BEST PRACTICES FOR COMMERCIAL AND INDUSTRIAL EV RATES

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INTRODUCTION

Electric vehicles (EVs) are an essential tool in reducing transportation sector greenhouse gas emissions, while also potentially lowering electricity costs for all customers. The key to unlocking these benefits lies in thoughtful rate design, which can foster greater EV adoption and encourage EV charging during hours when the grid's capacity is underutilized.

Unfortunately, traditional commercial and industrial (C&I) electricity rates can present a barrier to EV adoption by erasing the EV fuel cost savings relative to gasoline or diesel. Traditional C&I rates were generally designed for large buildings, rather than for public fast charging of passenger vehicles or for depot charging of truck and bus fleets. Accordingly, those rates do not reflect the unique costs or flexibility of EV charging and can charge commercial EV customers much more than their true cost of service.

This paper discusses strategies that can be used to design EV rates for the C&I sector that balance multiple objectives:

- Provide appropriate price signals to maximize benefits for the wider grid;
- Encourage EV adoption by ensuring the economics of transportation electrification are not artificially undermined; and
- Provide rate options that work for multiple types of customers, recognizing that the ability to shift charging load varies across use cases.

Subsidizing EV customers on existing C&I rates through "discounts" is not a sustainable solution. Instead, utilities and their regulators should develop new C&I rates designed with EV use cases in mind that are cost-reflective and take advantage of the unique characteristics and flexible nature of EV charging.

In summary, we recommend the principles to the right for rate design for EV customers in the C&I sector:

1. Rates should be designed to promote efficient use of fixed system resources, which will lead to reduced costs for all utility customers.
2. Rates should be easy to understand and predictable.
3. Rates should be designed with end users in mind.
4. Time-varying volumetric rates are generally preferable to demand charges.
5. Non-coincident peak demand charges should generally be avoided.
6. It may be appropriate to set rates to recover marginal costs rather than embedded costs; rates that recover marginal costs prevent new EV load from increasing costs for other customers, while promoting adoption of EVs.
7. Programs that rely on the price signals inherent in rate design to deliver grid and user benefits should ensure users actually see those price signals. If signals are not passed through to the drivers who decide when to charge, then charging behavior will not be affected and neither grid nor user will benefit.

EMBEDDED VS. MARGINAL COSTS

Embedded costs reflect the historical expenditures already made to construct the existing grid that are slowly depreciated over time, while marginal costs are the incremental costs associated with serving additional load.[1] On the whole, the revenue collected from all customers through rates must equal the utility's total cost of providing service, which includes the undepreciated embedded costs.

The standard approach is to recover embedded costs from all customers based on each customer class's contribution to costs. However, there are several important reasons that regulators may choose to set rates at marginal cost (or somewhere below embedded costs) for EV customers in the near term.

Aligning rates with the marginal cost of serving new commercial EV load provides customers with fuel cost savings that help encourage greater EV adoption. Greater commercial EV adoption not only promotes emissions reductions and the achievement of state climate, equity, and air quality goals—but also the integration of incremental load which can help put downward pressure on rates to the benefit of all electricity customers. Commercial EV charging is generally a new type of load on the system. Incentivizing fuel switching from historically gasoline- or diesel-powered vehicles presents an opportunity to bring incremental load onto the grid and spread the fixed costs of the system over a greater volume of electricity sales. This puts downward pressure on rates for all electricity customers. However, significant levels of fuel switching and the resulting downward pressure on rates will not materialize unless the rates available to commercial EV drivers are cost-competitive with gasoline or diesel.

Setting rates at marginal cost, as has historically been done for economic development and business attraction rates, would incentivize greater commercial EV adoption and recruitment of incremental load during the critical developing years of the commercial EV market. It would also better reflect the true cost of serving new commercial EV load on the system during those years. Since utility revenue requirements are largely reflective of historical expenditures, rates are typically set to recover embedded costs. However, the historical investments in the grid (embedded costs) exist regardless of this new EV charging load and were not incurred because of it, so setting rates at marginal cost better reflects the actual cost new commercial EV load imposes on the system during the initial years. Over the long term, however, marginal costs become embedded costs, and it is appropriate to gradually transition to recovering embedded costs from EV customers. As long as rates are set to recover at least marginal costs, existing customers will bear no additional costs from bringing this new load onto the system, while benefitting in the long term from downward pressure on rates due to the addition of incremental commercial EV load onto the grid.

