Impacts of Time-of-Use Rate Changes on the Electricity Bills of Commercial Consumers

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I. INTRODUCTION

The advent of distributed solar, catalyzed by decreased capital costs and programs such as net energy metering (NEM), has caused a shift in the profile of prices in wholesale electricity markets: prices are lower during times of peak solar generation (i.e., midday) and higher during times of peak demand (i.e., early evening) [1]. For electric utilities that offer flat time-of-use (TOU) rates, this change can be problematic, especially if their TOU periods are poorly aligned with the prices observed in the wholesale markets [2], [3]. In recent years, utilities such as Pacific Gas and Electric Company (PG&E) have worked to better align their TOU rates with the prices observed on the wholesale markets so as to better ensure cost recovery [4].

However, restructuring these rates can have a significant impact on a consumer’s total electricity bill and on its ability to reduce its electricity cost using distributed energy resources (DERs) [2], [5], [6]. Shifting TOU periods to align more closely with prices on the wholesale market affects consumers differently depending on the shape of their demand profile and on the types and sizes of the DERs they have deployed. For consumers with distributed solar, realigning TOU periods to occur later in the day undoubtedly reduces the benefits of NEM [2]. As the ability of programs like NEM to provide cost savings decreases, consumers who seek to reduce their electricity bills will need to make their demand more flexible, perhaps by installing energy storage or implementing price-based demand response.

In this paper, we explore the impact that PG&E’s redesigned tariffs have on the total electricity bills of commercial consumers with different demand profiles. To adequately explore this impact, an optimization model is created that determines the minimum total bill for consumers with a combination of PV and battery energy storage (BES) assets. This model allows the total bills under existing tariffs to be juxtaposed with those under the redesigned rates. Through sensitivity analyses, we are also able to examine how the size of these assets reduces cost under each tariff.

The rest of this paper is organized as follows. Section II provides an overview of the PG&E tariffs explored in this paper. Section III presents the mathematical formulation used to minimize the electricity bill of a commercial consumer with a combination of PV and BES assets. Section IV introduces case studies of two different consumer types that are eligible for the existing and redesigned PG&E tariffs. The correspond-
ing electricity bills, asset values, and cost sensitivities are discussed for combinations of consumer assets and tariffs. Section V concludes the paper.

II. OVERVIEW OF PG&E TARIFFS

As of 2020, two main electric tariffs that PG&E offers its commercial consumers are the E-19 and B-19 rate schedules [4], [7]. Beginning in November 2019, B-19 rates became available on a voluntary basis, with the intent to replace the longstanding E-19 rates in March 2021. While both tariffs offer TOU rate schedules, the E-19 and B-19 tariffs are significantly different. Many of these differences indicate a shift towards PG&E’s rates becoming more coincident with current wholesale market prices. One difference is that compared with the E-19 rates, the peak and partial-peak rates under B-19 are much later in the day. For instance, peak rates (i.e., the most expensive rates) under B-19 occur from 4pm to 9pm, rather than between 12pm and 6pm for E-19. Depending on their demand profile, this shift has obvious cost implications for consumers. Consumers participating in NEM are also affected, as the higher sell rates are less aligned with times of peak solar generation. The B-19 tariff also includes a new ‘super off-peak’ rate, which occurs from 9am to 2pm during spring months and features the lowest energy prices. While potentially beneficial for consumers with midday demand peaks, these rates can hurt the sell rate for NEM participants. Finally, unlike the E-19 tariff, where the off-peak rates (i.e., the cheapest rates) were effective all day on weekends and holidays, the B-19 tariff implements TOU pricing every day of the week. Consumers who may have once found price relief on weekends will need to incorporate more intra-day flexibility to find similar relief under B-19 rates.

In this paper, we consider multiple rate options available under the E-19 and B-19 tariffs. Both tariffs offer base TOU rates and Option R for Solar (OpR) rates. OpR rates are available to consumers with PV systems that provide at least 15% of their annual energy. Under the OpR rates, demand charges are lower than the base TOU rates, while energy charges are higher. The B-19 tariff also offers the Option S for Storage (OpS) rate, which is available to consumers with BES installations that have power ratings of at least 10% of the consumer’s maximum annual demand. The OpS rate imposes low demand charges on daily demand and demand during the typical TOU periods; consumers with sufficient flexibility have the potential to significantly reduce their monthly demand charges. The OpS rate features the same higher energy charges introduced under the OpR rates [4], [7].

