PG&E's remaining

[26] A similar, though less pronounced, trend has been seen since 2012 for total PG&E system sales, where bundled sales have declined by 1.9 percent per year, CCA sales have increased by 9.4 percent per year, and total sales have decreased by 0.5 percent per year.

customers via rate increases. Much of this bypass may be uneconomic, meaning it would not have occurred had rates been in effect that appropriately reflected the costs of service. But with artificially high energy charges, a vicious cycle is created once customers have alternatives: lost sales beget lost revenue, which begets rate increases, which begets additional lost sales, and so on. Compounding the problem is the fact that, in the residential sector, the lost sales occur predominantly in the top tiers. This results in a disproportionately large amount of lost revenue and a disproportionately large rate increase to collect the shortfall (which often gets allocated primarily to the upper tiers, to continue the cycle).[27]

An historical example of how support for distorted rates cannot be sustained once formerly captive customers have alternatives is PG&E's experience in 2010 when Marin Clean Energy (MCE) became the first CCA to begin operating in California. A CCA customer receives a credit on the generation portion of its PG&E bill, and instead pays the CCA for generation. So, for a CCA to be economically attractive to a customer, its generation rate must be lower than PG&E's generation rate.[28] If it can provide generation for less than PG&E's generation rate (plus the PCIA), then the customer will save on its entire electric bill.

As described above in Section 3.a, PG&E's standard residential rates must be tiered, with higher rates charged for usage in higher tiers. In May 2010, when MCE first began providing CCA service to residential customers in Marin, not only did the total bundled rates increase as the customer's usage moved into higher tiers, but so did the generation component of rates. Specifically, while PG&E's average generation rate was 8.2 cents per kWh in May 2010, the actual generation rates charged steeply tiered customers were as follows:

- Tier 1 – 4.3 cents;
- Tier 2 – 5.2 cents;

[27] Between 2015 and 2016, PG&E's non-CARE sales decreased 5.5 percent. Tier 1 sales, though, actually increased by 2.8 percent, while Tier 2, 3 and 4 sales decreased by 9.7, 16.7 and 18.4 percent, respectively.

[28] To ensure the PG&E's remaining bundled customers are not harmed by a customer choosing CCA service, the CCA customer also must pay a non-bypassable charge to PG&E called the power cost indifference amount, or PCIA, to cover PG&E's above-market generation costs incurred on the CCA customer's behalf prior to its departure. So CCA service will cost less than PG&E bundled service if the CCA can beat PG&E's generation rate by more than the amount of the PCIA charge. For some customers, too, the renewables content of the CCA's power is an important factor in its decision. So a CCA which is "greener," with a higher renewable percentage than PG&E's portfolio, may be able to persuade these customers to take CCA service even if it means a higher bill for the customer.

- Tier 3 – 13.5 cents;
- Tier 4 – 21.1 cents; and
- Tier 5 – 25.1 cents.

Moreover, the degree of tiering in these generation rates was extreme, with the Tier 5 rate nearly six times the Tier 1 rate – despite the fact that it cost about 8.2 cents to serve usage in either tier. So Tier 1 usage was being charged just half the cost of generation, while Tier 5 usage was being charged more than triple the cost.

The actual amount that any particular customer paid for PG&E's generation depended on the customer's tier. For example, a customer with all of its usage in Tier 1 would pay just 5.2 cents (i.e., the Tier 1 generation rate). But a customer in Tier 4 or 5 could pay an average rate in the neighborhood of 15 cents per kWh.[29] Knowing this, MCE structured its new CCA to phase in its service in order to focus on the higher tier customers most likely to benefit from lower MCE bills. Per the legislation, a CCA provider is required to offer its service to all residential customers in its service area, and those that do not wish to take that service can opt-out and remain with PG&E. However, CPUC rules permitted a newly formed CCA like MCE to phase in its service. So, MCE targeted its program and, in its first phase of service, selectively enrolled just 10 percent of the eligible customers – predominantly the very largest users who were paying the highest PG&E generation rates. In total, there were approximately 55,000 eligible households in MCE's territory, with an average usage of 553 kWh per month. But in its first phase MCE served just 5,471 customers who, as a group, had an average usage of 1,433 kWh – nearly three times the overall average usage. By cherry picking just the very largest 10 percent of customers, MCE could offer a generation price just slightly below PG&E's (say, a little less than 15 cents) and still fully cover its costs with significant margins -- even if its own power costs exceeded PG&E's 8.2 cent figure.[30]

