BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	**)**
Application of Duke Energy Progress,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-5

Driving Transportation Electrification Forward in New York

Considerations for Effective Transportation Electrification Rate Design

Prepared for Natural Resources Defense Council

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AUTHORS

Melissa Whited
Avi Allison
Rachel Wilson

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

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EXECUTIVE SUMMARY

Electrifying the transportation sector will be necessary to achieve large-scale greenhouse gas reductions. Converting internal combustion engine (ICE) vehicles to electric vehicles (EVs) could also provide substantial net benefits to society through substantially reducing transportation fuel costs while simultaneously reducing electricity rates through better utilization of existing infrastructure. These benefits are far from certain, however. Achieving these benefits hinges on two key factors:

1) Charging EVs in a manner that minimizes costs to the grid, and
2) Widespread adoption of EVs.

Electric utilities are in a unique position to influence both of these factors through electric rate design.

Managing peak demand is a key challenge for electric utilities. As the penetration of EVs increases, charging EVs during times of peak demand could exacerbate grid constraints, require the construction of new power plants or transmission and distribution infrastructure, and increase costs for customers.[1] In addition, certain electric rate structures can pose financial barriers to potential EV customers and owners of public EV charging stations. These barriers could reduce demand for EVs and slow the transition to the cleaner transportation system necessary to meet state goals.

To avoid these pitfalls, electric utilities should provide EV customers with clear electricity price signals to encourage charging off-peak. Further, well-designed electricity pricing can help encourage the adoption of EVs and support the financial viability of public EV charging stations. This report examines best practices in EV rate design and provides comments on New York utilities' EV rate design proposals submitted in Docket 18-E-0206.

Rate Design Options

Standard, time-invariant electricity rates do little to encourage EV adoption or optimal charging times. In fact, these rates may even directly discourage efficient charging practices, since customers are apt to charge when it is most convenient to them, rather than when it is most beneficial to the grid. In contrast, time-varying rates convey price signals that better reflect the cost of producing and delivering energy during different hours. Time-varying rates include time-of-use (TOU) rates, critical peak pricing, peak time rebates, and dynamic hourly pricing. In addition, some utility rates include a demand charge, which is typically based on a customer's maximum consumption during a month.

Each of the above rates has advantages and drawbacks. However, TOU rates are the most popular form of time-varying rate, both for EV customers and non-EV customers. TOU rates are popular for several reasons:

[1] Current penetrations of EVs are unlikely to have a material impact on the grid, but as adoption increases, more attention to load management is warranted.

- **Effectiveness:** TOU rates have proven to be highly effective in shifting EV load. Both whole-house and EV-only TOU rates have been implemented at all three of California's large investor-owned utilities (IOU) and have been extremely successful in motivating customers to avoid charging on-peak. At Pacific Gas & Electric, 93 percent of charging on the EV-only rate occurs during off-peak hours, while at Southern California Edison, 88 percent of charging is off-peak.[2]

- **Simplicity:** TOU rates provide an easy-to-understand price signal that reflects general trends in utility costs, without requiring customers to monitor hourly energy prices. TOU rates are particularly well suited to "set it and forget it" technologies, such as the timers on many EV chargers.

- **Efficiency:** TOU rates can be designed by layering different types of utility costs (generation, transmission, and distribution) to reflect the temporal variability of all three.

Section 3.2 below provides more detail regarding the methods that can be used for designing TOU rates in a manner consistent with the time-varying nature of generation, transmission, and distribution costs.

Demand charges, which are typically based on a customer's maximum usage during a month, are generally not well suited to providing price signals that will support EV adoption. In fact, demand charges can work to discourage critical EV charging infrastructure deployment while the EV market is still in early development. A demand charge that applies during any hour of the day effectively becomes a fixed charge that cannot be avoided by scheduling EV charging for off-peak periods. For public charging stations, demand charges can undermine the financial viability of the station. While the maximum electricity demand at these stations is very high, energy use tends to be low due to the limited number of EVs on the road today. This means that demand charges tend to dominate the electricity bills for these stations, and these costs are very difficult to recover from the low number of EV customers.

To address this problem, some utilities have temporarily reduced or eliminated demand charges for public charging infrastructure, opting instead to price electricity using TOU rates. Cross-subsidization due to such rates is unlikely as long as electricity is priced at or above the utility's marginal cost of service,[3] since EV stations are supporting incremental load growth, rather than representing existing load on the system.[4]

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[2] Synapse Analysis of Joint Utilities Load Research Report, December 2017.

[3] Any required distribution upgrades directly related to the charging station should also be recovered from the charging station owner in order to avoid shifting these costs on to other customers.

[4] Existing tariffs are designed to recover embedded costs from existing load, which enables incremental load to be priced at marginal cost, at least during the early years of EV adoption.

Metering Technologies for EV-Only Rates

Customers may prefer an EV-only TOU rate to a whole-house rate because it is much easier for customers to monitor and control the timing of EV charging than the use of other appliances in the home. However, EV-only rates require a separate revenue-grade meter or the use of submetering technology to record electricity use that is specifically attributable to EV charging.

Although a second meter makes it easy to apply TOU rates only to EV charging, the additional meter and installation charges involved can be formidable. The installation can cost thousands of dollars up front for customers, eliminating virtually all of the fuel cost savings associated with the EV-only rate. Some utilities also assess a second customer charge for the second meter. These high costs have contributed to very low customer enrollment in EV-only TOU rates that require a second meter.

Several different submetering technologies are available. These include:

- Stand-alone submeters such as the WattBox™ from eMotorWerks, with a cost of approximately $250. In some pilot programs, connectivity and data transfer issues have been a problem. In addition, installation typically requires an electrician and will incur an additional cost.

- Submeters integrated with the EV supply equipment (EVSE). At-home EVSE are generally Level 2 charging with costs typically between $500 to $900. The installation of these EVSE requires an electrician at additional cost. EVSE-integrated submeters have been used by some municipal utilities, is being piloted at a large scale in California, and will soon be piloted in Minnesota.

- Mobile (in-car) submeters such as the FleetCarma C2 device. This device is "plug-and-play," allowing the EV owner to simply plug it into a port under the dash of the vehicle. The device then collects vehicle charging and driving data and sends the data securely to FleetCarma servers over the cellular network. However, the annual costs to the utility associated with the use of this device at present appear quite high.
- On-board metering (integrated into the vehicle itself) may be an option for off-peak charging rebate programs and could potentially be extended to other rate structures in the future. A key barrier to extending on-board metering to other rate structures is the requirement for revenue grade metering and the implications for billing responsibility.

Each metering option has certain advantages and drawbacks. While a second utility meter is a straightforward option, the costs of installation can be prohibitively high, and customer charges associated with a second meter can deter customers. Submetering is promising, particularly if installation costs can be reduced further and data transfer issues can be fully resolved.

Maximizing Customer Enrollment

To achieve the benefits promised by time-varying rates, customer enrollment levels must be maximized. Simply designing a rate well is not sufficient to ensuring its success. Due to customer inertia, low levels of customer enrollment are common when customers are required to actively opt-in to the rate. Currently enrollment levels in most New York utilities' existing TOU rates are below 0.5 percent.

Electric utilities can achieve high levels of customer enrollment through defaulting customers onto a rate (through an opt-out design). Where defaulting customers onto a time-varying rate is not feasible, utilities must actively encourage enrollment through a combination of education, outreach, and incentives. In addition, it is important to ensure that utility incentives, auto dealership incentives, and customer incentives are all aligned. Activities to maximize EV customer enrollment in EV rates may include:

- **Website Tools:** Rate comparison calculators, such as Southern California Edison's Electric Vehicle Rate Assistant Tool, provide an easy way for customers to compare their potential cost savings over several different rate options.

- **Dealership Education and Incentives:** Auto sales representatives often have little to no understanding of the rates available to EV drivers, or the potential savings these could provide to customers. In California, a collaboration of organizations developed and conducts a dealership training curriculum, and a $250 dealership incentive is provided for each EV purchase in which the customer also signs up for an EV rate.[5]

- **Direct Outreach to EV Customers:** It can be difficult for a utility to identify which of its customers have purchased an EV. To identify customers, utilities may be able to work with state agencies to access Department of Motor Vehicle registration records and directly contact EV drivers. Some utilities also offer gift cards or other rewards to customers. For example, Salt River Project in Arizona provides EV customers with a $50 gift card simply for signing up for the utility's EV mailing list. Establishing these points of contact can be an important first step to educating and enrolling customers in an EV rate.

- **Price Guarantees:** Price guarantees may be offered for the first six months or year after a customer signs up for a new rate. These guarantees ensure that the customer will not pay more on the time-varying rate than they would on a standard rate, thereby reducing the customer's risk of signing up for a rate structure that is new to them.

Assessment of New York Utility EV Rate Proposals

The New York electric IOUs recently submitted proposals for residential EV tariffs to comply with New York Public Service Law Section 66-o(2). The overall structure of these proposed rates is sound, but there are several key areas where the proposals could be strengthened. In particular, many of the

[5] The monetary incentive was recently approved for SDG&E. *See:* California Public Utilities Commission. Decision on the Transportation Electrification Priority Review Projects. Decision 18-01-024. January 11, 2018, page 39.

proposals fail to deliver the fuel cost savings needed to encourage customers to enroll in the rate and to motivate EV purchase decisions.

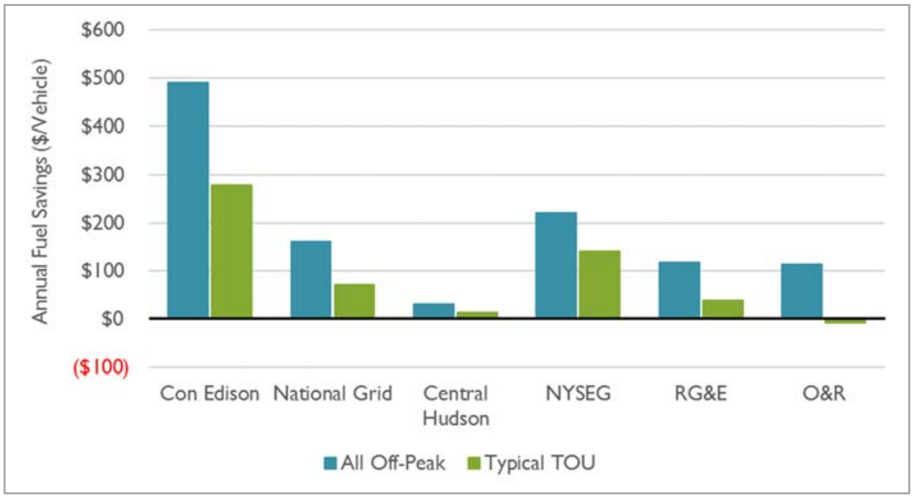
- **Metering:** None of the New York IOUs have proposed a submetering option using an EVSE for their EV rates, nor have they explained why submetering was not proposed. Instead, the IOUs that offer an EV-only rate would require a second traditional utility meter, with the exception of Consolidated Edison Company of New York's (Con Edison) ongoing SmartCharge NY program. The high cost of installing a second meter could dampen enrollment levels in EV-only TOU rates.

- **Rate Structure and Price Guarantee:** Each of the proposed residential EV tariffs use a TOU rate structure and include a one-year price guarantee that ensures that customers will not pay more on a whole-house TOU rate than they would have if they had remained on their original rate. These are very positive design decisions that will help to attract customers to the rate.

- **Fuel Cost Savings under Whole-House TOU Rate:** To achieve New York's policy goals, the ability for EV drivers to achieve fuel savings on the rate should be a central component of the rate design. Fuel cost savings are important for encouraging customers to adopt the rate and to motivate EV adoption. Synapse evaluated two metrics for assessing a customer's fuel cost savings: (1) savings on the TOU rate relative to the standard rate, and (2) savings from fueling the EV on the TOU rate relative to the cost of fueling an ICE vehicle. In both cases, we assumed a battery electric vehicle (BEV) with a range of 100 miles, similar to a Nissan Leaf or a BMW i3.

  Our analysis indicates that the fuel cost savings of the proposed TOU rates relative to standard rates vary substantially across utilities, as shown in the figure below. The figure shows fuel cost savings under two different scenarios: one in which 100 percent of the customer's EV charging occurs off-peak; and the other assuming more typical customer behavior in which most, but not all, charging occurs off-peak.