III. MATHEMATICAL FORMULATION

We define a linear program (LP) to determine the minimum monthly electricity bill, comprised of costs associated with TOU rates and revenues associated with NEM, for a consumer that has a combination of PV and BES assets. Within the LP, BES operation is optimized to achieve the minimum bill, while simulated demand [8] and PV generation [9] are provided as parameters. To obtain a consumer’s total annual electricity bill, the LP is run twelve times. The LP is formulated as follows:

\[
\min_{} \ D_{max} \cdot DR_{max} + \sum_{p \in P} D_{tou}(p) \cdot DR_{tou}(p)
\]

\[
+ \frac{1}{4} \cdot \sum_{t \in T} D_{net}(t) \cdot ER(t)
\]

\[
+ \frac{1}{4} \cdot \sum_{t \in T} [D_{net}(t) - D_{net}^+(t)] \cdot NSR(t)
\]

subject to:

\[
D_{net}(t) \leq D_{max}, \quad \forall t
\]

\[
\delta(t, p) \cdot D_{net}(t) \leq D_{tou}(p), \quad \forall t, \forall p
\]

\[
D_{net}^+(t) \geq 0, \quad \forall t
\]

\[
D_{net}^+(t) \geq D_{net}(t), \quad \forall t
\]

\[
J(t) = J(t - 1) + \frac{1}{4} \cdot [\eta \cdot P_{cha}(t) - P_{dis}(t)], \quad \forall t > 0
\]

\[
J(t) = J_{init} + \frac{1}{4} \cdot [\eta \cdot P_{cha}(t) - P_{dis}(t)], \quad t = 0
\]

\[
J(T) = J_{init}
\]

\[
J_{min} \leq J(t) \leq J_{max}, \quad \forall t
\]

\[
\frac{1}{4} \cdot \eta \cdot P_{cha}(t) \leq BER - J(t - 1), \quad \forall t > 0
\]

\[
\frac{1}{4} \cdot \eta \cdot P_{cha}(t) \leq BER - J_{init}, \quad t = 0
\]

\[
\frac{1}{4} \cdot P_{dis}(t) \leq J(t - 1), \quad \forall t > 0
\]

\[
\frac{1}{4} \cdot P_{dis}(t) \leq J_{init}, \quad t = 0
\]

\[
P_{cha}(t) + P_{dis}(t) \leq BPR, \quad \forall t
\]

\[
D_{base}(t) + P_{cha}(t) \geq P_{dis}(t), \quad \forall t
\]

where

\[
D_{net}(t) = D_{base}(t) - P_{pv}(t) + P_{cha}(t) - P_{dis}(t), \quad \forall t
\]

Equation (11) is the objective function and reflects the consumer’s total electricity bill. The first line of the objective function pertains to a tariff’s demand charges, where the first product is the demand charge associated with the maximum monthly demand and the summation of products determines the demand charges for maximum demand during each TOU period. The second line represents the consumer’s energy charge and the third line represents the NEM revenue, where the difference represents the consumer’s net export to the grid. The NEM sell rate, NSR, equals the energy rate minus a non-bypassable charge, which is approximately $0.02/kWh - $0.03/kWh [10]. The \(\frac{1}{4}\) multiplier is required because the integration uses a 15-minute time step; this multiplier is included on energy quantities throughout this paper. Constraints (2) and (3) define the maximum demand terms [11]. The \(\delta\) in Constraint (3) is an indicator variable that equals ‘1’ when \(t\) aligns with the TOU period, \(p\), and ‘0’ otherwise. Constraints
We consider two archetypal consumers to assess the impacts of the PG&E rate redesign: a consumer with morning-and-evening peaking (MEP) demand and a consumer with midday peaking (MDP) demand. The MEP consumer has a maximum demand of 220.9 kW and the MDP consumer has a maximum demand of 326.5 kW. The load profiles for each consumer are adapted from data made available by OpenEI [8]. Each consumer has a PV system and a two-hour BES. The MEP consumer has a 231.8-kW PV system and a 250-kW BES, while the MDP consumer has a 340.7-kW PV system and a 350-kW BES. Asset sizes are selected so that both consumers have similar ratios of asset size to maximum demand.