Prior to the advent of CCA service that could target customers based on their billed usage, this rate structure was sustainable. There were inequities, to be sure, with upper-tier consumers subsidizing lower-tier consumers, but the upper-tier consumers had little choice in the matter and could not escape. But once an alternative became

[29] The relationship between a customer's usage and its average generation rate is similar in shape to the one depicted for total rates shown in Figure 1. As usage increases, the average rate keeps increasing.
[30] Alternatively, MCE could charge the same generation rates as PG&E, but provide a "greener" power mix, and attract customers in that way.

available, in the form of MCE, PG&E lost most of these upper-tier users as generation customers,[31] along with the 15 cents per kWh of generation revenue they were paying. But PG&E's avoided generation costs were only about half this amount – resulting in a shortfall and the need to increase generation rates for its remaining bundled customers. The CPUC subsequently approved a flat, non-tiered, generation rate that addressed this distortion, and instead created the tiering in the total rate with a new rate component called the "Conservation Incentive Adjustment" (CIA) rate charged to all customers (CCA as well as bundled). However, during the almost two year "phase-in" period from May 2010 through February 2012, MCE accrued a windfall in revenues estimated at about $6 to $7 million per year at the expense of PG&E's remaining bundled customers.[32]

5. Challenges to Changing Current Rate Structures

The existence of many examples of non-cost-based rates leads to the question, "How and why did it get this way?" Historically, the absence of demand charges or TOU rates was a matter of customers not having the meters required to implement such rate structures in a cost-effective manner. Meters capable of measuring monthly maximum demands, or kWh usage by TOU period, were considerably more expensive than simple meters that measured just cumulated monthly kWh usage, so such rate designs were not economically feasible for residential and small commercial customers. But now that Smart Meters have been installed on the vast majority of PG&E's customers, those arguments no longer apply.

In many other instances, though, the approval of non-cost-based rate designs were conscious policy-driven decisions, with regulators and/or legislators wanting to provide discounts to particular groups of customers (e.g., low-income households) or to encourage particular technologies for environmental reasons (e.g., roof-top solar, electric vehicle charging). In still other instances, like inclining block tiered rates, the designs

[31] A small percentage opted out of MEA's service and remained as PG&E bundled service customers.
[32] The potential to gain by cherry picking high margin customers like those consuming in the upper tiers can go to either the supplier or to the customer, or be shared. Here, MCE as the only supplier had leverage, and priced its generation at, or just slightly below, PG&E's generation rate, effectively capturing the lion's share of the margin. A similar situation exists with solar vendors, who often have not had to price at cost in order to obtain business. In the Sacramento area, for example, there is evidence that solar companies charge more to customer served by PG&E (e.g., in Davis) than those served by SMUD (e.g., in Sacramento) due to Sacramento households having much lower upper-tier rates.

were initially implemented to provide all customers with a "baseline" amount of relatively inexpensive energy, and due to a perceived notion that this design encourages conservation.