Downward pressure on rates from widespread EV adoption has already been observed in the real world. Between 2012 and 2018, EV customers in the two utility service territories with the most EVs in the United States contributed nearly $600 million in excess of associated costs, putting downward pressure on electricity rates for all customers. This has long been the primary justification for economic development rates, which offer temporary pricing below embedded costs to attract new load. As explained by Professor Phillips in *The Regulation of Public Utilities*, such pricing strategies are often socially desirable. By allowing a utility to "expand its sales and utilize its facilities more fully, average costs are reduced as fixed costs are spread over more units of output… [which] may result in lower prices for *all* customers and in wider use of the utility's services."[2]

[1] In some jurisdictions, individual customers are required to bear the costs of interconnection and/or distribution system upgrades associated with new EV load. In such instances, care must be taken in rate design to ensure that these customers are not being charged twice for the same infrastructure costs.

[2] Charles Phillips, *The Regulation of Public Utilities: Theory and Practice*, 3rd ed. (Public Utilities Reports, 1993), 438.

TYPES OF CHARGES IN AN ELECTRIC BILL

Electric utilities can recover the costs of maintaining the grid and generating or purchasing power through a variety of different charges. In this section, we provide a brief review of several common billing elements. In the following sections, we discuss how these elements can be most effectively deployed to maximize benefits from C&I EV load.

VOLUMETRIC CHARGES

Volumetric charges are assessed based on the amount of energy a customer consumes. These rates can be flat, or they can vary by hour and day of the week. The most common form of time-varying rates is the time-of-use (TOU) rate. TOU rates reflect the approximate cost of providing energy in different hours of the day, with higher prices for "on-peak" hours and lower prices for "off-peak" hours. By disincentivizing electricity consumption during peak hours, TOU rates help to reduce overall system costs. Many existing C&I rates are TOU rates, but they were not designed with EV users in mind.

DEMAND CHARGES

Demand charges are common for C&I customers. These charges are typically based on a customer's maximum usage (peak demand) during a month and are intended to recover costs associated with equipment that is sized based on peak demand.

There are two types of demand charges: coincident and non-coincident. Coincident demand charges are assessed based on customer peak demand during time periods when the system tends to encounter its highest demand. These charges are most appropriate for recovering the costs of equipment that serve many customers and must be sized to meet the aggregate demand for a large area. Non-coincident demand charges are based on the customer's highest recorded demand in any hour. These types of demand charges are most appropriate for recovering the costs of equipment sized to meet the specific customer's peak demand, regardless of when that occurs.

CRITICAL PEAK PRICING

Critical peak pricing (CPP) assesses an extremely high price during only a small number of event hours per year when the system is most stressed. Customers are typically notified the day before an event. For example, a utility may call five CPP events during the year, each of which lasts between two and four hours. During the events, electricity might be priced 10 times higher than the average rate. CPP can be easily layered on top of a standard TOU rate.

CPP serves a function that is similar to demand charges. Some large grid costs, such as generation capacity and transmission costs, are primarily driven by only a few hours of the year during which load is highest. As a result, charging very high prices for each unit of energy consumed during system-wide peaks can accurately reflect the costs that customers impose on the grid. In exchange, electric rates at all other hours are a little lower.

FIXED CHARGES

Fixed charges, or customer charges, do not depend on a customer's electricity consumption patterns at all. Instead, they appear as a constant charge each month. These charges seek to recover costs that are independent of consumption, such as metering expenses.

DESIGNING RATES FOR C&I EV CUSTOMERS

A core purpose of rate design is to promote efficient use of the system. Rates promote efficient use by sending *effective* price signals – that is, signals that are cost-reflective, simple, and actionable. In other words, to promote efficient use of the system, customers should be charged accurately for the costs that they impose, while ensuring that rates remain simple and structured in a fashion that enables behavioral response. Additionally, rates for C&I EV customers should consider the impacts on transportation electrification to ensure that the economics of EV charging are not artificially undermined. In practice, these principles mean that rates should take into account the sophistication of the users and the ability of users to respond, as well as the extent to which price signals accurately convey system costs. Overly complicated or volatile rates may provide confusing incentives or otherwise provide price signals that are not actionable. Therefore:

- Simple TOU rates may be more effective than more volatile hourly pricing for many customers, since they are predictable and easy to understand.
- TOU rates can also be used in lieu of demand charges, particularly for those costs on the system that are driven by coincident demand. In fact, TOU rates can improve cost reflectivity of rates, since they better capture the duration of time that a customer is using shared infrastructure during peak periods instead of only focusing on a customer's single hour of maximum demand. As public utility economists have long recognized, "the longer the period of time that customers pre-empt the use of capacity [by other customers], the more they should pay for the use of that capacity."[3] A time-varying energy rate charges a customer more for using the distribution system more extensively during peak hours, but a demand charge – even a coincident demand charge, cannot capture this.
- TOU rates facilitate public charging stations' ability to convey price signals to drivers using the station far better than demand charges.
- Demand charges should be avoided for customers with low load factors, as they represent a disproportionate share of these customers' bills and can present an obstacle to transportation electrification.

In the next section, we describe important considerations for two common types of C&I EV customers –public DC fast charging stations and fleet vehicles. These descriptions are not meant to be exhaustive; rather, they are meant to provide examples of the different characteristics of the EV customers that utilities seek to serve. Utilities will need to work with the customers in their service territories to learn more about their operations and how rate structures can be designed to be both cost-reflective and actionable.

PUBLIC DC FAST CHARGING STATIONS

Public EV charging stations represent one important category of new C&I EV load. Here, we focus particularly on public DC fast charging stations, though our observations are likely to apply to all public charging installations. Fast charging stations operate somewhat similarly to gas stations – they provide a quick recharge when drivers are on the road or have limited access to charging at home and work. DC fast chargers need to be able to provide large amounts of power, with the newest stations charging vehicles at up to 350 kW. As EVs capable of charging at these fast stations become more common, more of these high-powered stations will be needed.

Public DC fast charging stations may have particular difficulty responding to dynamic rates – those that fluctuate on an hourly basis rather than varying according to a predictable preset schedule. Examples of such rates include hourly pricing (in which the hourly prices are not known until a day in advance), and critical peak pricing (in which a critical peak event is not announced until a day in advance).

Public DC fast charging stations are generally reluctant to charge their customers (the EV drivers) dynamic rates, since EV drivers prefer predictable and relatively stable electricity prices. Since DC fast charging customers may be traveling, it is difficult to warn them ahead of time in the event of a

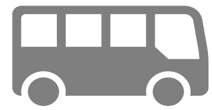
[3] Garfield, Paul J. and Lovejoy, Wallace F. (1964) Public Utility Economics at 163.

critical peak period, as they may live outside of the utility's service territory. Thus, dynamic rates are less likely to be translated into prices that EV drivers will see when using the charging station, thereby erasing the effectiveness of the price signal.

Similarly, DC fast charging stations may have difficulty throttling load to reduce demand charges, since EV drivers expect to be able to charge their vehicles as quickly as possible. Sensitivity to demand charges is likely to be even greater for fast charging stations with low load factors, such as those on more remote corridors. Investment in such stations, essential though it may be to make transportation electrification viable, could be disincentivized by a demand-based rate design that imposed disproportionate costs on these low load factor stations.

In some cases, it may be possible for fast charging stations to install stationary battery storage to shift load. Battery storage may be particularly effective at avoiding critical peak pricing and demand charges by powering the charging station from the battery instead of the grid for a few hours. However, battery storage is very expensive and the locations in which it can be installed are limited due to space constraints.

In light of these challenges, rate designs for EV fast charging stations should impose demand charges and critical peak prices only to the extent absolutely necessary, and instead recover costs through more predictable rates where possible. TOU energy rates may be a good alternative approach, since these rates are highly predictable and can be clearly communicated to drivers.



FLEET VEHICLES

Another category of new commercial EV load is vehicle fleets such as bus fleets and delivery vehicles. FedEx recently invested in 1000 new electric delivery vehicles,[4] while government and public transit authorities are increasingly seeking to substitute EVs for traditional gasoline or diesel vehicles.

Fleet vehicles may have greater ability to shift load and respond to price signals than DC fast charging stations, since fleets may have flexibility in their operations that enable them to schedule charging for particular times of day. For example, fleets may have the option to charge overnight, or to charge while parked over the course of the day. Fleet managers may also elect to purchase vehicles with longer ranges to avoid having to charge during more expensive peak hours. This flexibility tends to make TOU rates highly effective for fleets. Charging optimization software can help fleet managers take advantage of these rates and reduce the effort required to oversee charging.