Figure ES-1. Whole-house TOU rate annual fuel cost savings relative to standard rate

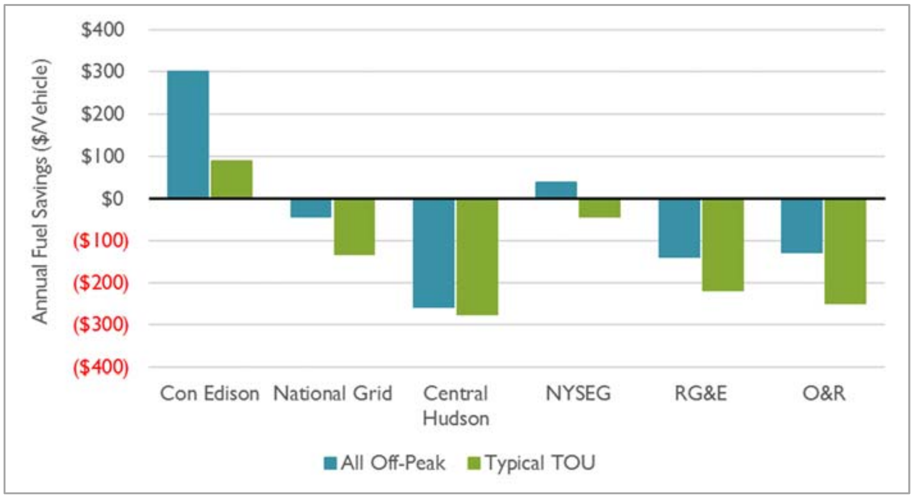


Source: Synapse Energy Economics analysis.

The whole-house rates proposed by Con Edison and New York State Electric and Gas (NYSEG) offer the greatest potential savings, with Con Edison customers experiencing annual fuel cost savings of approximately $500. In contrast, Central Hudson's rate (which has a low price differential between on-peak and off-peak), average annual savings amount to less than $50 even if all charging takes place during off-peak hours.

- **Fuel Cost Savings under EV-Only TOU Rate:** Con Edison, Orange and Rockland Utilities (O&R), NYSEG, and Rochester Gas and Electric (RG&E) include the option for customers to charge EVs under a separately metered TOU rate, rather than under the whole-house TOU rate. However, separately metered customers would likely have to pay an extra customer charge. The figure below shows that customers receive lower fuel cost savings from switching to the utilities' EV-only TOU rate, as the additional customer charge offsets the savings associated with a lower off-peak energy charge. In fact, we estimate that typical separately metered EV customers would incur *increased* fuel costs at every utility other than Con Edison. Customers of O&R could incur additional EV fuel costs of $250 by switching to the separate-meter TOU rate.

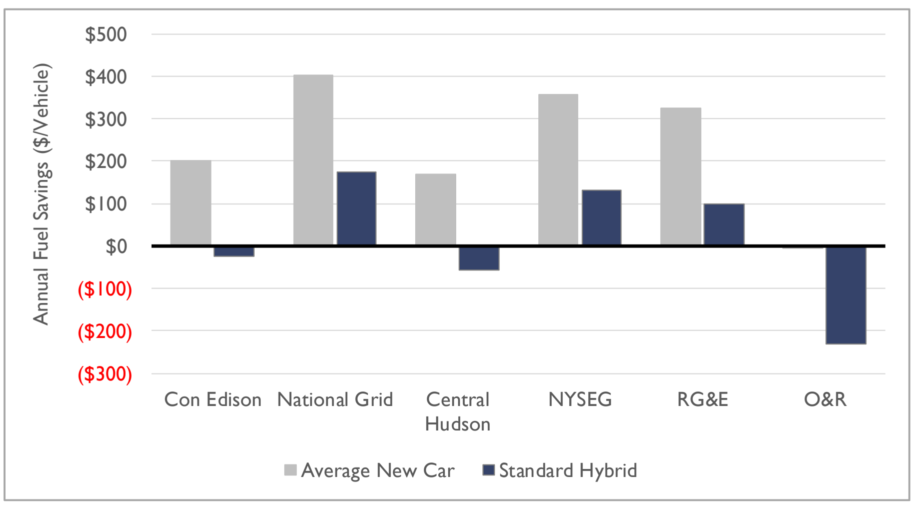
Figure ES-2. EV-only TOU rate annual fuel cost savings relative to standard rate



Source: Synapse Energy Economics analysis.

- **Fuel Cost Savings Relative to Gasoline-Powered Vehicles:** The fuel cost savings provided by EVs on the proposed TOU rates relative to ICEs also vary greatly depending on the utility and the ICE in question. The figure below presents our calculated fuel cost savings for each utility for a typical 100-mile BEV on a whole-house TOU rate relative to two alternative types of ICEs: a typical new car with an efficiency of 38 mpg, and a standard hybrid with an efficiency of 55 mpg.

Figure ES-3. Annual fuel cost savings on whole-house TOU rate relative to alternative ICE types



Source: Synapse Energy Economics analysis.

In nearly all utility service territories, the whole-house TOU rate would generate positive fuel cost savings relative to a typical new gasoline-powered vehicle. However, when compared to a standard hybrid vehicle, such as a Toyota Prius, EV fuel savings largely disappear. This comparison is important, because customers considering purchasing an

EV are likely to compare these vehicles to high-efficiency ICE options, such as standard hybrids. At three of the six IOUs, an EV customer would likely have higher fuel costs relative to a hybrid vehicle—more than $200 higher in O&R's territory.

One of the primary reasons that O&R's EV-only rate option offers the lowest fuel cost savings relative to both a standard residential rate and an ICE is that it has a relatively high customer charge of $12.00 per month. This charge is nearly three times greater than any other utility. This additional customer charge could potentially be avoided if the utility employed submetering rather than a second meter. However, it is not clear that a second customer charge is even fully justified for a second meter, given that many customer-related costs (such as the cost of the final line transformer and service drop) would not change upon the installation of a second meter on the customer's premises.

- **Ratio Between Peak and Off-Peak Rates.** Higher ratios between on-peak and off-peak price help to encourage EV customers to charge during off-peak hours and better enable customers to achieve fuel cost savings. Con Edison and O&R's proposed on-peak to off-peak price ratios are greater than 14:1 in the summer months and greater than 5:1 in the winter months. In contrast, Central Hudson's rate has a ratio of only 1.2:1 throughout the year.

  The IOUs also offer standard offer supply service TOU rates for customers who do not purchase electricity supply from a retail supplier. Con Edison's TOU standard offer service rates vary dramatically between peak summer hours and other times of the year, whereas the TOU standard offer service of NYSEG and RG&E do not exhibit marked differences between peak and off-peak hours. The reason for this differential could lie in zonal wholesale market prices, but it is worth reviewing the price differentials to ensure that the standard offer service prices contribute to an efficient overall TOU price.

- **Customer Enrollment in TOU Rates.** To date, enrollment in the New York IOUs' TOU rates has been very low, with most enrollment levels below 0.5 percent of residential customers. Although not required by the law, it is clear that to encourage EV customers to enroll in the utilities' new TOU rates, the IOUs must do more than simply establish the rate. The utilities must actively encourage enrollment through a combination of education, outreach, and incentives for both customers and auto dealerships. In addition, utility incentives should also be aligned with enrolling customers in EV rates. This could take the form of Earnings Adjustment Mechanisms that establish targets not only for customer adoption of EVs, but also for enrollment in an EV rate.

In conclusion, the New York utilities have a unique opportunity to influence EV adoption and steer EV charging practices to benefit the grid and society. The utilities' recent proposals represent a step in the right direction but require additional work to unlock their full potential. Specifically, we offer six recommendations:

1) Utilities with low price differentials between on-peak and off-peak rates increase the price ratio to motivate off-peak charging and enable greater fuel savings;
2) Ensure that a customer who charges mostly off-peak achieves fuel savings relative to a customer who remains on a standard rate and charges only on-peak;
3) Reduce or eliminate the customer charge for second meters;
4) Explore submetering as a means to lower the cost for EV-only rates;
5) Evaluate whether the proposed rate will provide sufficient fuel savings to encourage customers to adopt EVs over high-efficiency ICE vehicles; and
6) Endeavor to maximize customer enrollment through education, outreach, and incentives.

Finally, we recommend that these actions on residential rate design be complemented by an analysis of commercial and industrial rates to determine whether modifications are warranted to support EV charging stations, fleet electrification, and workplace charging.

1. INTRODUCTION

New York State will need to electrify its transportation sector to achieve large-scale greenhouse gas reductions.[6] This electrification could also substantially reduce transportation fuel costs, while simultaneously putting downward pressure on electricity rates through better utilization of existing infrastructure. In short, converting internal combustion engine (ICE) vehicles to electric vehicles (EVs) could provide substantial net benefits to society.[7] However, the extent to which those potential benefits are achieved hinges upon appropriate utility rate design.

Utility rate design is a key motivator for influencing whether customers charge EVs in a manner compatible with grid conditions, as well as the extent to which customers save money when refueling. Rapid adoption of EVs will be needed to meet energy policy goals, and studies reveal that saving money relative to an ICE is one of the most important motivators of EV purchase decisions.[8] Thus, the viability of an essential pathway to mitigate climate change and reduce America's exposure to the volatility of the global oil market depends upon appropriate rate design and on the decisions made by state utility regulators.

In New York, transportation accounts for roughly 34 percent of greenhouse gas emissions, whereas the state's electric power sector comprises less than 20 percent of emissions.[9] Addressing transportation emissions will be critical for achieving Governor Andrew Cuomo's target of reducing economy-wide

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[6] *See:* Daniel Steinberg et al., "Electrification & Decarbonization: Exploring U.S. Energy Use and Greenhouse Gas Emissions in Scenarios with Widespread Electrification and Power Sector Decarbonization" (NREL, July 2017), https://www.nrel.gov/docs/fy17osti/68214.pdf; J.H. Williams et al., "Pathways to Deep Decarbonization in the United States" (The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations, 2014); International Energy Agency, "Transport, Energy, and CO2: Moving Toward Sustainability" (Paris: IEA/OECD, 2009), https://www.iea.org/publications/freepublications/publication/transport2009.pdf; National Research Council, "Transitions to Alternative Vehicles and Fuels" (Washington, DC, 2013), https://www.nap.edu/catalog/18264/transitions-to-alternative-vehicles-and-fuels.

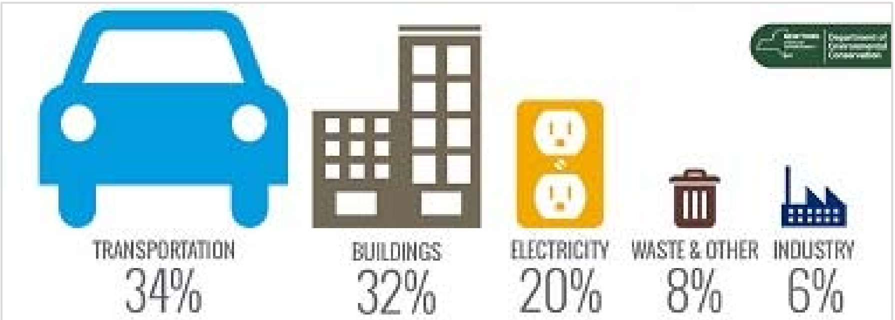
[7] We use the term "electric vehicles" to refer to both plug-in hybrid electric vehicles and battery electric vehicles.

[8] For example, a survey of nearly 20,000 EV owners in California found that fuel cost savings are the number one motivator for an EV purchase. In addition, NREL's annual surveys for the years 2015–2017 show that fuel cost savings consistently ranks as either the first or second most important reason for considering EVs. *See:* Center for Sustainable Energy (2016). California Air Resources Board Clean Vehicle Rebate Project, EV Consumer Survey Dataset: http://cleanvehiclerebate.org/eng/survey-dashboard/ev. *and* Mark Singer, "The Barriers to Acceptance of Plug-in Electric Vehicles: 2017 Update" (NREL, November 2017), https://www.nrel.gov/docs/fy18osti/70371.pdf.

[9] New York Department of Environmental Conservation, Mitigation of Climate Change: https://www.dec.ny.gov/energy/99223.html

greenhouse gas emissions by 40 percent by 2030 and 80 percent by 2050,[10] and for complying with Zero Emission Vehicle (ZEV) regulations that will require approximately 800,000 EVs in New York by 2025.[11]

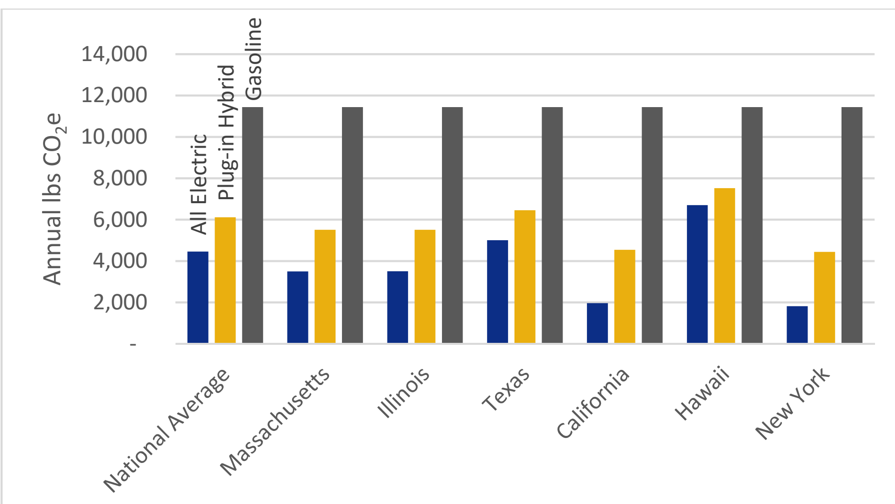
Figure 1. Greenhouse gas emissions by sector in New York



Source: New York Department of Environmental Conservation.