But once distorted rates are in place and become the status quo, inertia sets in and constituencies develop for their perpetuation. In the aforementioned RROIR, there was opposition – from various interest groups -- to the implementation of a fixed charge, despite universal recognition by publicly owned utilities and other utility commissions across the country that fixed costs exist, better reflect cost of service, and are more equitable. There was similar opposition to reducing the number of tiers back to the two-tiered structure in place prior to the energy crisis, and to significantly reducing the rate differentials between tiers. But here, too, the opposition could not credibly claim that steeply-tiered rates were somehow cost-based. Rather, the primary arguments in opposition to both the fixed charge and to tier reform were policy-based: that these changes would discourage conservation and discourage the installation of on-site solar generation.

a. Effects of High Volumetric Rates on Conservation

Many of the arguments against the rate reforms proposed by the IOUs focused on upper-tier users and the allegedly strong conservation signal those customers would no longer see if their rates were reduced – and largely ignoring the fact that lower-tier users would now see a stronger conservation signal. Recent research, though, indicates that customers on tiered rates respond to the average rate they pay, not the marginal rate.[33] The implementation of a fixed charge and the narrowing of tier differentials both work to decrease the average rates of upper-tier users while increasing the average rates of lower-tier users. So the former group would be expected to increase their usage while the latter groups would decrease theirs. It is an empirical question which of these two effects dominates the other. PG&E and the other two California IOUs presented evidence that their proposed reforms would likely have no anti-conservation effect overall, and the CPUC concluded similarly. But even if the proposals were estimated to result in a slight increase in overall usage, why should that be so important?

[33] *See* Ito, Koichiro, "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing," American Economic Review, Vol. 104, No. 2, February 2014.

The pursuit of "conservation" as a goal in and of itself is an interesting phenomenon. Some interest groups that intervene in CPUC proceedings seem to believe it should be given far greater weight than the typical economist's objectives (i.e., that rates should be cost-based, efficient, and equitable). But why is that? After all, electricity is a product in great demand that people enjoy consuming. It enriches people's lives by allowing them to operate appliances, enjoy television shows, use the internet, refrigerate food and cool their homes. If a customer is willing to pay the cost of producing and delivering the electricity, why should she or he not be able to do so at a fair price? Yet customers who use too much electricity are deemed to be "wasteful" or "energy hogs" deserving of punitive rates for their "excessive" usage.[34]

A perfect example of this mentality occurred in hearings during PG&E's 2011 General Rate Case. While testifying in favor of continuing the steeply-tiered rate structure, the witness for one interest group responded to PG&E's attorney's questions as follows:[35]

> Q: *Is it your view that all Tier 4 customers are wasteful?*
>
> A: *Yes.*
>
> Q: *Were you here earlier today when we have had – or at other parts of the proceeding when we've had folks talk about how there are lots of ways to get into high tiers?*
>
> A: *Yes, we were.*
>
> Q: *And it's still your testimony that every single person that gets into Tier 4 is wasteful?*
>
> A: *By definition, Tier 4 are consumers that are using more than 300 percent of baseline. Therefore, the users that are using significantly more than baseline, we contend, are wasteful.*

Regardless of a household's situation, if they are consuming in Tier 4 they are wasteful. It does not matter if they might be a large, moderate income, family living in a poorly insulated house in the hot Central Valley for which air conditioning is essential. They should be punished with high upper-tier rates.

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[34] There also seems to be a widespread belief that it is acceptable to charge these high rates because high-usage customer also have high incomes. But while there is a positive correlation between income and usage, it is not a strong correlation. Consequently, many of the upper-tier consumers are moderate-income households (and, conversely, there are many high-income households in Tier 1 who are subsidized).

[35] Transcript from PG&E's 2011 General Rate Case Phase 2, November 19, 2010, pp. 797-798.

But a similar logic does not apply to the consumption of other goods. Take airline travel, for example. Airlines provide immense benefits to people, allowing them to travel to faraway places that they otherwise never would have been able to visit. But people who travel to lots of places are not shamed for their "excess" travel, told to stay at home and stop flying so much, or charged punitive air fares. Just the opposite, in fact: they are envied by others who wish they, too, could see the world, and rewarded by the airlines with frequent flyer miles -- an incentive to travel even more.[36]

Of course, there are environmental repercussions to consider, but those apply to airlines as well as electric utilities. The appropriate means to ensure environmental costs are accounted for is to internalize those costs for the supplier – not to distort the rate design. In the electric industry in California, greenhouse gas (GHG) emissions costs are already accounted for and included in rates, specifically in the generation component of the utilities' rates. With renewable portfolio standards, PG&E's power is already very clean and getting cleaner – with over 50 percent produced from non-GHG-emitting resources.[37] Shouldn't this make the pursuit of conservation, as an objective in and of itself, of diminishing importance?