The consumers are exposed to each of the PG&E rates discussed in Section III:

- E-19 base TOU tariff (E19TOU)
- E-19 Option R for Solar tariff (E19OpR)
- B-19 base TOU tariff (B19TOU)
- B-19 Option R for Solar tariff (B19OpR)
- B-19 Option S for Storage tariff (B19OpS)

In the following subsections, we examine the impact that these tariffs have on the consumers’ total bills and the value added by a BES as the sizes of the consumers’ assets are varied.

A. Impact on Total Electricity Bill

As discussed in Section II a tariff’s TOU periods and demand and energy charges can have a drastic impact on a consumer’s total bill. However, the nuances of each tariff can also influence the ability of a consumer’s DERs to achieve cost reductions. To understand these interactions, we perform sensitivity analyses for each consumer to examine the sensitivity of their total bill to the size of the assets under each of the five tariffs. We consider four scenarios:

1) a sweep of the consumer’s PV system capacity when the consumer does not have a BES,
2) a sweep of the consumer’s PV system capacity when the consumer has the two-hour BES described at the beginning of Section IV,
3) a sweep of the consumer’s two-hour BES capacity when the consumer has the PV system described at the beginning of Section IV,
4) a sweep of a four-hour BES capacity (replacing the consumer’s two-hour BES) when the consumer has the PV system described at the beginning of Section IV.

IV. CASE STUDIES

Figure 1 shows the results of these sensitivity analyses. Figures 1a – 1d show the MEP consumer’s results and Figures 1e – 1h show the MDP consumer’s results. Since E19TOU is the current base tariff, we present the total bill for each case relative to the total bill under E19TOU.

It is apparent that the demand profile determines how favorable a particular tariff might be for a given consumer. Figures 1a – 1d show that the B-19 tariffs are almost always more expensive for the MEP consumer than the E-19 tariffs, which can be attributed to B-19’s later peak and partial-peak demand periods aligning with the MEP consumer’s evening demand peaks; under the E-19 rates, the MEP consumer is largely insulated from the peak demand period prices. Conversely, Figures 1c – 1f show that the B-19 tariffs produce lower total bills than the E-19 tariffs for the MDP consumer, particularly for smaller relative asset sizes.

PV system sizing plays a large role in reducing costs for the MEP consumer. Figures 1a and 1b show that E19OpR generally produces lower total bills for the MEP consumer, especially as the PV system size increases. E19OpR, and E19TOU to a lesser extent, outperforms the B-19 rates in large part because of the higher energy rates that coincide with the times of peak solar generation. This allows the MEP consumer to sell excess solar generation through NEM at a higher rate. Consumers with larger PV systems will have more excess power to sell, thereby achieving larger cost reductions. A similar result is not observed when the MEP consumer participates under the B-19 rates because the later peak period does not coincide with the peak solar generation times. Instead of taking advantage of the higher energy rates to sell excess solar generation, the consumer is simply forced to pay a higher energy charge. PV system size has a much smaller impact on the total bill of the MDP consumer, as evidenced by the insensitive total bills observed in Figures 1e and 1f. The total bill under E19OpR is the noticeable exception, which is to be expected due to the tariff’s reliance on selling back excess generation to create cost reductions.