EVs provide a tremendous opportunity to enable New York to meet its greenhouse gas reduction targets and save money at the same time. On average, battery electric vehicles in the United States produce approximately one-third of the greenhouse gas emissions as ICEs. In New York, EVs are even cleaner—battery electric vehicles produce only 16 percent of the emissions of ICE vehicles (see Figure 2).[12]

Figure 2. Emissions from EVs and gasoline powered vehicles



Source: U.S. Department of Energy Alternative Fuels Data Center.

[10] New York's State Energy Plan established emission reduction targets of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. https://energyplan.ny.gov/.

[11] New York State is one of nine states that have adopted California's ZEV standards. These are incorporated by reference in 6 NYCRR Part 218, specifically Subpart 218-4.1 ZEV Percentages. These standards require automakers to produce a certain percentage of zero emission vehicles to improve air quality and combat climate change.

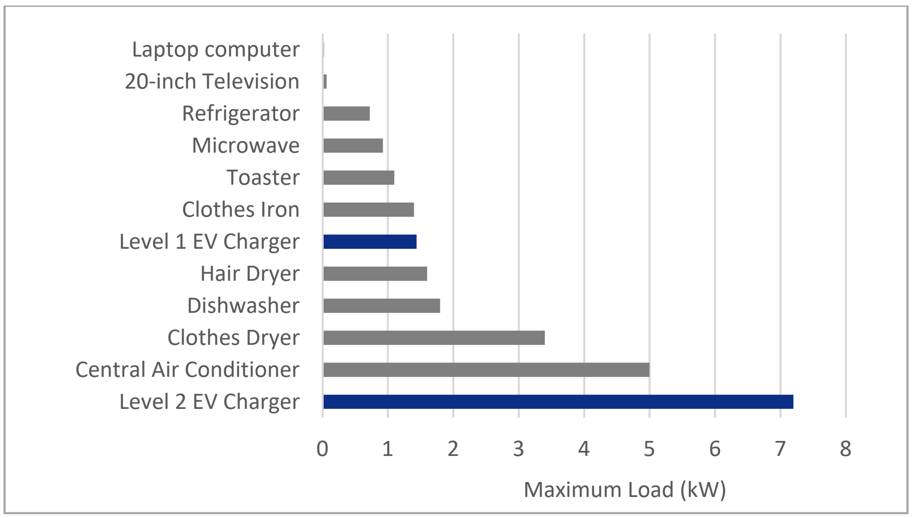
[12] U.S. Department of Energy Alternative Fuels Data Center. 2015. "Emissions from Hybrid and Plug-In Electric Vehicles." Available at: www.afdc.energy.gov/vehicles/electric_emissions.php.

By utilizing existing electricity infrastructure more efficiently, EVs can help lower electricity costs. For example, EVs can help to absorb excess energy from renewables when that energy is plentiful but demand is low, such as during the overnight hours. And by increasing the volume of electricity sold, EVs allow the fixed costs of the grid to be spread over more kilowatt-hours, thereby reducing electricity rates for all customers—regardless of whether the customer drives an EV. As technology evolves, EVs may increasingly provide services back to the grid and operate as "virtual power plants," helping to integrate renewable resources and enhance reliability.[13]

Achieving these benefits depends on (1) charging EVs in a manner that minimizes costs to the grid, and (2) widespread adoption of EVs. This is where electric utility rate design plays a critical role.

EVs are large consumers of electricity. Further, their instantaneous power draw can be significantly higher than any other typical household appliance, as shown in the figure below. In fact, an EV can easily double a household's peak demand when charged with a Level 2 charger.[14]

Figure 3. EV charging load relative to household appliances



Managing peak demand is a key challenge for electric utilities. As the penetration of EVs increases, charging EVs during times of peak demand could exacerbate grid constraints, require the construction of new power plants or transmission and distribution infrastructure, and increase costs for customers.[15]

Maximizing the benefits of transportation electrification also requires that barriers to EV adoption be removed. Certain electric rate structures can pose financial barriers to potential EV customers and

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[13] In the simplest case, EVs can operate as load reducers by temporarily deferring charging when the grid is stressed. But since EVs are essentially mobile batteries, their batteries can be tapped to provide more sophisticated services as well, such as frequency response and other ancillary services historically provided only by large power plants.

[14] A Level 1 charger uses a standard 120-volt outlet and provides approximately 4.5 miles per hour of charging. A Level 2 charger uses a 240-volt outlet and provides approximately 20 miles per hour of charging. DC fast chargers are another, much more expensive option, and they deliver power at 200–600 V_{DC} to provide approximately 240 miles per hour of charging.

[15] Current penetrations of EVs are unlikely to have a material impact on the grid. But as adoption increases, more attention to load management is warranted.

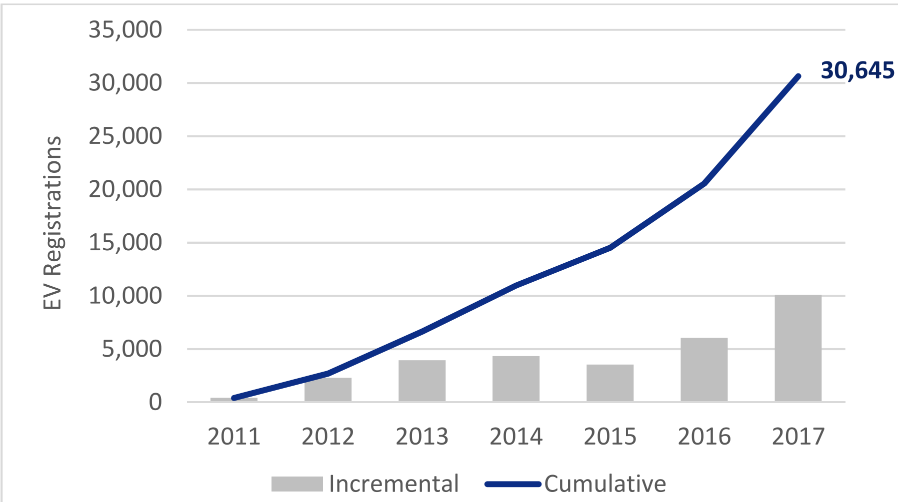
owners of public EV charging stations, thereby reducing demand for EVs and slowing the transition to the cleaner transportation system necessary to meet state goals.

To avoid these pitfalls, electric utilities should provide EV customers with clear electricity price signals to encourage charging off-peak. Further, electricity prices can be used to help encourage the adoption of EVs and support the financial viability of EV charging stations. This report examines best practices in electric vehicle rate design and comments on New York utilities' EV rate design proposals submitted in Docket 18-E-0206.

2. THE CASE FOR EFFECTIVE RATE DESIGN

Electric vehicle adoption in New York is rising rapidly: new EV registrations doubled from 2016 to 2017, as shown in Figure 4. Currently, New York is second only to California in the number of EVs in the United States.

Figure 4. EV growth in New York



Source: Auto Alliance.

At current levels of penetration, EVs could potentially add 215 megawatts (MW) of demand to New York's system if they all charged at the same time using a Level 2 charger. This is nearly equivalent to the total demand reduction expected from current energy efficiency programs.[16] Fortunately, this need not be the case. Because the electricity used to charge an EV's battery is often not immediately used to propel the vehicle, there is generally some flexibility regarding the timing of EV charging. Most drivers do not care when their EVs get charged, as long as the vehicles are ready to drive when needed. This inherent flexibility sets EVs apart from most major residential electricity end-uses (e.g., air conditioning) and opens up the possibility of encouraging efficient charging without inconveniencing consumers.

Given the rapid pace of EV adoption and the potentially large positive or negative impacts that EVs could have on the grid, it is critical that New York set in place a framework that will enable it to integrate EVs into the grid in a low-cost manner and avoid negative grid impacts. Electric utilities can play a prominent role in this regard, as they can provide price signals to customers to encourage EV owners to charge in a manner that is consistent with grid conditions.

[16] NYISO Power Trends, 2017.

Effective EV price signals can:

1) Encourage customer adoption of EVs by maximizing fuel cost savings relative to gasoline or diesel;

2) Lower electricity rates for all utility customers through more efficient grid utilization;

3) Avoid unnecessary grid upgrades by encouraging customers to shift charging to off-peak hours; and

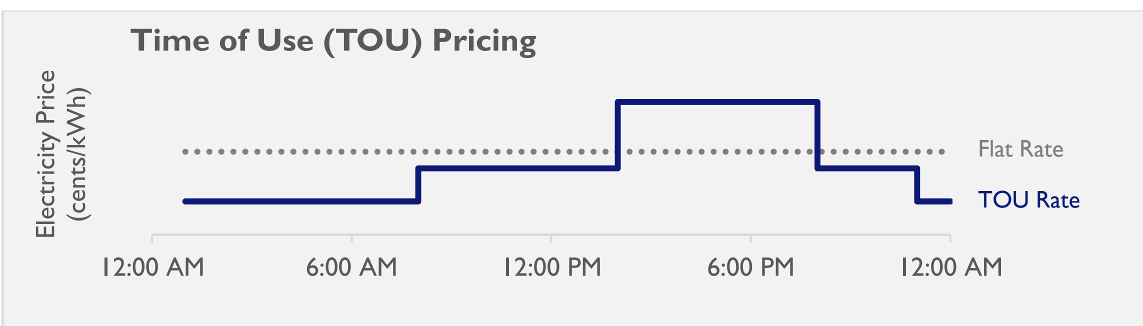
4) Reduce emissions by better aligning charging with renewable energy production.

The following sections discuss effective rate design options.

2.1. Rate Design Options

Standard, time-invariant electricity rates do little to encourage EV adoption or optimal charging times. In fact, these rates may even directly discourage efficient charging practices. Customers are apt to charge when it is most convenient to them, rather than when it is most beneficial to the grid. In contrast, time-varying rates convey price signals that better reflect the cost of producing and delivering energy during different hours. The most common forms of time-varying energy rates are described below, along with a stylized depiction of how each rate could be implemented.

- *Time-of-Use (TOU) Rates:* TOU rates consist of two or more pricing tiers, based on pre-set time periods. Electricity is priced higher during hours when the peak is more likely to occur, and lower during hours that are generally off-peak. An advantage of this type of rate structure is that it has low financial risks to customers, because the pricing is known ahead of time and customers choose whether to curtail their electricity use during on-peak times.

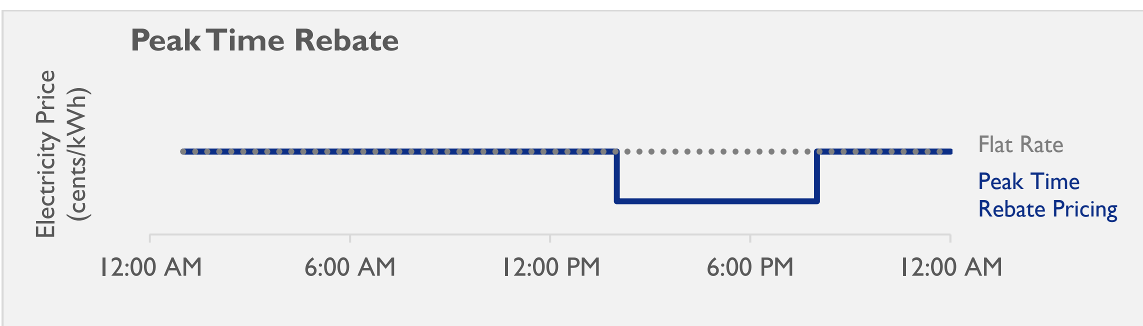


- *Critical Peak Pricing (CPP):* This rate structure is often used in conjunction with TOU rates but can be used with an otherwise flat rate structure as well. Critical peak pricing implements a very high price tier that is only triggered for very specific events, such as system reliability or peak electricity market prices.[17] The timing of the events is

[17] Hledik, R. et al., 2016.

generally not known until a day in advance, and the events typically last for only 2–6 hours.

- *Peak Time Rebates (PTR)*: A peak time rebate program is similar to critical peak pricing, except that customers earn a financial reward for reducing energy relative to a baseline, instead of being subject to a higher rate. As with critical peak pricing, the number of event days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.[18] While PTR programs tend to be widely accepted by customers, they have two drawbacks relative to critical peak pricing:
    - Baseline usage can be difficult to determine with accuracy. For example, a customer may earn a reward simply because the customer was out of town on the day of the event rather than because the customer actively reduced their electricity consumption in response to the event.
    - Peak time rebates tend to result in lower reductions than critical peak pricing. Customers generally respond more strongly when they are faced with paying more for consumption during peak hours than when they are offered a reward for lowering consumption.