Yet the appetite for charging above-cost, inequitable rates to top-tier users persists. As noted in Section 3a, the RROIR Decision created a new SUE tier that will go into effect in early 2017, applying to usage above 400 percent of baseline. Again, the rationale is not that such a rate is cost-justified, but apparently that a punitively high rate (which will eventually be 2.19 times the Tier 1 rate) is needed to incent conservation. But while it certainly provides a signal to conserve for those customers who reach that tier, it will provide the opposite signal for customers in the lower tiers – who will now have a reduced incentive to conserve (because the additional revenue from the SUE charge will be used to reduce lower-tier rates). No analysis was done on these offsetting

[36] Nor does the CPUC apply this logic to non-residential customers – most of which consume far more electricity than even upper-tier residential customers. Not a single PG&E non-residential customer faces an inclining block tiered rate, and every single one of them pays a monthly fixed charge. And for many water utilities under its regulation, fixed charges have been approved that collect 30 percent of total costs, with volumetric charges collecting the remaining 70 percent.

[37] The California Energy Commission's Power Content Label for PG&E 2014 showed a power mix with 27 percent eligible renewables, 8% hydro, and 21 percent nuclear, for a total of 56 percent that is GHG-free.

effects; rather, it was apparently driven by a desire to send a message to the "energy hogs" that they should use less.[38]

b. Effects of High Volumetric Rates on Solar Installations

In addition to conservation arguments, a number of parties – primarily solar interests, but also environmental groups – put forth arguments that the implementation of fixed charges and the narrowing of tier differentials runs counter to the public policy objective of encouraging rooftop solar. The argument is basically that this policy objective is more important than the objectives that rates should reflect cost, send accurate price signals, and be equitable. PG&E and the other IOUs presented evidence that these reforms would not prevent a continued healthy solar industry.[39]

But a more fundamental issue is whether changes to rate structures to make them more cost-based must always be tempered by the need to help a particular industry sell its product – no matter how environmentally friendly it may be. After all, solar can be added in other ways, like building central station plants, that may have a smaller cost impact, in terms of increasing non-solar customers' rates, than rooftop solar. And it is not like solar is an "infant industry;" it has had unprecedented growth in recent years. Finally, if the CPUC nevertheless is determined to subsidize solar by "taxing" customers, it should do so directly – transparently and with the affirmative understanding of customers -- through rebates and similar incentives – and not distort rates so that they hide the subsidies and send inaccurate price signals to customers.

c. Other Opposition to Rate Reform

Finally, a number of interest groups opposed various rate reforms for other reasons. For example, a prominent consumer advocate historically has argued for rate proposals that favor lower-tier users over upper-tier ones.[40] Other intervenor groups argue for continued high CARE discounts. So there are other interest groups, in addition to the environmental and solar groups, who like the current distorted rates just fine the way they are. These groups can be expected to continue to fight against more cost-based

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[38] The RROIR Decision describes it as follows: "…by using the term super-user electric surcharge, we believe that customers will be more likely to understand that their usage is in an extreme category and should be reduced." D.15-07-001, p. 127.

[39] For one thing, narrowing tier differentials has the effect of increasing lower-tier rates, which will increase the attractiveness of solar for customers consuming in those tiers.

[40] It was ORA that proposed the aforementioned cap that the RROIR Decision adopted, limiting the degree to which annual rate reform could increase Tier 1 rates. This cap, when triggered, results in upper-tier users having to pay higher rates to make up the shortfall.

rate designs, or at minimum delay their implementation for as long as possible, through policy inertia or litigation, with long transition periods and grandfathering. It has been, and will continue to be, a challenging process for each and every reform to move forward and become implemented.