Since fleet operators have more control over when their vehicles charge, some may be better able to effectively respond to critical peak pricing. If they have enough available charging infrastructure and flexibility in when the vehicles can be taken off the road for charging, fleet operators may be able to shift charging to off-peak periods when warned of a critical peak price in advance.

[4] See https://www.wsj.com/artiles/fedex-to-add-1-000-electric-vehicles-to-parcel-fleet-1542736194.

CASE STUDIES

Various jurisdictions have introduced electricity rates specifically for C&I EV customers. Some rate changes are temporary, or include temporary provisions, to encourage EV adoption over the next several years while there are still relatively few EVs on the road. Others instead try to make charges more reflective of the costs associated with EV charging by permanently modifying rate designs to increase the use of TOU energy rates and other time-varying features over demand charges. Such rate design modifications are an important mechanism for supporting the development of EV charging infrastructure and EV fleets.

Below we present specific examples of EV rates from different jurisdictions and discuss the merits and shortcomings of these approaches to the extent relevant.

DEMAND CHARGE DISCOUNTS

Demand charges are particularly burdensome to EV customers, particularly during the early years when EV charging results in high electrical demand but relatively low energy use. For example, empirical analysis by Rocky Mountain Institute has shown that demand charges can drive over 90 percent of the costs of operating public fast charging stations during summer months in California, making it extremely challenging to recoup costs while EV penetration and station utilization are still low.[5] To address this issue, numerous utilities are now providing temporary demand charge discounts for commercial EV customers, especially for DC fast charging stations.

For example, in New York, Con Edison's Business Incentive Rate offers rate discounts to public DC fast charging customers until 2025. [6] In Oregon, Pacific Power implemented a rate adjustment for DC fast chargers that temporarily reduces demand charges and increases on-peak energy charges. Within a decade, the demand charge will be phased back in.[7] While these temporary discounts may be appealing as EV adoption is still in its early stages, utilities should strongly consider focusing instead on more sustainable long-term solutions that provide proper price signals to EV charging customers.

Explicit discounts also raise questions of equity and access. For example, Tesla, which operates the largest fast charging network in the United States, was originally excluded from an order that adopted a "Consensus Proposal" developed by stakeholders in New York to address issues with demand charges on the grounds that the Tesla network is not "technologically accessible" to non-Tesla drivers. The Commission ruled that Tesla could receive the "per-plug" rebate if Tesla stations were made accessible to all EV drivers (i.e., included non-Tesla plugs), leading the automaker to file suit against the New York Public Service Commission.[8] If, rather than developing a "discount" on an existing C&I rate that was only made available to certain customers, Con Edison and the other parties had instead proposed a new, cost-based rate available to all C&I EV customers, this dispute might have been avoided and a more durable solution achieved.

XCEL ENERGY

In Colorado, Xcel Energy proposed a new rate structure for C&I EV charging in 2019. Xcel's standard C&I rate, Schedule SG, recovers most costs through demand charges. There are demand charges for summer and winter generation capacity and transmission as well as year-round demand charges for distribution.[9] In contrast, the new EV charging rate, Schedule S-EV, which is reflected in a settlement agreement pending final Commission approval, eliminates the generation and transmission demand charges and replaces them with time-varying energy charges. In addition to the new energy charges, S-EV contains a critical peak

[5] Garrett Fitzgerald and Chris Nelder, "EVgo Fleet and Tariff Analysis" (Rocky Mountain Institute, April 2017), https://www.rmi.org/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf.

[6] Consolidated Edison Company of New York, Inc., Tariff Book, Revision 5, Leaf 201, Rider J, issued February 7, 2019.

[7] Max St. Brown, "Staff Report Re: Schedule 45- Public DC Fast Charger Delivery Service Optional Transitional Rate," Docket No. ADV 485/Advice No. 16-020, May 8, 2017.

[8] New York Public Service Commission, Order Establishing Framework for Direct Current Fast Charging Infrastructure Program, February 7, 2019; Verified Article 78 Petition and Complaint, Tesla, Inc., vs New York State Public Service Commission, filed August 2, 2019.