- *Real-Time Pricing and Hourly Pricing:* These rates charge customers for electricity based on the wholesale market price rather than a pre-set rate schedule.[19] Rates fluctuate hourly or in 15-minute increments, reflecting changes in the wholesale price of

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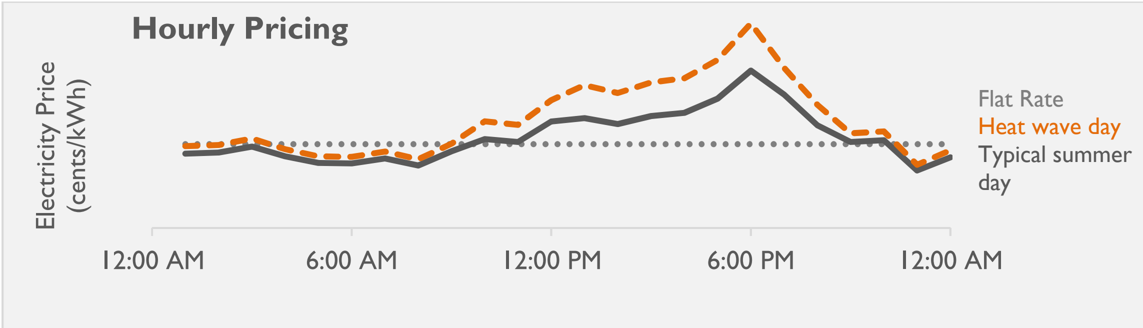
[18] United States of America. Federal Energy Regulatory Commission. *Assessment of Demand Response and Advanced Metering.* Washington D.C.: United States, 2010.

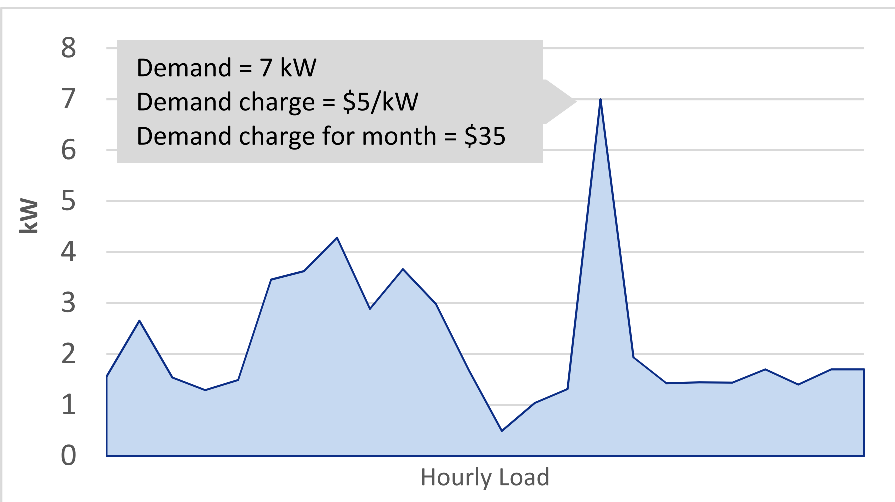
[19] *Id*.

electricity. Customers are typically notified of prices on a day-ahead or hour-ahead basis.



In addition to time-varying energy rates, some utility rates include a demand charge, particularly for large commercial and industrial customers. Instead of assessing a charge based on when and how much energy is consumed (measured in kWh), demand charges are applied to a customer's maximum consumption (measured in kW) during a month.[20] Demand charges can be designed to be time-limited (that, is they only apply during certain peak hours of the day), or they can apply during any hour. Figure 5 illustrates how a demand charge functions.

Figure 5. Hypothetical demand charge example



2.2. Considerations for Rate Design Selection

Overarching Considerations

Each of the above rates has advantages and drawbacks. However, TOU rates are the most popular form of time-varying rate, both for EV customers and non-EV customers. These rates have been offered by

[20] In some cases, demand charges are applied to some measure of a customer's maximum consumption over the course of a year.

utilities for decades and are gaining popularity now that advanced meters are reducing the costs associated with implementation. Results from a survey conducted by the Smart Energy Power Alliance (SEPA) indicate that at least 45 utilities across the country have TOU rates targeted to EVs.[21]

TOU rates are popular for several reasons:

- **Effectiveness:** TOU rates have been shown to be highly effective in shifting EV load.
- **Simplicity:** TOU rates provide an easy-to-understand price signal that reflects general trends in utility costs, without requiring customers to monitor hourly energy prices. TOU rates are particularly well suited to "set it and forget it" technologies, such as the timers on many EV chargers.
- **Efficiency:** TOU rates can be designed by layering different types of utility costs (generation, transmission, and distribution) to reflect the temporal variability of all three.

In contrast, critical peak pricing and peak time rebates only target a few peak hours per year. While such an approach may work well for avoiding additional generation capacity costs, it does not avoid daily higher-cost energy hours. In addition, such rates typically do not reflect the wider range of local distribution peak hours. Another consideration is that the specific hours for critical event days are generally called only a day in advance, making critical peak pricing and peak time rebates less compatible with "set it and forget it" technologies.

Hourly dynamic pricing is an efficient alternative to TOU pricing but is more complex and shifts more risk to customers. Where dynamic pricing is offered, enrollment tends to be low.[22] Further, dynamic pricing may be too variable for public charging stations. In California, the Public Utilities Commission rejected San Diego Gas & Electric's proposed dynamic rate for public charging infrastructure. The Commission wrote, "Dynamic rates are complicated, highly variable, and do not provide enough predictability for drivers that may not be participating in a specific utility program."[23] Instead, the Commission directed the utility to design a TOU rate that provides more predictability for drivers.

Demand charges are even less well-suited to providing price signals that will support EV adoption. In fact, demand charges can work to discourage critical EV charging infrastructure deployment while the EV market is still in early development. Demand charges that apply during any hour of the day effectively become a fixed charge that cannot be avoided by scheduling EV charging for off-peak periods. In the case of workplace and public DC fast charging (DCFC) stations, demand charges can pose

[21] Erika Myers, Medha Surampudy, and Anshul Saxena, "Utilities and Electric Vehicles: Evolving to Unlock Grid Value" (Smart Electric Power Alliance, March 2018), 24.

[22] For example, only about 17,500 customers out of 3 million have enrolled in Commonwealth Edison's dynamic pricing program. Dick Munson, "Data Reveals Real-Time Electricity Pricing Would Help Nearly All ComEd Customers Save Money," *EDF Energy Exchange* (blog), November 14, 2017, http://blogs.edf.org/energyexchange/2017/11/14/data-reveals-real-time-electricity-pricing-would-help-nearly-all-comed-customers-save-money/.

[23] California Public Utilities Commission, Decision on the Transportation Electrification Priority Review Projects, Decision 18-01-024, Application 17-01-020 et al, January 11, 2018, page 42.

a significant financial disincentive because of the potential to raise customers' bills. Further, demand charges for public charging stations are difficult for the site host to pass on to EV drivers, since the charges billed to the site host are not proportional to utilization by drivers. We discuss this in greater detail in the following section.

Considerations for Public Charging Rates

Rate designs that support, rather than hinder, the development of public charging stations are important for encouraging EV adoption. DCFC stations generally provide power between 50 kW and 350 kW, which enables long-distance electric travel and helps to provide prospective EV drivers with range confidence. Public charging stations are also important for providing charging options for customers in multifamily dwellings or single-family households with on-street parking.[24] In addition, DCFC stations support the electrification of medium- and heavy-duty fleets, such as transit buses, that have intensive duty cycles.

However, most public charging stations are billed on a commercial rate, which typically includes a demand charge. While the electrical demand (kW) at these stations is very high, energy use (kWh) tends to be low due to the limited number of EVs on the road today. This means that the demand charges tend to dominate the electricity bills for these stations. This phenomenon is particularly true for DCFC stations: empirical analysis by Rocky Mountain Institute demonstrated that demand charges can drive over 90 percent of the costs of operating these stations during summer months in California, making it extremely challenging to recoup costs while EV penetration and station utilization are still low.[25]

To illustrate, consider a DCFC station with two 50-kW ports that occasionally has two vehicles charging at once, for a total of 100 kW of demand. Under a high demand charge of $20/kW, the customer would pay a monthly demand charge of $2,000. Under a more moderate demand charge of $6/kW, the monthly demand charge would be $600.[26] While such demand charges may be tenable for future levels of EV penetration, currently many charging stations experience low utilization rates, with some only being used once every few days.

Under the high demand charge case, a charging station with a low utilization rate of one charge every two days (15 charges per month) would have an operating cost of $142 per charging session, equivalent to a cost of $2.84/kWh. At four times the utilization rate (60 charges per month), the cost would fall to only $39 per session (equivalent to a cost of $0.77/kWh).

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[24] Approximately 25 percent of U.S. households live in multifamily dwellings, and approximately 39 percent of single-family households have no access to charging at home. National Research Council of the National Academies, *Overcoming Barriers to Deployment of Plug-In Electric Vehicles* (Washington, DC: National Academies Press, 2015), 85, https://download.nap.edu/cart/download.cgi?record_id=21725.

[25] 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.

[26] Demand charges generally range from $3/kW to $25/kW. In the Northeast, distribution demand charges average approximately $11/kW.

A more moderate demand charge of $6/kW would still result in a cost per session of $49, assuming only 15 charges per month, or $15 per session assuming 60 charges per month. These results are shown in Table 1 below. Such costs would be difficult, if not impossible to recoup from customers under such low utilization.

Table 1. Impact of a demand charge on a charging station with 100 kw demand

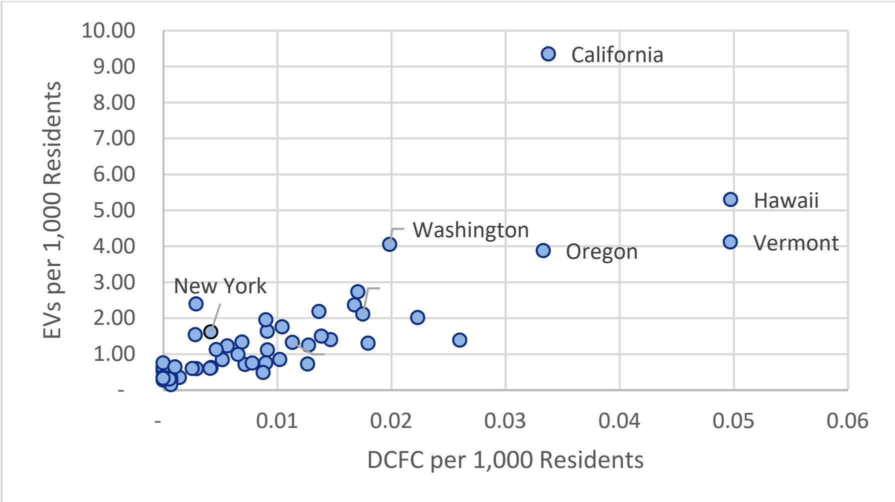
		High Case	Mid Case
Demand Charge ($/kW)		$20	$6
Customer Charge (4/Month)		$70	$70
Energy Charge ($/kWh)		$0.08	$0.08
Energy per Session (kWh)		50	50
15 charging sessions/month	Annual DCFC Bill	$25,560	$8,760
	Cost/session	$142	$49
	Cost/kWh	$2.84	$0.97
60 charging sessions/month	Annual DCFC Bill	$27,720	$10,920
	Cost/session	$39	$15
	Cost/kWh	$0.77	$0.30

To date, DCFC station deployment and EV adoption in New York have been relatively limited. According to data provided by the Alternative Fuels Data Center at the Department of Energy, there are currently 203 DCFC plugs in New York, but only 83 are non-Tesla DCFC plugs.[27] In comparison, there are currently more than 1,300 non-Tesla DCFC plugs in California.[28] The figure below shows the relationship between DCFC and adoption of EVs, controlling for population.

[27] U.S. Department of Energy, Alternative Fuels Data Center, https://www.afdc.energy.gov/data_download, accessed May 2018. Charging stations may contain more than one plug or "port." Often, stations will have two ports. When Tesla charging stations are included, there are 203 in New York compared with 1,775 in California. However, Tesla employs proprietary DCFC charging stations that only Tesla vehicles can access. Therefore, we have focused on charging stations accessible to a wide variety of vehicles.

[28] *Id.*

Figure 6. DC fast chargers (non-Tesla) and EV adoption



Source: Synapse Energy Economics analysis of data from U.S. Department of Energy Alternative Fuels Data Center.

To meet New York's ZEV goal of approximately 800,000 EVs by 2025, many more DCFC will be needed. According to analysis tools developed by the National Renewable Energy Laboratory, New York will require roughly 4,087 DCFC plugs by 2025 to meet its ZEV target.[29]

Where rate design hinders public charging infrastructure, EV adoption is likely to be slow. This begets a chicken-and-egg problem: low levels of EV adoption will result in low charging station utilization and unfavorable business cases for charging station operators, while too few charging stations can slow EV adoption. To address this problem, some utilities have temporarily reduced or eliminated demand charges for customers on EV rates, opting instead to price electricity using TOU rates.

Some have raised concerns that reducing costs for EV charging stations, at least temporarily, could result in cross-subsidization. However, cost shifting will not occur as long as electricity is priced at or above the utility's marginal cost of service.[30] This is because the EV stations are supporting incremental load growth, rather than representing existing load on the system. Existing tariffs are designed to recover embedded costs from existing load, which enables incremental load to be priced at marginal cost, at least during the early years of EV adoption.