BES sizing appears to have a sizable impact on the total bills of both consumers. For the MEP consumer, Figures 1c and 1d show that total bills are very sensitive to changes in BES capacity when the consumer is participating under B19OpS. This makes sense due to the multiple smaller demand periods to which the consumer is exposed under B19OpS. B19OpS rewards consumers for having more flexibility, be it through BES with larger capacities or longer durations. Figure 1e shows that the larger capacity for the two-hour BES results in a total bill closer to that obtained under E19TOU. As seen in Figure 1d having a BES with a longer duration and a high capacity can result in a total bill that is even lower than that obtained under E19TOU. A similar result is observed for the MDP consumer, where Figures 1g and 1h show that total bills obtained under B19OpS are most sensitive to changes in BES capacity. The difference is that
participating under B19OpS clearly produces the lowest total bill, due to low demand charges and peak solar generation during times of maximum demand. This overlap allows the BES to simultaneously minimize demand charges and increase the amount of excess solar generation that is sold through NEM; BES with larger capacities and a longer duration are best equipped to take advantage of this overlap. It should be noted that Figure 1h shows an interesting result, where the four-hour BES with the largest capacity yields the smallest total bill under E19OpR. This likely occurs because the BES is so large that the MDP consumer is able to both sell back large amounts of solar generation, thereby producing large cost reductions through NEM, and adequately shift demand out of peak pricing times.

B. Value Added by a Battery

As was discussed in Section IV-A the flexibility provided by a consumer’s BES produces similar, if not lower, total bills under the B-19 rates, particularly B19OpS, when compared with the E-19 rates. The apparent need for increased intra-day flexibility will likely make BES a more attractive option to commercial consumers, especially as BES capital costs continue to fall. Knowing this, it is useful to quantify the value that a BES provides to a consumer. Using the results from Section IV-A, we calculate the battery value added (BVA) for each consumer under each tariff. BVA is calculated by subtracting a consumer’s total bill with a combination of PV and BES from the same consumer’s total bill without BES (but with the same PV capacity). Figure 2 shows the BVA for each consumer and a sweep of each asset capacity. Since E19TOU is the current base tariff, we present the BVA results relative to the BVA realized under E19TOU.

As Figure 2 shows, the tariff under which a consumer takes service has a large impact on the observed BVA. It is clear that consumers taking service under B19OpS generally have the highest BVA, regardless of the consumer’s demand profile. This can be largely attributed to B19OpS better rewarding consumer flexibility. Despite E19OpR frequently producing some of the lowest total bills, we see that E19OpR has some of the lowest BVA totals. As previously discussed, E19OpR’s reliance on selling excess solar generation to remain cost competitive indicates that the PV system likely has a greater impact on a consumer’s cost reductions.

Additionally, the BVA follows similar trends across consumers as asset sizes are varied. Figures 2a and 2d indicate that BVA performs better relative to E19TOU’s BVA as PV capacity decreases. This makes sense because the BES is increasingly relied upon to create cost reductions as the PV system gets smaller. However, this trend does not hold for the MDP consumer under B19OpR, where the relative BVA declines as PV system decreases. Under B19OpR, where the high price period does not coincide with the MDP consumer’s peak demand and peak solar generation, declining PV capacity makes it increasingly difficult for the BES to both reduce the consumer’s demand peaks and shift demand from the high-priced periods. Figures 2b and 2e show that BVA relative to E19TOU’s BVA generally declines as capacity decreases,
with the BVA obtained under E19TOU being greatest for two-hour BES with low capacities. Although a similar trend is observed in Figures 2c and 2f for a four-hour BES, where relative BVA declines with declining BES capacity, we see that the longer duration BES always achieves the greatest BVA under B19OpS, even for the smallest BES capacities.

V. CONCLUSIONS

This paper shows the impacts that PG&E’s rate redesign can have on consumers with different demand profiles. Without on-site generation or demand flexibility, consumers with demand peaks that are coincident with peak pricing periods will predictably have higher electricity bills. Under PG&E’s rate redesign, it appears that consumers with evening demand peaks stand to be the most adversely affected. However, we see that DERs, particularly BES installations, have the ability to shield consumers from the shifted TOU periods.

While the models used in this paper assume perfect foresight and do not consider BES degradation, we believe the impact of the results are not diminished. The LP described in Section III does not seek to accurately forecast a consumer’s true bill, which is outside the scope of this work. Instead, determining a lower bound on the consumer’s bill, where all actions are truly optimal, is sufficient for examining the impacts of PG&E’s rate redesign. BES degradation is not considered because the number of BES cycles averaged close to one per day.

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