5. Ideas for Making Rates More Supportable and Sustainable

To prevent further inefficient lost sales and resulting rate impacts on others, and to more fairly distribute the burden of fixed costs across lower users as well as higher ones, it is essential that rate designs be modified to reduce the extent to which costs are over-collected with volumetric energy charges and under-collected with fixed and demand charges. This section presents some specific ideas for rate proposals that would move in the right direction.

a. Narrow the Nominal Residential Tier Differentials

The RROR Decision prescribed a transition, or glide-path, through 2019 for reducing the number of tiers on residential rates, as well as narrowing the ratios between the rates themselves. These efforts are on the right track. However, there are two potential problems to achieving this that may need to be addressed in the future.

First, the decision also included a cap on the degree to which the Tier 1 rate could increase as tier differentials are narrowed.[41] This cap has already resulted in PG&E's rates making a detour from the 2016 glide path. Had the cap not existed, the 2016 rate reform glide path ratios would have resulted in PG&E's top-tier rate (for usage above 200 percent of baseline) dropping from 36.4 to 35.4 cents, narrowing the rate differential relative to the Tier 1 rate. However, because of the Tier 1 cap, the rate instead increased to 40.0 cents – a move in the wrong direction. While this may be a temporary setback, it may turn out in the future that the CPUC has to eliminate the Tier 1 rate cap if it wants to achieve the glide-path rate ratios by 2019.

Second, as described in Section 3.a, the RROIR Decision mandates that the rate ratios be calculated relative to the composite Tier 1 rate. So while the 2018 glide-path ratio between the Tier 2 rate (which in 2018 will apply to usage above baseline but below 400 percent of baseline) is 1.25 to 1, the actual, or nominal, rates will be farther apart

[41] Specifically, the Tier 1 rate may not increase (relative to its level twelve months prior) by more than the percentage increase in the residential average rate (over that same period) plus five percent.

than that. This is because any fixed charge or minimum bill amount revenue has to be counted as if it was Tier 1 revenue when calculating the composite Tier 1 rate. This has the effect of widening the ratio between the nominal Tier 1 and 2 rates. So long as fixed charge or minimum bill revenues are small – which they are today – this makes little difference. But if, in the future, a monthly fixed charge is adopted or the minimum bill amount is increased, it can have a significant effect.

Table 3 illustrates, using rates PG&E developed in April 2015, in response to an ALJ data request. Rates are shown for three of the requested scenarios, all of which collect the identical revenue requirement, to illustrate the effect of basing the rate ratios on the composite Tier 1 rate. For Scenario 1, the specification was that the rate ratio between the nominal Tier 2 and Tier 1 rates be set at 1.20,[42] with no monthly fixed charge. The resulting rates for Tiers 1 and 2 under that scenario were 19.6 and 23.5 cents, respectively, which have the specified 1.20 rate ratio in nominal terms. For Scenario 2, the same 1.20 ratio between the nominal Tier 2 and Tier 1 rates was specified, but here a monthly fixed charge of $10.42 (the most allowed by statute) was added to the rate structure. Comparing Scenario 2 to Scenario 1, we see that the additional revenue yielded by the fixed charge results in both the Tier 1 and 2 rates decreasing, while maintaining the 1.20 nominal rate ratio between them. In effect, the additional fixed charge revenue is used to proportionally decrease both rates. Finally, Scenario 3 has the same $10.42 monthly fixed charge, but is specified to have a 1.20 ratio between the nominal Tier 2 rate and the *composite* Tier 1 rate. A comparison of Scenarios 1 and 3 shows that, when the rate ratio rule is specified to be based on the composite Tier 1 rate rather than the nominal Tier 1 rate, the additional fixed charge revenue only reduces the Tier 1 rate, leaving the Tier 2 rate unchanged from what it would be in the absence of a fixed charge. And a comparison of Scenarios 2 and 3 shows that using the composite Tier 1 rate causes the ratio between the nominal Tier 2 and Tier 1 rates to increase dramatically to 1.47 – substantially higher than the glide-path ratio of 1.20.