[29] To achieve a penetration of 800,000 EVs by 2025, the U.S. Department of Energy's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite estimates that 4,087 DCFC plugs will be required to meet charging demand in New York, using the assumption that 80 percent of customers have access to charging at home. The tool is available at https://www.afdc.energy.gov/evi-pro-lite. EVI-Pro Lite is a simplified version of EVI-Pro, which was developed through a collaboration between the National Renewable Energy Laboratory and the California Energy Commission, with support from the U.S. Department of Energy. EVI-Pro uses personal vehicle travel patterns, electric vehicle attributes, and charging station characteristics to estimate the charging infrastructure required to support various levels of EV adoption.

[30] Any required distribution upgrades directly related to the charging station should also be recovered from the charging station owner in order to avoid shifting these costs on to other customers.

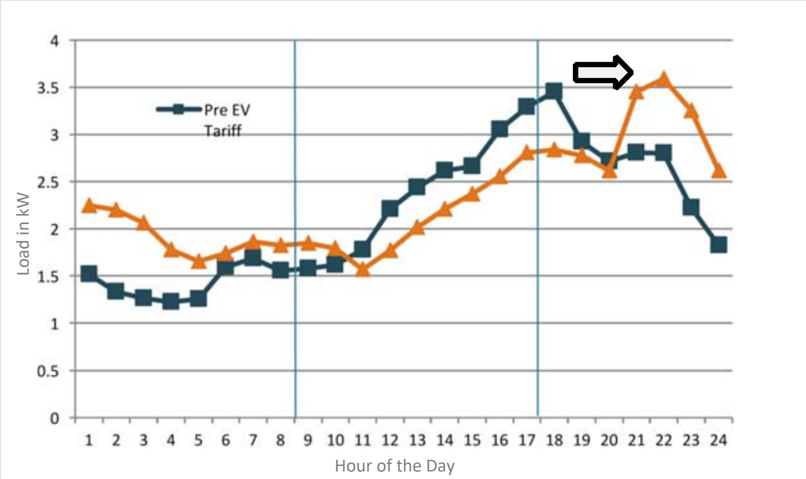
3. IMPLEMENTATION OF EV RATES: LESSONS FROM THE FIELD

3.1. Effectiveness of Time-Varying Rates

As noted above, TOU rates have been widely implemented, and in some cases specifically tailored to EV customers. These rates have proven extremely effective in motivating customers to charge off-peak, since customers can save money doing so and off-peak hours generally align with the hours that customers have parked their car at home.

Most TOU rates are applied to all of a customer's load, rather than just the EV load itself. For residential customers, this is referred to as a "whole-house" TOU rate. To test the response of EV customers to such a rate, Baltimore Gas & Electric (BGE) monitored EV customer load before and after enrolling customers in the whole-house TOU tariff. As the graph below shows, without the tariff, customer load peaked at approximately 6 pm, likely when customers returned home from work and plugged in their vehicles. Once customers received the TOU price signal, average load dropped and the peak shifted to the night-time hours.

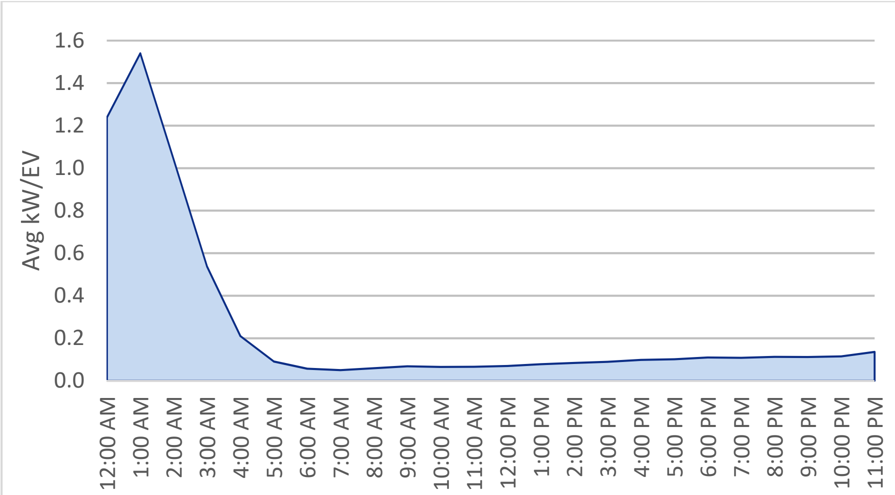
Figure 7. Results of BGE EV tariff pilot



Note: Average weekday customer load before (blue squares) and after (orange triangles) BGE's pilot.
Source: BGE Electric Vehicle Off Peak Charging Pilot, presentation by John Murach, 2017.

The shift in peak load is even more evident for customers on separately metered EV-only rates. For example, under San Diego Gas & Electric's (SGD&E) EV-only rate, the vast majority of load occurs during the middle of the night, as shown in the graph below.

Figure 8. Average load profile for SDG&E customer on EV-only rate



Source: SDG&E Data Response to NRDC DR02-Q6, A.17-01-021.

Both whole-house and EV-only TOU rates have been implemented at all three of California's large IOUs and have been extremely successful in motivating customers to avoid charging on-peak. At Pacific Gas & Electric, 93 percent of charging on the EV-only rate occurs during off-peak hours, while at Southern California Edison, 88 percent of charging is off-peak.[31]

3.2. Design of TOU Rates

Price Ratios

To ensure an effective TOU rate design, the ratio between peak and off-peak prices must be sufficient to motivate customers to shift their load. A study of early-adoption EV customers in SDG&E's service territory found that a peak to off-peak price ratio of 6:1 results in about 10 percent more off-peak charging than a ratio of 2:1.[32]

Reflecting Generation, Transmission, and Distribution Costs

Despite the fact that approximately half of the EVs in the United States are located in California, very few costly grid upgrades due to EVs have occurred to date. According to reports filed by the utilities, grid upgrades due to EVs have totaled less than 0.01 percent of distribution capital costs.[33] This is likely due, at least in part, to the time-varying rates offered by all three of California's IOUs.

[31] Synapse Analysis of Joint Utilities Load Research Report, Dec 2017.

[32] Nexant. 2014. "Final Evaluation of SDG&E Plug-in Electric Vehicle TOU Pricing and Technology Study." Available at www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20&%20Tech%20Study.pdf.

[33] *Id.*

To be efficient, time-varying rates must reflect grid costs. One way in which this is done is by assigning marginal generation, transmission, and distribution costs to each hour of the year. For capacity, this can be done using loss of load expectations for each hour of the year, while for energy, the costs are based on the variable operating costs of different power plants.

The tables below show "heat maps" that reflect hourly marginal costs (in terms of dollars per kWh) for a California utility. The months are shown on the vertical axis, while the hours of the day are shown along the horizontal axis. When the heat maps are combined (Figure 12), the areas of high and low costs can be used to set TOU windows and price differentials.

Figure 9. Marginal energy costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.049	0.048	0.047	0.047	0.048	0.050	0.058	0.062	0.049	0.046	0.045	0.044	0.041	0.042	0.043	0.046	0.057	0.081	0.077	0.071	0.063	0.060	0.055	0.051
February	0.048	0.047	0.047	0.047	0.048	0.050	0.059	0.053	0.047	0.044	0.043	0.043	0.042	0.042	0.043	0.044	0.049	0.067	0.076	0.073	0.065	0.060	0.054	0.050
March	0.047	0.046	0.046	0.046	0.046	0.047	0.052	0.049	0.045	0.040	0.037	0.032	0.027	0.030	0.038	0.040	0.042	0.050	0.062	0.079	0.069	0.061	0.056	0.049
April	0.046	0.044	0.044	0.044	0.045	0.047	0.051	0.044	0.040	0.035	0.032	0.030	0.028	0.029	0.036	0.038	0.040	0.044	0.050	0.069	0.071	0.058	0.052	0.047
May	0.046	0.045	0.044	0.044	0.045	0.047	0.047	0.043	0.039	0.037	0.037	0.037	0.036	0.037	0.038	0.040	0.041	0.045	0.047	0.063	0.071	0.062	0.054	0.048
June	0.047	0.045	0.045	0.045	0.046	0.047	0.046	0.042	0.039	0.038	0.038	0.039	0.038	0.039	0.040	0.042	0.044	0.050	0.048	0.065	0.074	0.070	0.057	0.049
July	0.049	0.046	0.045	0.045	0.045	0.047	0.046	0.043	0.040	0.041	0.042	0.044	0.046	0.049	0.053	0.056	0.060	0.073	0.059	0.096	0.079	0.070	0.060	0.053
August	0.049	0.047	0.046	0.046	0.046	0.048	0.050	0.045	0.043	0.042	0.042	0.043	0.044	0.046	0.049	0.053	0.060	0.074	0.065	0.092	0.080	0.067	0.059	0.053
September	0.049	0.047	0.046	0.046	0.046	0.049	0.055	0.049	0.044	0.042	0.042	0.042	0.043	0.045	0.048	0.050	0.057	0.073	0.090	0.106	0.074	0.062	0.057	0.051
October	0.048	0.047	0.046	0.046	0.046	0.048	0.054	0.054	0.045	0.042	0.041	0.041	0.042	0.043	0.045	0.046	0.048	0.062	0.073	0.079	0.067	0.060	0.056	0.050
November	0.049	0.047	0.047	0.047	0.047	0.049	0.055	0.050	0.046	0.044	0.044	0.043	0.043	0.044	0.045	0.048	0.061	0.089	0.076	0.068	0.063	0.059	0.054	0.050
December	0.050	0.048	0.048	0.048	0.048	0.050	0.057	0.057	0.049	0.047	0.046	0.046	0.045	0.045	0.046	0.048	0.060	0.084	0.077	0.073	0.066	0.062	0.059	0.052

Figure 10. Marginal generation capacity costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.004	0.007	0.010	0.165	0.164	0.009	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.011	0.031	0.002	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.008	0.007	0.054	0.621	0.214	0.004	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.023	0.107	0.249	2.665	1.789	0.441	0.019	0.000	-
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.004	0.011	0.002	0.000	0.000	0.000	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 11. Marginal distribution capacity costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.002	0.001	0.001	0.001	0.001	0.003	0.007	0.006	0.006	0.005	0.003	0.002	0.003	0.003	0.004	0.006	0.006	0.024	0.018	0.015	0.010	0.007	0.008	0.005
February	0.002	0.001	0.001	0.001	0.001	0.002	0.006	0.007	0.006	0.005	0.004	0.004	0.004	0.005	0.004	0.005	0.006	0.014	0.015	0.013	0.008	0.007	0.007	0.005
March	0.002	0.000	0.001	0.001	0.000	0.002	0.005	0.005	0.004	0.002	0.003	0.002	0.002	0.002	0.003	0.004	0.006	0.008	0.010	0.010	0.010	0.008	0.006	0.004
April	0.002	0.001	0.001	0.001	0.001	0.001	0.004	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.006	0.011	0.008	0.010	0.009	0.009	0.007	0.005
May	0.004	0.001	0.001	0.001	0.001	0.001	0.003	0.003	0.003	0.002	0.002	0.003	0.003	0.003	0.004	0.006	0.009	0.020	0.013	0.015	0.016	0.012	0.008	0.006
June	0.005	0.002	0.001	0.001	0.002	0.001	0.002	0.003	0.003	0.005	0.004	0.006	0.004	0.008	0.010	0.016	0.020	0.028	0.020	0.021	0.022	0.021	0.017	0.010
July	0.009	0.005	0.003	0.002	0.003	0.004	0.007	0.007	0.009	0.009	0.012	0.013	0.012	0.019	0.025	0.029	0.043	0.088	0.060	0.043	0.036	0.032	0.024	0.015
August	0.011	0.005	0.003	0.003	0.003	0.006	0.009	0.008	0.009	0.011	0.013	0.014	0.016	0.024	0.031	0.049	0.071	0.095	0.065	0.047	0.040	0.032	0.025	0.017
September	0.007	0.003	0.002	0.002	0.002	0.004	0.010	0.008	0.008	0.009	0.010	0.011	0.015	0.019	0.026	0.040	0.059	0.101	0.044	0.046	0.036	0.025	0.021	0.015
October	0.003	0.001	0.000	0.001	0.001	0.003	0.005	0.005	0.005	0.004	0.004	0.004	0.003	0.006	0.008	0.015	0.022	0.039	0.024	0.030	0.017	0.011	0.008	0.006
November	0.002	0.001	0.001	0.001	0.001	0.002	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.006	0.006	0.009	0.045	0.024	0.014	0.009	0.007	0.007	0.005
December	0.003	0.001	0.001	0.001	0.001	0.003	0.006	0.006	0.006	0.005	0.004	0.004	0.003	0.004	0.005	0.006	0.007	0.041	0.025	0.019	0.013	0.009	0.008	0.006