[9] Public Service Company of Colorado, Electric Tariff Index, Sheet No. 43, issued January 1, 2017.

price of $1.50/kWh that is permitted to occur for a maximum of 60 hours each year.[10]

Xcel's proposed rate reduces costs for some EV charging customers by reducing demand charges. However, the critical peak price creates substantial uncertainty for customers with limited ability to shift load, such as DC fast charging stations. The remaining non-coincident distribution demand charge, at $5.63/kW, also continues to be a burden for low load factor EV charging customers. To improve this rate, any distribution costs that are caused by a local peak rather than by a single customer's peak demand should be recovered through a time-varying energy charge or a coincident peak demand charge that only applies during certain hours. The rate may work well for fleet customers with predictable duty-cycles and an ability to respond to critical peak price events. But because it largely fails to address the issues hampering the deployment of DC fast charging stations, Xcel has committed to proposing a new rate in 2021.[11]

PACIFIC GAS & ELECTRIC

Pacific Gas and Electric Company (PG&E), one of the nation's largest utilities, took a ground-up approach in designing new C&I EV rates for various use cases. The utility partnered with the Electric Power Research Institute to conduct customer and stakeholder outreach in advance that was used to inform the resulting rate design. The company recently received approval for the resulting rates that combine a subscription charge with a time-varying energy charge.[12] The subscription charge replaces fixed and demand charges with a per-kilowatt charge based on peak demand. Unlike conventional demand charges, the subscription charge requires a prospective commitment, in which the customer *subscribes* to a specific level of peak demand in advance. The final approved rate provides customers with a grace period of three billing cycles for monthly peak demand exceeding subscription levels. In addition, the rate uses TOU rates for energy costs with an on-peak to off-peak price ratio of approximately 2.5:1.

Of note, the Commission ruled that no distribution costs beyond marginal distribution costs should be recovered through the subscription charge, since the rate would apply to a new rate class without a full revenue allocation study and any revenue collected from the new class beyond the marginal cost to serve them would be an overcollection.[13] This had the effect of substantially reducing the subscription charge below the level originally proposed by PG&E (by around 40 percent), and means that customers on the commercial EV rate will only pay marginal costs until new rates go into effect in 2025 at the conclusion of the next General Rate Case.[14]

Although the primary rationale for maintaining rates at marginal costs was the absence of a revenue allocation study, an argument could also be made that marginal cost pricing is appropriate from the standpoint of encouraging greater EV adoption, which is akin to the rationale behind economic development rates. As long as rates for new load are set to recover marginal costs, existing customers will not see any increase in their rates. Meanwhile, the additional revenue from residential EV charging, where the vast majority of EV charging occurs, is likely to continue to result in net revenue in excess of associated costs.

The final approved commercial EV rate creates strong incentives to shift electricity consumption to off-peak hours without penalizing low load factor customers. While we note that the subscription format may present new challenges for customers, the reduction in subscription cost (and in the penalties for undersubscribing) and the opportunity for low-cost off-peak charging provide good incentive for transportation electrification for commercial fleets. These rate design modifications will mean substantial savings for C&I EV customers – especially for those with low load factors, for whom demand-charge weighted rate

[10] Recommended Decision, Proceeding No. 19AL-0290E. October 8, 2019.

[11] Unopposed Comprehensive Settlement Agreement, Proceeding No. 19AL-0290E.

[12] Decision Approving Application for Pacific Gas and Electric Company's Commercial Electric Vehicle Rates, D.19-10-055, in A.18-11-003. October 28, 2019.

[13] In order to allocate embedded costs, a revenue allocation study must be performed in which costs are allocated based on class billing determinants (peak demand, energy sales, number of customers, etc.). Such a study has not yet been performed for the new commercial EV customers in PG&E's territory. *See:* Decision Approving Application for Pacific Gas and Electric Company's Commercial Electric Vehicle Rates, D.19-10-055, in A.18-11-003. October 28, 2019.

[14] SDG&E has proposed to take a similar approach for its Electric Vehicle High-Power (EV-HP) Rate, initially collecting only marginal costs in its subscription charge and phasing embedded costs in over a period of ten years. While not yet approved, this signals a growing endorsement of marginal-cost based rate design for commercial EV rate reform.

designs can produce onerous bills. Customers on the new rate will save an estimated 30 percent to 50 percent or more on their current monthly bills and would pay roughly *half* the price they would have if they used gas or diesel.[15]