[42] Nominal rates refer to the actual energy charges assessed to customer usage in each tier.

Table 3
Effect of Using Composite Tier 1 Rate to Set Residential Rates

Scenario	Glide-Path Rate Ratio Tier 2 : Tier 1	Monthly Fixed Charge	Tier 1 Rate (Nominal)	Tier 2 Rate (Nominal)	Rate Ratio (Nominal)
1	1.20 (Based on Nominal Tier 1 Rate)	$0.00	$0.196	$0.235	1.20
2	1.20 (Based on Nominal Tier 1 Rate)	$0.00	$0.178	$0.213	1.20
3	1.20 (Based on Composite Tier 1 Rate)	$10.42	$0.160	$0.235	1.47

Consequently, much of the benefit of adding the fixed charge in terms of providing bill relief to upper-tier consuming households, and reducing their bill volatility, is lost when the composite Tier 1 rate is used as the basis for the glide-path rate ratio. If true narrowing of tiered rates is to occur, the CPUC would need to modify this aspect of the decision in one of two ways: (1) by re-defining the glide-path rate ratios to be based on the nominal Tier 1 rate instead of the composite Tier 1 rate; or (2) continuing to base it on the composite Tier 1 rate, but reducing the glide-path rate ratio sufficiently below 1.20 to compensate and achieve a nominal rate ratio of 1.20.

b. Implement a Monthly Fixed Charge

The RROIR Decision, while noting that the fixed charge has merit with regard to making rates more cost-based, held off on implementing it until after the glide-path transition to fewer tiers with narrower tier differentials is achieved. In addition, the decision called for an additional proceeding to develop a consensus methodology for estimating the IOUs' fixed costs of providing residential electric service and developing a commensurate monthly fixed charge. Subsequently, the Commission has determined that PG&E's 2017 GRC Phase 2 case will be the proceeding for doing this. PG&E will be filing its proposed methodology along with the rest of its 2017 GRC Phase 2 proposals on June 30, 2016. The Commission should expedite this portion of the proceeding and quickly determine a methodology to be used, so that PG&E (and the other IOUs) may implement a fixed charge as soon as the glide-path end-state has been reached.

c. Increase the Minimum Delivery Charge

Prior to the RROIR Decision, PG&E had a minimum bill amount of $4.50 for its non-CARE customers.[43] The minimum bill amount was calculated in what is referred to here as the "traditional" manner: it was applied to the customer's total bundled bill. A customer's total bill was first calculated, and then compared to the $4.50 minimum bill amount. If the customer's bill was less than $4.50, it was "bumped up" to $4.50; otherwise, it was left unchanged. So the traditional minimum bill amount affected only very low usage customers – those whose bills would otherwise have been less than $4.50. During the RROIR proceeding, a number of parties argued that, instead of implementing a monthly fixed charge as the IOUs were proposing, the CPUC should use a traditional minimum bill amount to collect a portion of the residential fixed costs.

The RROIR Decision made three findings with respect to the minimum bill. First, the decision increased PG&E's traditional minimum bill amount from $4.50 to $10, beginning in 2015. PG&E implemented this increase in September 2015. Second, the decision directed that, in 2016, the methodology for calculating PG&E's minimum bill amount would change, and henceforth the $10 minimum bill amount would be applied to just the delivery portion of the customer's bill – with the generation portion calculated separately and not subject to a minimum bill.[44] PG&E implemented this new $10 Delivery Minimum Bill Amount in March 2106.[45] Third, and importantly, the RROIR Decision determined that the minimum bill amount is not subject to AB 327's $10 cap,[46] and could in the future be increased above the cap at the Commission's discretion.