Figure 12. Total marginal costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.051	0.049	0.048	0.048	0.049	0.053	0.069	0.078	0.055	0.050	0.048	0.046	0.044	0.045	0.047	0.057	0.099	0.169	0.115	0.086	0.074	0.067	0.063	0.056
February	0.050	0.048	0.047	0.048	0.049	0.052	0.064	0.060	0.053	0.049	0.047	0.047	0.046	0.047	0.047	0.051	0.084	0.162	0.133	0.086	0.072	0.067	0.061	0.055
March	0.049	0.046	0.046	0.046	0.046	0.049	0.057	0.054	0.049	0.042	0.039	0.034	0.029	0.033	0.041	0.044	0.065	0.131	0.155	0.103	0.078	0.070	0.062	0.053
April	0.048	0.045	0.045	0.045	0.046	0.048	0.055	0.047	0.042	0.036	0.033	0.032	0.030	0.031	0.039	0.041	0.046	0.102	0.170	0.087	0.080	0.067	0.059	0.052
May	0.050	0.046	0.045	0.045	0.046	0.049	0.050	0.046	0.042	0.039	0.039	0.039	0.039	0.040	0.043	0.045	0.050	0.106	0.156	0.088	0.087	0.073	0.062	0.054
June	0.052	0.047	0.046	0.046	0.047	0.049	0.048	0.046	0.043	0.044	0.044	0.045	0.043	0.047	0.051	0.059	0.066	0.112	0.157	0.215	0.194	0.097	0.074	0.059
July	0.058	0.051	0.048	0.047	0.048	0.050	0.053	0.050	0.049	0.050	0.054	0.057	0.058	0.068	0.077	0.086	0.102	0.203	0.218	0.145	0.134	0.103	0.084	0.068
August	0.060	0.052	0.049	0.049	0.049	0.054	0.058	0.053	0.052	0.053	0.055	0.057	0.059	0.070	0.080	0.104	0.146	0.235	0.249	0.511	0.248	0.101	0.084	0.070
September	0.056	0.050	0.048	0.048	0.048	0.052	0.065	0.057	0.052	0.051	0.052	0.054	0.058	0.064	0.076	0.104	0.185	0.381	1.844	1.225	0.374	0.099	0.079	0.066
October	0.051	0.048	0.047	0.047	0.047	0.051	0.060	0.062	0.050	0.045	0.045	0.045	0.046	0.049	0.052	0.061	0.089	0.180	0.173	0.111	0.084	0.071	0.064	0.056
November	0.050	0.048	0.048	0.048	0.048	0.051	0.060	0.055	0.050	0.048	0.048	0.047	0.047	0.048	0.051	0.079	0.157	0.200	0.099	0.082	0.072	0.065	0.061	0.056
December	0.053	0.049	0.048	0.049	0.049	0.054	0.063	0.063	0.055	0.051	0.050	0.050	0.049	0.049	0.051	0.054	0.122	0.255	0.107	0.092	0.080	0.072	0.067	0.058

When designing TOU rates, it can be instructive to examine distribution costs on a class level as well. In some cases, commercial areas peak during the middle of the days, while circuits serving residential customers peak in the evening. Such findings may suggest establishing different on-peak and off-peak periods for different customer classes.

Another consideration is how wide to set each on-peak and off-peak window. Narrow peak periods and wide off-peak periods provide customers with the most flexibility to shift energy consumption to off-peak hours, but care must be taken to avoid creating a new peak by shifting load to immediately before or after the peak period window.[34] Narrow off-peak windows concentrate energy consumption, which can be problematic when this occurs with large EV loads clustered in small areas. Because EV adoption tends to occur in certain neighborhoods and regions more than others, areas with high penetrations of EVs could see local spikes in demand when all EVs begin charging simultaneously. To avoid this, longer off-peak periods can be beneficial.

3.3. Alternatives to Demand Charges

As noted above, demand charges can be a barrier to both DCFC as well as workplace charging. For this reason, some utilities have proposed to reduce the demand charge for these customers, or to temporarily suspend the demand charge (instead shifting the cost recovery to the energy charge). For example, in California, Southern California Edison proposed to exclude a demand charge from its EV rate designs. Instead, it is recovering costs through TOU rates for a period of five years. The demand charge would then be gradually phased back in over the next five years. Similarly, in New York, the Consolidated Edison Company of New York's (Con Edison) proposed to provide a temporary discount to public fast charging stations (with an aggregate capacity of at least 100 kW) through its Business Incentive Rate program. This program reduces customers' delivery charges by nearly 40 percent for a period of up to seven years.[35] The New York Public Service Commission approved this discount, noting the importance of publicly available EV charging stations in supporting adoption of EVs. The Commission also stated that the discount would "help mitigate the high cost of EV charging station operation in an immature market with low charging station utilization."[36]

[34] To mitigate the sharp rise in demand at the beginning of the off-peak period, some utilities are exploring managed charging. Managed charging would allow a utility (or third party) to remotely reduce the rate of vehicle charging in a manner similar to traditional demand response programs. However, the cost of the communications infrastructure necessary to relay such signals may be cost prohibitive. *See:* Erika Myers, "Utilities and Electric Vehicles: The Case for Managed Charging" (Smart Electric Power Alliance, April 2017), 5, https://sepapower.org/resource/ev-managed-charging/. In some cases, utilities assign customers a specific time to start charging to avoid a sudden surge in demand. Conversation with Pasi Miettinen, President and CEO of Sagewell, Inc.

[35] To be eligible, customers must not impose substantial additional distribution facility costs on the system, unless those costs are borne by the customer.

[36] New York Public Service Commission, Order Approving Tariff Amendments, Case 17-E-0814, April 24, 2018, page 6.

3.4. Metering Technologies for EV-Only Rates

Customers may be hesitant to enroll in a whole-house TOU rate plan because it can be a challenge to shift certain energy-intensive behaviors from expensive on-peak periods to cheaper off-peak periods. It is much easier for customers to monitor and control EV charging than appliances in other parts of the home. For this reason, customers may prefer an EV-only TOU rate to a whole-house rate.

While customers on a whole-house TOU rate plan would only need a single meter to monitor electricity use, EV-only rates require a separate revenue-grade meter or the use of submetering technology to record electricity use that is specifically attributable to EV charging. Each metering option has certain advantages and drawbacks. While a second utility meter is a straightforward option, the costs of installation can be prohibitively high, and customer charges associated with a second meter can deter customers. Submetering is promising, particularly if installation costs can be reduced further and data transfer issues can be resolved. We discuss these and other metering options below.

Second Meter for EV Charging

Standard utility practice for EV-only rate plans is to combine TOU rates with the installation of a second meter designated specifically to monitor EV charging. Some utilities provide the EV billing meter free of charge while others require that customers pay for it through an up-front fee or additional monthly charge. Although a second meter makes it easy to apply TOU rates only to EV charging, the additional meter and installation charges present a significant barrier to widespread adoption of EV-only rates.

Regardless of who pays for the second meter, customers are generally responsible for the installation costs, which include the meter socket(s) with a lever bypass and conduit and wiring performed by an electrician. The installation can cost thousands of dollars up front for customers, eliminating virtually any of the fuel cost savings associated with the EV-only rate. The Minnesota Public Utilities Commission notes that residential customers typically spend between $1,725 and $3,525 on electrical wiring and metering costs to enroll in Xcel Energy's current EV tariff.[37]

As a result of the high costs associated with separately metered programs, enrollment has been low to date in many jurisdictions.[38] For example, as of April 2017, Xcel Energy (Minnesota) had only enrolled 95 customers on its second-meter EV rate over the course of nearly two years.[39] In recognition of these

[37] Minnesota Public Utilities Commission, Order Approving Pilot Program, Granting Variance, and Requiring Annual Reports. Docket No. E-002/M-17-817, May 9, 2018, page 2.

[38] Utilities offering second-meter EV rates include Southern California Edison, PG&E, SDG&E, Detroit Edison, Consumers Energy, Xcel MN, and Dominion Energy.

[39] Minnesota Public Utilities Commission Staff, Briefing Papers, In the Matter of Xcel Energy – Electric – Petition for Approval of a Residential EV Service Pilot Program, E002/M-17-817, April 12, 2018, page 14.

barriers to enrollment, Xcel has initiated a submetering pilot to attempt to reduce costs and provide additional options to customers.[40]

In a similar case, Dominion Power had to extend its pilot EV pricing plan due to low enrollment. Dominion's pilot consists of two EV pricing plan options: an EV-only TOU rate and a whole-house TOU rate. The EV-only rate requires a separate meter, while the whole-house TOU rate requires an upgraded meter that is capable of recording interval usage. Dominion provides the meters to customers at no charge, but customers are responsible for the installation costs. [41] Customers on the EV-only rate also face an additional monthly customer charge.

Dominion's pilot was originally approved by the Virginia State Corporation Commission in 2011 with an enrollment limit of 1,500 participants. As of October 2013, the pilot program had 230 enrolled participants, but Dominion noted that EV adoption levels in its service territory had grown by more than 700 percent over the course of the original program.[42] The Commission approved the extension to allow more time for the pilot to reach full enrollment and to enable Dominion to more fully analyze the results. In 2016, five years after commencement, the pilot closed enrollment at only 600 customers – less than half of the cap.

Both of these examples illustrate the magnitude of the cost barrier associated with using a second meter to provide EV rates. Because the cost of installing the second meter can be such a deterrent, utilities and regulators have started to seek other options, such as submetering. Submetering offers much promise, but currently faces cost challenges of its own. Another option is to utilize the metering equipment in the EV itself (on-board metering), but this has not been explored to the same extent as other forms of submetering.

Submetering Technologies

Submetering is similar to having an additional meter, except that the submeter is located between the primary meter and the EV. This allows the EV load to be billed on a time-varying rate, while the rest of the household usage is billed on a standard rate. Submeters are not yet widely used for EV-only tariffs, but California has conducted extensive testing on the technology, and several utilities are piloting

[40] Xcel Energy, In the Matter of Xcel Energy – Electric – Petition for Approval of a Residential EV Service Pilot Program, E002/M-17-817, November 17, 2017.

[41] Under the EV-only rate, a dedicated hard-wired circuit is required, and an electrician may recommend changes to the existing electrical set up, which would incur additional costs. Under the whole-house TOU rate, service upgrades may be required due to the additional energy consumed at a home, which would incur additional costs from an electrician.

[42] Rivera-Linares, Corina. 2013. Dominion Virginia Power seeks to extend electric vehicle pilot program by two years. TransmissionHub. Available at: https://www.transmissionhub.com/articles/2013/11/dominion-virginia-power-seeks-to-extend-electric-vehicle-pilot-program-by-two-years.html

submetering for EV tariffs.[43] The current technology options and costs associated with submeters include:

1) Stand-alone submeters like the WattBox™ from eMotorWerks, with a cost of approximately $250;[44]
2) Submeters integrated with the EV supply equipment ("EVSE," colloquially "charging station"). At-home EVSE are generally Level 2 charging stations such as the JuiceBox™ from eMotorWerks with a cost of approximately $899,[45] or the ChargePoint Home from ChargePoint with a cost of approximately $674; [46] and
3) Mobile (in-car) submeters such as the FleetCarma C2 device.

Installation of both stand-alone and EVSE-integrated submeters typically requires an electrician and will incur an additional cost. In contrast, FleetCarma's C2 device is "plug-and-play," allowing the EV owner to simply plug it into the on-board diagnostics port found under the dash of the vehicle. All three submeter types collect EV charging data and use WiFi or a cellular network to record and transmit usage data to third-party vendors or directly to the utility.

California has actively sought to promote the development of submetering technologies as a lower cost option to traditional metering options. To that end, a two-phase multi-year pilot was initiated in California to test submetering functionality. The two-phase pilot ran from 2014 to 2018 and provided opportunities to identify submetering challenges and work to overcome those barriers. In addition to California's pilot, EVSE-embedded submetering has been implemented for EV off-peak charging rewards at Belmont Light in Massachusetts and will be soon be tested in Minnesota. Mobile (in-car) submeters are currently in use for Con Edison's Smart Charge Rewards program and have also been used for pilot in Toronto and Arizona.[47]

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[43] California is in Phase II of its submetering pilot, while Xcel Minnesota recently obtained approval to proceed with its submetering pilot. Submetering has also been tested by some municipal utilities, such as Belmont Light in Massachusetts.

[44] Cook, J. et al. 2016. California Statewide PEV Submetering Pilot – Phase 1 Report. Nexant. Prepared for the California Public Utilities Commission. Page 31.

[45] Pricing as of May 2018 on eMotorWerks website store: https://emotorwerks.com/store/residential/juicebox-pro-75-smart-75-amp-evse-with-24-foot-cable?gclid=CjwKCAjw_47YBRBxEiwAYuKdw3px-uQc2d5KVUzQHr-KOnLCI3sNmkUyDNm6e6VifNu-PrYt15dCmhoCtM8QAvD_BwE

[46] Pricing as of May 2018 on ChargePoint website store: https://store.chargepoint.com/chargepoint-home

[47] Toronto's program is called ChargeTO, and the results of its pilot are available from FleetCarma here: https://www.fleetcarma.com/resources/chargeto/. The Salt River Project's pilot results are available here: https://www.srpnet.com/newsroom/releases/011018.aspx.