SOUTHERN CALIFORNIA EDISON

Southern California Edison (SCE) established an EV rate that temporarily eliminates demand charges for EV charging through 2023 and instead recovers costs through a TOU energy charge and a small fixed charge. By recovering all costs through energy charges that vary depending on the cost of providing electricity, SCE's new rate strongly incentivizes charging at low-cost hours for the grid. Demand charges will be phased back in starting in 2024 unless otherwise dictated by the Commission, at which point it is expected that many DC fast charging stations will have higher load factors and be able to spread demand charges over more total electricity sales. However, there may still be charging stations that have low utilization at that point both because EV adoption is still at an early stage and because stations will be needed in relatively remote places to allow for longer-distance trips. Indeed, certain stations may never have high load factors.[16] It is incumbent on SCE, other stakeholders, and state regulators and policymakers to formulate solutions, through rate design or other supportive policies (promoting storage that can assist in

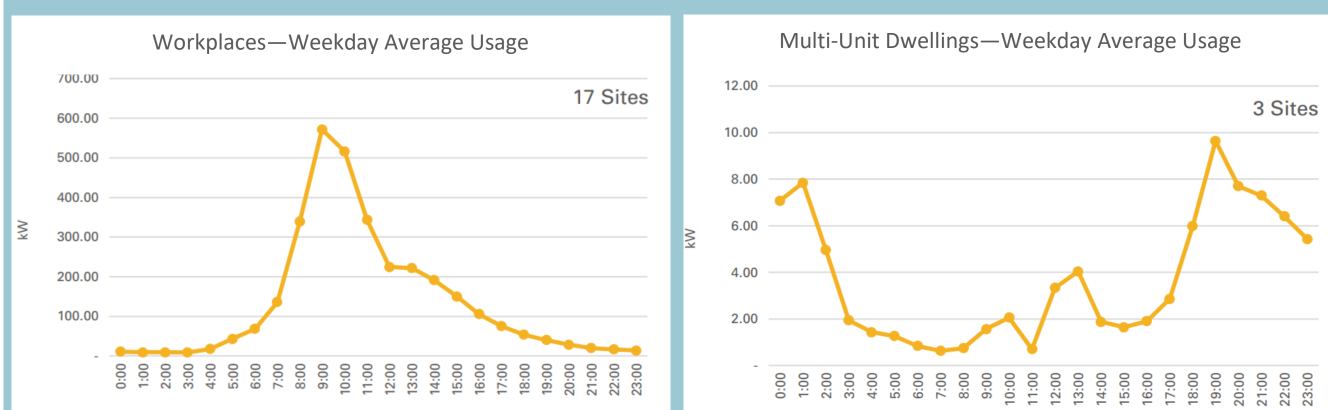
Time of Use

improving load factor, for example), that will enable investment in these necessary charging stations.

SCE has also grappled with how to ensure that efficient price signals are conveyed to the end user (i.e., the driver). Even the most efficient price signals lose their effectiveness if the driver does not see these signals. This often occurs when the customer-of-record who is billed for the electricity is different than the EV driver, such as at many workplace and public charging stations. In these situations, the driver may receive free charging, or be charged a fee based on the number of minutes the vehicle is plugged in, rather than based on the timing and quantity of electricity consumed.

In SCE's Charge Ready Program Pilot, site hosts were required to take service on TOU rates, but there was no requirement that those price signals be passed through to EV drivers. The charging profiles in the Charge Ready pilot program report, presented below in **Error! Reference source not found.**, show that the lack of time-varying price signals facing EV drivers resulted in those drivers charging immediately upon arrival at their destination with no correlation to grid conditions or time-of-use periods.[17]

Figure 1. Load Profiles from Charge Ready Pilot



15 Exhibit PGE-1, Pacific Gas and Electric Company Commercial Electric Vehicle Rate Proposal Prepared Testimony, November 5, 2018, p. 1-27.

16 SCE Schedule TOU-EV-7. July 26, 2019. Available at https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/general-service-&-industrial-rates/ELECTRIC_SCHEDULES_TOU-EV-7.pdf.

17 *See* SCE Charge Ready Pilot Program Report at 21-22 (indicating that charging in many segments was occurring primarily during late afternoon and evening hours).

This result is unfortunate, but entirely predictable; if given no reason to do otherwise, drivers will charge whenever they arrive at their destination. Thankfully, SCE has recognized this problem and taken steps to address it going forward. In its Charge Ready 2, full-scale program that is currently pending regulatory approval, SCE has committed to ensuring that the default arrangement will be that drivers see TOU price signals.