During the proceeding, PG&E opposed the minimum bill amount, arguing instead that the Commission should implement a fixed charge. The traditional minimum bill amount has some serious drawbacks, and is vastly inferior to using a fixed charge for collecting residential fixed costs. First and foremost, it only applies to a small number of very low users. Given that PG&E's Tier 1 rate is currently 18.2 cents, a $10 minimum

[43] For CARE customers, it was $3.60.

[44] The generation portion of the bill is simply the generation rate (which does not vary by tier) multiplied by the customer's monthly usage. The delivery portion of the bill is then calculated by subtracting the generation portion from the total bundled bill.

[45] Under the delivery minimum bill methodology, the delivery portion of the customer's bill is calculated separately from the generation portion. If the delivery portion is less than $10, it is bumped up to the $10 minimum level; otherwise, it is left unchanged. Then the generation portion is added in to get the total customer bill.

[46] While it is referred to here as the "$10 cap," the amount of the cap actually increases with inflation.

bill amount would apply only to customers using 55 kWh or less in a given month.[47] Only a very small percentage of PG&E's customers fall into that category.[48] So a traditional minimum bill amount collects very little revenue, and thus has little ability to help reduce the artificially high volumetric rates. In contrast, a $10 monthly fixed charge would apply to every single customer, collect hundreds of millions of dollars of revenue, and thus "fund" significant decreases in volumetric rates. In addition, the traditional minimum bill amount sends a perverse price signal to very low usage customers, since all customers using less than 55 kWh will be charged $10 – whether they use 55 kWh in a month or nothing at all. Thus there is no incentive for a low user to conserve, because all kWh consumed from zero up to 55 kWh result in the identical bill.

But, with the switch from the traditional minimum bill amount to the Delivery Minimum Bill Amount now in effect, many of the drawbacks of minimum bills have been eliminated, or at least mitigated. At the current $10 amount, the Delivery Minimum Bill Amount still does not collect anywhere close to the revenue that would be obtained from a $10 fixed charge (though it collects more than the traditional minimum bill amount did). However, in determining that the $10 statutory cap does not apply to minimum bills, the RROIR Decision left the door open for this charge to be increased above $10 in the future – unlike the fixed charge. At higher levels, it would begin to collect significantly greater revenues that would provide meaningful reductions in volumetric charges.[49] Finally, it avoids the perverse incentive where, for low users, additional kWh can be consumed with no increase to bills. Since the generation portion of the bill is calculated independently of the Delivery Minimum Bill Amount, additional kWh consumption will always result in a higher bill. Proposals to increase the $10 Delivery Minimum Bill Amount would be a step in the right direction, collecting greater proportions of fixed costs from lower-tier consumers who currently are avoiding paying their fair share of those costs.

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[47] This minimum bill amount kWh threshold is calculated by dividing the $10 per month minimum bill amount by the $0.182 per kWh rate.

[48] Furthermore, even among those who do, the $10 minimum bill amount may only collect a small amount of additional revenue. For example, in the absence of a minimum bill, a customer who uses 50 kWh would have a bill of $9.10 in any event, so the implementation of the $10 minimum bill amount would collect only $0.90 in additional revenue from the customer.

[49] Although the problem noted earlier resulting from the requirement to base rate ratios on the composite Tier 1 rate would still need to be addressed.

d. Optional Cost-Based Rates for Residential and Small Commercial

As described earlier, PG&E's small commercial customers are served on rates without demand charges, although those rates do have TOU energy charges. None of the residential rate schedules have demand charges or even monthly fixed charges, and while residential customers have the option of volunteering for schedules with TOU energy charges, only a small fraction have done so to date. Thus, there is an opportunity to these two customer classes more cost-based rates, which include a fixed charge, a demand charge, and TOU energy charges. In its upcoming 2017 GRC Phase 2 proceeding, PG&E plans to propose such rates for both customer classes. The rates would be made available on an optional basis, and customers would be able to opt in if they desire. This would allow those who opt in to face a mixture of fixed and variable price signals which more accurately reflect the costs incurred by PG&E to provide their service, and in particular would benefit higher users and/or higher load factor customers who today are subsidizing their neighbors.