Stand-Alone and Embedded EVSE Submetering

<u>Technical Challenges and Progress</u>

Several submetering pilot programs have noted issues with data transmission associated with WiFi, which can result in problems with customer bills. Almost all of the participants in Phase 1 of California's Plug-In Electric Vehicle Submetering Pilot, which ran between 2014 and 2016, used stand-alone submeters with WiFi for data transmission. A common problem was spotty data coverage, submeters going offline, and software issues with data server. Analysis of a sample of submeters in use suggested that 10–20 percent experienced some sort of data accuracy problem over the course of the Phase 1 Pilot.[48]

Belmont Light in Massachusetts reported a similar experience, stating that it was unable to provide accurate rebates to customers for off-peak EV charging due to WiFi connectivity and data access issues with stand-alone submeters.[49] However, participants with EVSE embedded submeters did not report the same data issues.[50] Belmont Light was also able to verify customer charging via smart meter data, whereas the California utilities reviewed program data from third-party Submeter Data Management Agents, who measured EV electricity use and delivered data to the utilities on a daily basis for billing purposes.

The California Phase 1 submetering pilot was a relatively small-scale pilot with only 241 participating customers. Phase 2, which began in January 2017 and concluded in April 2018, was designed to address some of the issues encountered in Phase 1 and test even more stringent levels of metering accuracy. For example, the accuracy threshold for submeters was lowered from 5 percent to 1 percent for Phase 2, as recommended in the Phase 1 evaluation report.[51] This threshold eliminates most of the stand-alone submetering technologies and requires the use of a submeter integrated with the EVSE.

In addition to the submetering pilot, SDG&E plans to deploy 3,500 EVSE with embedded submeters for its *Power Your Drive* vehicle-to-grid integration pilot and up to 60,000 EVSE with embedded submeters for its residential charging program.[52] Currently vendors are undergoing multi-month testing to ensure that the EVSE can provide dynamic, hourly rates (on a day-ahead basis) to the driver, allow the customer to set charging needs, and collect and transmit the hourly usage data to the utility.[53] These advanced

[48] Cook, J. et al. 2016. California Statewide PEV Submetering Pilot – Phase 1 Report. Nexant. Prepared for the California Public Utilities Commission. Page 12.

[49] Conversation with Rebecca Keane, Energy Resources Analyst at Belmont Light. April 26, 2018.

[50] Conversation with Rebecca Keane, Energy Resources Analyst at Belmont Light. April 26, 2018.

[51] Jonathan Cook et al., "California Statewide PEV Submetering Pilot – Phase 1 Report.," Prepared for the California Public Utilities Commission (Nexant, April 1, 2016), 13.

[52] California Public Utilities Commission, Decision on Transportation Electrification Standard Review Projects, Decision 18-05-040, May 31, 2018.

[53] SDG&E. Electric Vehicle-Grid Integration Pilot Program ("Power Your Drive") Third Semi-Annual Report of San Diego Gas & Electric Company, Rulemaking 13-11-007, September 19, 2017.

technical requirements have required that EVSE vendors develop custom software solutions, and they will certainly help to further the state of the technology.

EVSE-Embedded Submetering Costs

Although submetering is intended to lower costs to customers, there are often substantial costs associated with installation for submeters embedded in Level 2 EVSE. These costs can be a deterrent to drivers. In California, Nexant found that installation costs must be kept low and charging savings must be approximately $15/month, on average, to be attractive to EV owners. Increasing the installation costs of a submeter by $150 reduced the likelihood of program enrollment by one-third, while an increase of $300 reduced the likelihood of enrollment by one-half.[54]

Cost issues were less important for Belmont Light, where many of its customers that participated in the pilot program already had Level 2 chargers that could be integrated with smart meters to provide EV charging data to the utility. These customers received a rebate from the utility of $5/month in exchange for a promise to shift charging to off-peak hours. (Note that Belmont Light does not currently have TOU rates.) Customers were allowed up to three charges per month during on-peak times to retain this incentive.[55]

Mobile Submeters

Mobile (in-car) submeters offer another option for utilities to gather information on the charging and driving patterns of EV owners. Con Edison currently offers an off-peak charging incentive program to EV customers using the FleetCarma C2 device, which is installed by plugging it into the vehicle's on-board diagnostics port. The device then collects vehicle charging and driving data by decoding signals from the vehicle's internal computer system and sends the data securely to FleetCarma servers over the cellular network.

Rather than apply a TOU rate structure, the SmartCharge NY program rewards participants with e-gift cards for off-peak charging behavior anywhere in the Con Edison service territory (EV owners do not have to be Con Edison customers).[56] Con Edison launched the program in April 2017 with 100 EVs with the C2 device. The program was expanded to full scale in July 2017, and then in September 2017 the *Bring Your Own Charger Fleet Program* component was launched. As of January 2018, there were 875 EVs enrolled in the program (431 private EVs and 444 New York City electric fleet vehicles), representing

[54] Cook et al., "California Statewide PEV Submetering Pilot – Phase 1 Report.," 10.

[55] Going forward, Belmont Light has combined its customers into one group and increased its incentive to $8/month for off-peak charging. Conversation with Rebecca Keane, Energy Resources Analyst at Belmont Light. April 26, 2018.

[56] Sherry Login, "SmartCharge New York," January 22, 2018, 4, http://www.state.nj.us/bpu/pdf/publicnotice/stakeholder/20180205/NJ%20EV%20Stakeholders%20Meeting_January%2022%202018%20Con%20Ed.pdf.

15 percent of the EVs in Con Edison's service territory. By charging off-peak, Con Edison estimates the program has achieved a 0.63 MW peak load reduction.[57]

Through the use of a mobile submeter and rewards program, SmartCharge NY avoids the need for electricians or utility crews to install equipment, does not require a separate EV tariff, does not require complex billing processes, and avoids additional customer charges from the utility. The rewards offered for off-peak charging may also be updated as needed with no filing requirements, and EV owners do not have to be utility account holders.[58] Importantly, Con Edison has found that SmartCharge NY has higher enrollments than its TOU programs, with 875 vehicles enrolled in nine months. In contrast, the TOU Rate with one-year price guarantee had 55 customers enrolled over the course of four years, and the EV-only TOU rate program has only four customers enrolled.[59]

A key drawback of this technology and program type is its cost. Based on program data provided by Con Edison, the annual non-incentive costs of the program total approximately $250 per year per EV customer enrolled.[60] In other jurisdictions with lower enrollments, the non-incentive costs have been estimated to be many times higher.[61] Other challenges to greater program enrollment include: customer awareness, privacy concerns (FleetCarma attempts to manage this issue by anonymizing the data provided to utilities), difficulties installing the C2 device in Tesla vehicles, and the limitation to light-duty vehicles.[62] Next steps for the SmartCharge NY program include a four-month pilot program evaluating the viability of cloud-based technology as an alternative to the C2 device.[63]

On-Board Metering

On-board metering (or "on-vehicle metering") could offer a low-cost alternative submetering approach but requires more testing and support to mature. By using the vehicle's built-in metering and telemetry capabilities, on-board metering could avoid the need for a separate, external device and communications infrastructure altogether. In comments filed in California, GM stated "On-vehicle metering is a consideration that could provide the most cost-effective, communications capable,

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57 Login, 16.

58 Login, 18.

59 Information on TOU rates can be found at: https://www.coned.com/en/save-money/energy-saving-programs/time-of-use.

60 Login, 3.

61 For example, NV Energy's estimated administrative cost for the program totaled approximately $1,400 per customer. This high cost is likely related to the small scale of NV Energy's proposed program, which would only provide incentives to 300 EV customers. *See:* Direct Testimony of Will Toor on behalf of Nevadans for Clean Affordable Reliable Energy, Docket 18-02002, May 8, 2018, page 11.

62 *Id*. Slide 19.

63 *Id*. Slide 20.

regulatory compliant and utility/customer friendly solution for measuring and recording BEV and PHEV electricity consumption."[64]

Although the potential for on-board metering has been noted both in the United States and abroad, it has yet to gain widespread attention or adoption, except for in specific applications such as aggregated demand response. A key barrier to the use of on-board metering for implementing time-varying rate structures is the requirement for revenue grade metering and the implications for billing responsibility. Specifically, metering requirements generally follow American National Standards Institute (ANSI) standards for metering accuracy of +/- 0.2% or +/- 0.5% and require rigorous testing and certification processes. Further, resolution of billing disputes where submeters are involved can be complicated.[65]

To overcome these barriers, the need for stringent metering standards for submetering may need to be revisited and clear rules for dispute settlement established. California's submetering protocol proceedings and pilots are currently exploring some of these issues. However, they primarily focus on embedded EVSE submetering, rather than on-board vehicle metering.[66]

While on-board metering has not been developed to the point where it is used for traditional rate structures, it is being used or piloted for applications where metering requirements are less onerous. These applications include providing demand response where the performance of multiple EVs are aggregated together and rebate programs that provide customers with rewards (such as gift cards) for off-peak charging outside of the traditional utility billing process.[67]

3.5. Maximizing Customer Enrollment in EV Rates

Low levels of customer enrollment in EV rates can prevent achievement of the substantial benefits associate with TOU rates. Enrollment levels can be low due to several reasons, including:

- Rates that are too complex to be easily understood by customers,
- Customer inertia (the "hassle factor"),
- Lack of awareness of the rate, and
- Uncertainty regarding whether customers will save money on the new rate.

As discussed in Chapter 0, TOU rates are the most widespread time-varying rate in use today, in part because of their simplicity and customer acceptance. Sometimes TOU rates are combined with critical peak pricing to provide even more targeted price signals, which has also been successful. Although there

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[64] GM. Comments in response to Rulemaking (R.) 09-08-009 "The Utility Role in Supporting Plug-In Electric Vehicle Charging" Staff Issues Paper, August 30, 2010.

[65] Communication with George Bellino, June 7, 2018.

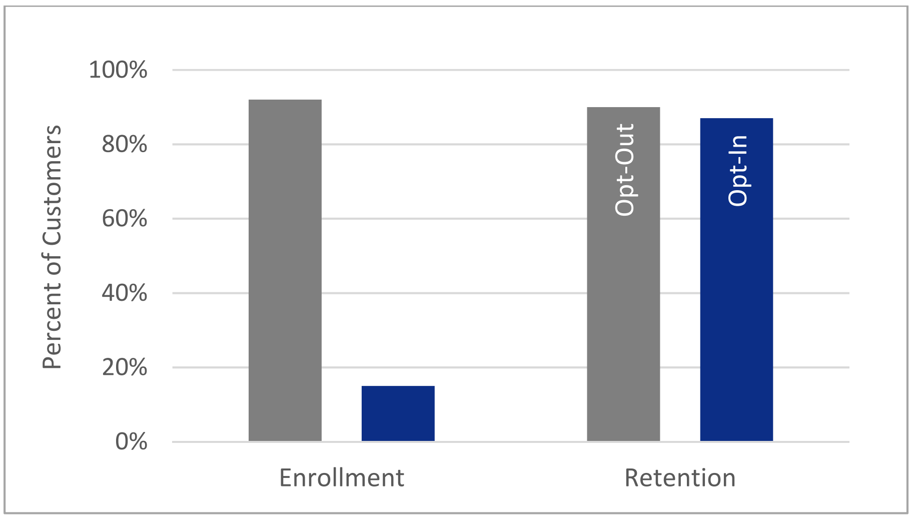
[66] California's submetering pilot program documents are available at http://www.cpuc.ca.gov/general.aspx?id=5938.

[67] The authors understand that Con Edison is currently exploring on-board metering for its off-peak rebate programs.

is theoretical appeal in more dynamic rates (such as those that vary by hour or by location), such rate designs are generally too complex for residential customers and likely to lead to low enrollment.[68]

Due to customer inertia, low levels of customer enrollment are common when customers are required to actively opt-in to the rate, but high levels of customer enrollment can be achieved through defaulting customers onto a rate (through an opt-out design). This has been found to be true for both EV customers and non-EV customers. For example, an analysis of 10 time-varying rate pilots found that, under an opt-in rate structure, less than 20 percent of customers enrolled. In contrast, the two utilities that employed a default (opt-out) design attained enrollments of more than 90 percent of customers. After a year, the default design retained a slightly larger proportion of customers than even the opt-in structure.[69]

Figure 13. TOU enrollment and retention levels



Until customers become more familiar with time-varying rates, opt-in programs will likely be the norm. Where opt-in rates are used, utilities must do more than simply establish the rate—they must actively encourage enrollment through a combination of education, outreach, and incentives. In addition, it is important to ensure that utility incentives, auto dealership incentives, and customer incentives are all aligned.