CONCLUSIONS

TOU RATES PROVIDE EFFICIENT AND EFFECTIVE PRICE SIGNALS

Jurisdictions are increasingly turning to TOU rates to provide simple but efficient price signals to EV drivers. These rates have been shown to be highly effective at encouraging EV customers to charge during off-peak hours, while maintaining simplicity and predictability. These attributes allow customers to schedule and optimize their charging with relative ease, unlike more volatile rate designs.

TRADITIONAL DEMAND CHARGES PRESENT AN UNNECESSARY BARRIER TO TRANSPORTATION ELECTRIFICATION

It is widely recognized that demand charges can undermine the economics of EVs for many customers. Non-coincident demand charges tend to be particularly harmful to a range of C&I EV customers, including fleets that charge mostly during off-peak hours and DC fast charging stations with low load factors. While customers may take steps to avoid coincident peak demand charges, non-coincident charges are much harder to mitigate. However, even coincident demand charges generally fail to provide accurate price signals. These charges fail to capture the duration of a customer's usage during peak hours, and thus the extent to which the customer is driving the need for grid investments on shared infrastructure.

For these reasons, TOU energy charges or critical peak pricing are generally preferable to coincident demand charges for recovering the costs of shared infrastructure, since energy charges better capture the duration of time that a customer is using that infrastructure. A time-varying energy rate charges a customer more for using the distribution system more extensively during peak hours, while a demand charge is assessed only based on the customer's monthly maximum usage.

Limited non-coincident demand charges may be appropriate for recovering distribution infrastructure costs that are sized to meet the maximum demand of a single customer. However, we caution that non-coincident demand charges are often set too high and recover costs that are not truly driven by individual customer peaks. Care should be taken that only costs for components that are sized to serve customer's individual peak should be recovered through noncoincident demand charges. In addition, if the customer already paid for a line extension through interconnection fees, the remaining customer-specific distribution costs to be recovered should be minimal.

CRITICAL PEAK PRICING AND DYNAMIC PRICING MAY BE APPROPRIATE FOR SOME CUSTOMERS

Critical peak pricing sends the strongest price signals during peak hours, but it also shifts large amounts of uncertainty onto customers. Certain types of EV customers, particularly public charging stations, may not be able to respond to these incentives and will suffer from this rate structure. For this reason, we recommend that critical peak pricing be provided as one option for C&I EV customers, but not the only option. This will allow customers to opt in if they believe that they will be able to adequately respond to the price signal and save money on their bill by reducing grid costs.

Dynamic pricing also provides strong signals to customers and vary hour by hour to reflect evolving supply and demand conditions – particularly those related to variable renewable generation. As with critical peak pricing, dynamic rates are most efficient when deployed to customers with the ability to respond to the signal. Customers most suited to dynamic rates are those with the flexibility, technology, and sophistication to automate their consumption behavior to minimize costs.

SETTING RATES TO RECOVER MARGINAL COSTS CAN HELP ATTRACT BENEFICIAL LOAD

EVs have enormous potential to reduce air pollution and lower electricity rates for all customers. Rate design can help accelerate the deployment of EVs to maximize these benefits. To accomplish this, it is essential that fueling with electricity be more cost effective than fueling with gasoline or diesel. Setting prices below embedded costs in the near term can help drive transportation electrification during the early years, leading to greater long-term benefits. As long as rates are set to recover at least the marginal costs of serving EV load, existing customers will see no increase in rates.

Setting rates below embedded costs also recognizes that EVs are a new load that did not drive historical grid investments. If EVs were to be charged for previously incurred fixed costs, EV adoption may be held back. As EV adoption grows and marginal costs become embedded costs, it may be appropriate to gradually include a larger portion of embedded costs in EV rates.

PRICE SIGNALS SHOULD BE CONVEYED TO THE END USER

Even the most efficient price signals lose their effectiveness if the end-user (driver) does not see these signals. To the extent that customers-of-record are not identical to end users, utilities and policymakers should aim to equip the former with the tools and guidance necessary to transmit price information on to EV drivers. Especially if the customers-of-record receive rebates or other forms of utility support to install EV charging infrastructure, the receipt of that customer-funded support should generally be made contingent upon terms of participation. Such terms could include making the pass-through of TOU price signals the default arrangement. They can ensure drivers realize the fuel cost savings that motivate EV purchases and are motivated to charge in a manner that does not strain, but supports the electric grid.

Image Sources:
Page 2: Traffic-Related Air Pollution. Photo by Alexander Popov on Unsplash.
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