The TOU energy charges on these rates will provide incentives for customers to reduce their bills by shifting loads from high-cost to low-cost periods, and the resulting reduction in PG&E's costs will benefit all customers in the form of lower rates. In addition, the demand charges will provide incentives for customers to better manage their loads (i.e., stagger appliance/equipment use so as to not have them all on at the same time) to achieve bill savings. The demand charges will also open up opportunities for customers to save by installing battery storage that will enable them to shave loads and save on their bills, as well as to shift loads and benefit from the TOU rates.

e. Modify TOU Periods for Non-Residential Customers

As noted in Section 3.e, the old TOU period definitions, with peak hours from noon to 6 p.m., are now obsolete. These afternoon hours are no longer the high-cost hours; rather, the high-cost period has shifted to later in the day. PG&E has already obtained approval to move its peak period for residential customers to 4 p.m. to 9 p.m. In PG&E's upcoming 2017 GRC Phase 2 proceeding, PG&E will be proposing similar, later in the day peak period hours for non-residential customers. This is important because, today, those customers are receiving the perverse price signal to begin using more electricity at 6 p.m. But the period from 6 p.m. through the next several hours is precisely when costs are now the highest. So it is critical that the new period definition be implemented as soon as possible, to guide customers' consumption decisions over the hours of the day, and also to encourage appropriate investments based on the new price signals.[50]

TOU rates are mandatory for PG&E's non-residential customers, and there are likely to be some who will see higher bills under the new TOU period definitions. These bill impacts can be mitigated somewhat by starting with milder peak vs. off-peak price differentials, and gradually increasing them over time to better reflect costs. But it is important, for the reason described in the previous paragraph, that customer groups not be grandfathered onto rates with the obsolete TOU period definitions that no longer reflect the new cost reality simply because they have adverse bill impacts or happen to have made certain investments (e.g., in on-site solar generation). As a fallback, in the event the CPUC does end up grandfathering customers onto rates with the noon to 6 p.m. peak hours, it is absolutely essential that the rate levels themselves reflect the new hourly cost patterns during those now-obsolete hours. Since hourly costs are now lower during the noon to 6 p.m. period than before, the "peak" rate will decrease from today's level. Similarly, since hourly costs are now higher during the evening hours, the "off-peak" rate will increase. So if, for grandfathering purposes, TOU schedules with the current definitions are retained, we might see the seemingly perverse set of rates where the "off-peak" rates exceed the "peak" rates. But it will not be the rates that are perverse. Rather, it will be the TOU period definitions that are perverse, and the seemingly strange rates would just be the logical result of having to design rates to reflect costs to the greatest extent possible given the constraint of having to use the inappropriate TOU period definitions.

6. Conclusion

This paper has described the current state of PG&E's electric rate structures, and the over-reliance on the use of volumetric rates to collect fixed and capacity-related costs. The consequences are not just large subsidies from some customer groups to others, but an increasingly less supportable and sustainable rate structure now that customers are more sophisticated and have alternatives – as demonstrated by recent trends of declining

[50] For example, customers installing on-site solar units will be incented to install them pointing south-west, or even west, to maximize value to themselves and the grid, and not south to maximize generated kWh.

sales growth resulting in upward rate pressure. The paper has presented a number of ideas for proposals which, if approved and implemented, would help mitigate the situation. While there are large challenges to changing this situation, in the form of intervenor groups who, for various reasons, prefer the status quo, the recent trend in sales loss highlights the need for action. It is past time to start providing customers rates that better reflect utility costs and send more accurate more price signals to guide their consumption behavior, as well as their decisions to invest in new technologies like energy storage to better manage their loads and decrease utility costs and rates.