Activities to maximize EV customer enrollment in EV rates may include:

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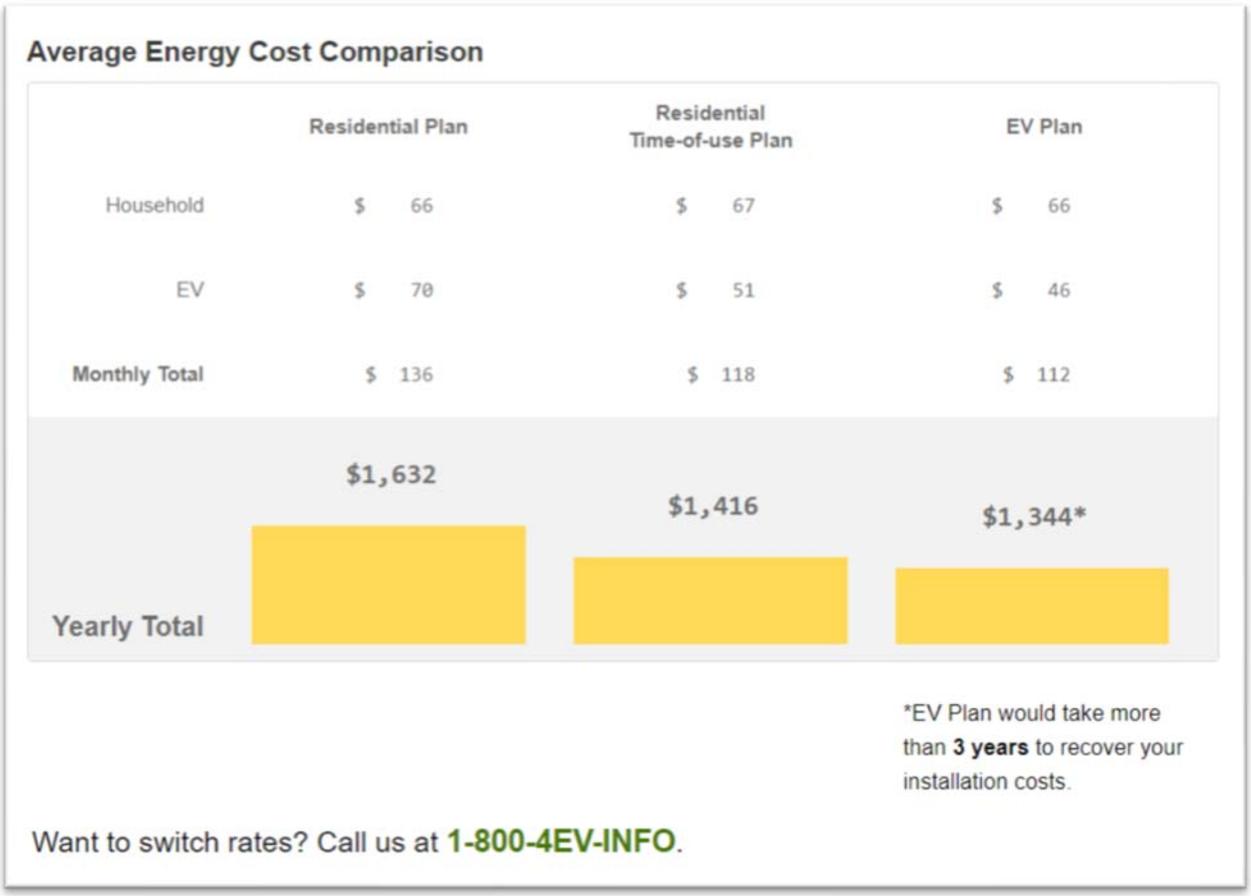
[68] For example, in 2017 SDG&E proposed a residential EV rate that would include both an hourly dynamic rate and critical peak pricing, the timing of which would vary by circuit across the utility's territory. Regulators rejected the rate design, stating "While some early adopting customers may be savvy enough to monitor and respond to daily price signals, SDG&E has provided no evidence suggesting the average residential customer will respond to a different charging period every day based on day-ahead pricing signals." *See: Proposed Decision of ALJs Goldberg and Cooke, Decision on the Transportation Electrification Standard Review Projects, Application 17-01-020 et al., March 30, 2018, page 47.*

[69] Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies; Smart Grid Investment Grant Program; November 2016.

- **Website Tools:** Determining whether an EV rate will save a customer money is a complex quantitative exercise. Rate comparison calculators, such as Southern California Edison's Electric Vehicle Rate Assistant Tool, provide an easy way for customers to compare their cost savings over several different rate options. The image below shows a screenshot of sample results from the Rate Assistant Tool—a simple web-based tool that guides customers through the rate comparison process.[70] We note that the rate assistant tool also provides a dedicated EV customer service phone number that customers can call to enroll.

Figure 14. Example web-based rate comparison calculator



- **Dealership Education and Incentives.** Lack of familiarity with EVs can lead auto sales representatives to shy away from selling EVs, or even to actively discourage purchase of EVs.[71] Furthermore, auto sales representatives often have little to no understanding of the rates available to EV drivers. For example, Consumer Reports found that "When asked how much it would cost to charge an EV, only about 19 percent of salespeople

[70] https://www.sce.com/wps/portal/home/residential/electric-cars/charging-and-installation/EV-Rate-Assistant

[71] John Voelcker, "Many Car Dealers Don't Want To Sell Electric Cars: Here's Why," *Green Car Reports*, February 14, 2014, https://www.greencarreports.com/news/1090281_many-car-dealers-dont-want-to-sell-electric-cars-heres-why.

gave reasonably accurate answers."[72] In California, a dealership training curriculum was developed and is conducted by a collaboration of organizations, and a $250 dealership incentive is provided for each EV purchase in which the customer also signs up for an EV rate.[73]

- **Direct Outreach to EV Customers.** It can be difficult for a utility to identify which of its customers have purchased an EV. To identify customers, it may be possible for utilities to work with state agencies to access Department of Motor Vehicle registration records and directly contact EV drivers. Some utilities also offer gift cards or other rewards to customers. For example, Salt River Project in Arizona provides EV customers with a $50 gift card simply for signing up for the utility's EV mailing list. Establishing these points of contact can be an important first step to educating and enrolling customers in an EV rate.

- **Price Guarantees:** Many utilities offer a price guarantee for the first six months to a year that a customer enrolls in a time-varying rate. These guarantees ensure that the customer will not pay more on the time-varying rate than they would on a standard rate, thereby reducing the customer's risk of signing up for a rate structure that is new to them.

[72] Charles Morris, "Are Auto Dealers the EV's Worst Enemy?," *Charged Electric Vehicles*, September 9, 2014, https://chargedevs.com/features/are-auto-dealers-the-evs-worst-enemy/.

[73] The monetary incentive was recently approved for SDG&E. *See:* California Public Utilities Commission. Decision on the Transportation Electrification Priority Review Projects. Decision 18-01-024. January 11, 2018, page 39.

4. ASSESSMENT OF NEW YORK UTILITY EV RATE PROPOSALS

Recent utility attention to EV rate design in New York State has arisen partly in response to a state law requiring that each New York electric IOU file an application to establish a residential tariff for the purpose of charging EVs no later than April 1, 2018.[74] This same law allows for periodic updates to residential EV rates, and it requires that IOUs regularly report on the number of customers taking service under the residential EV tariff and the total amount of electricity delivered under the tariff.[75]

In March 2018, all six New York electric IOUs submitted filings in compliance with requirements to develop residential EV tariffs. Three of the utilities—Con Edison, Niagara Mohawk Corporation d/b/a National Grid (National Grid), and Orange and Rockland Utilities, Inc. (O&R)—stated that their compliance was based on previously proposed or implemented EV TOU rates.[76] The other three—Central Hudson Gas & Electric Corporation (Central Hudson), New York State Electric and Gas Corporation (NYSEG), and Rochester Gas and Electric Corporation (RG&E)—proposed new residential EV tariffs for consideration by the New York Public Service Commission.[77]

Below, we assess the tariffs that the New York IOUs propose to use to comply with the requirement that they develop and maintain residential EV rates. We evaluate both design considerations and the likely impact of these tariffs on customer fuel costs.

4.1. Positive Aspects of Residential EV Rate Proposals

Each of the proposed residential EV rates shares certain important and positive characteristics. Chief among these are the inclusion of a TOU rate structure and a price guarantee mechanism.

Overarching Rate Design Structure

Each of the proposed residential EV tariffs incorporates a reasonable rate design structure. Specifically, each proposed rate uses a TOU structure and does not include a demand charge. As discussed previously, TOU rate designs combine efficient price signals with simplicity to provide an accessible price signal for residential customers. TOU energy rates provide a clear incentive for EV customers to charge their vehicles during low-cost, off-peak hours without requiring that these customers pay constant attention to their hour-to-hour energy usage. Customer charges should generally be kept to low levels

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[74] New York Public Service Law Section 66-o(2)

[75] New York Public Service Law Section 66-o(6)

[76] Con Edison Compliance Filing Regarding Compliance with Public Service Law § 66-o. March 30, 2018; National Grid Compliance Filing Regarding Public Service Law Section 66-o(2) – Residential Tariff for Electric Vehicles. March 30, 2018; O&R Compliance Filing Regarding PSL§ 66-o. March 30, 2018. To date, adoption of these existing TOU rates has been minimal. For example, Con Edison recently indicate that fewer than 2,000 customers, or less than 0.1 percent of residential customers, have adopted its residential TOU rate. See Con Edison AMI Metrics Report Appendix 18. April 30, 2018. Filed in New York Public Service Commission Docket 16-00253.

[77] Central Hudson Letter to Public Service Commission Regarding Compliance Filing to Effectuate Amendments to Public Service Law § 66. March 29, 2018.; NYSEG & RG&E Compliance Filing Regarding Plug-In Electric Vehicle Tariff. March 30, 2018.

but are a reasonable mechanism for recovering costs that are clearly tied to the number of customers on a utility system, such as costs for installing and reading meters.

It is worth noting that the state law requiring the establishment of residential EV rates does not include any requirements or guidance regarding the design of those rates. It is therefore commendable that the New York IOUs developed TOU rate structures.

Price Guarantee

Each of the New York IOU proposals includes a whole-house TOU rate with a one-year price guarantee. Under this mechanism, customers switching onto the whole-house TOU rate have the option of comparing their first-year charges to the charges they would have incurred if they had remained on their original rate. If they pay more under the TOU rate, the customers will be eligible to receive the difference between what they actually paid and what they would have paid under the standard rate. This feature provides the type of assurance that is helpful for convincing wary customers to switch onto a TOU rate. This insurance against a bad outcome is particularly important in the context of new rate options that a customer must be enticed to adopt (rather than being defaulted onto), as is the case in New York.

4.2. Fuel Cost Savings Under EV Rates

Even with a one-year price guarantee, EV owners are only likely to switch to and remain on TOU rates if those rates provide noticeable savings relative to their standard rates. Without such savings, there is little incentive for customers to transition to a new rate, or to remain on that rate.

Fuel cost savings are also one of the primary motivators of EV purchase decisions.[78] Providing greater fuel cost savings from charging an EV on a TOU rate relative to filling up a gas-powered vehicle incentivizes customers to purchase an EV and contribute to the achievement of New York's EV adoption policy goals.

To determine whether the proposed rates would provide meaningful fuel cost savings, we estimated per-vehicle annual fuel cost savings of charging an EV under the IOUs' proposed TOU rates relative to both charging an EV on a standard rate and operating an ICE vehicle.

Our analysis sought to account for all the various fuel cost components faced by EV owners, including incremental customer charges, TOU delivery charges, standard offer service supply charges, and various miscellaneous volumetric charges.[79] We assumed ICE fuel costs based on average monthly regional gas

[78] Singer, "The Barriers to Acceptance of Plug-in Electric Vehicles: 2017 Update."

[79] These include Merchant Function charges, Clean Energy Standard charges, System Benefit Charges, and Revenue Decoupling adjustments.

prices from 2017.[80] Monthly assumptions for average vehicle miles traveled were derived from research conducted by the AAA Foundation for Traffic Safety.[81]

Our analysis focused on average savings for an owner of a typical full battery electric vehicle (BEV) with a range of 100 miles, similar to a Nissan Leaf or a BMW i3. Based on the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2018, we assume that 100-mile BEVs achieve an average fuel efficiency of 93 miles per gallon of gasoline equivalent, or 2.8 miles per kWh.[82]

We evaluated savings under two charging profiles for customers on EV TOU rates: one in which all charging takes place during off-peak hours, and one consistent with the typical charging patterns of California EV customers facing TOU rates, in which most – but not all – charging occurs during off-peak hours. The latter profile is more likely to be representative of actual customer charging behavior. Consideration of this more realistic charging behavior is important for ensuring that customers will have a reasonable opportunity to achieve fuel savings, even when they must occasionally charge during on-peak hours. This aspect of EV rate design was recognized by the California Public Utilities Commission, who wrote:

> Although our goal is to maximize off-peak charging, we appreciate that, at times, Electric Vehicle owners will need to charge their vehicles during peak periods or may simply find it convenient to do so. To ensure broad consumer acceptance of Electric Vehicles, it is crucial to accommodate the Electric Vehicle owners' charging needs and preferences…[83]

We discuss the results of our analysis in the following sections.

Results: TOU Savings Relative to Charging on Standard Rate

Whole-House TOU Rate

Our analysis indicates fuel cost savings provided by the IOUs' whole-house residential EV rates relative to standard residential rates vary substantially across utilities. Figure 15 presents fuel cost savings by utility and charging pattern.

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[80] New York State Energy Research and Development Authority. Monthly Average Motor Gasoline Prices. https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices/Motor-Gasoline/Monthly-Average-Motor-Gasoline-Prices. According to this date, statewide gasoline prices averaged $2.49 per gallon in 2017.

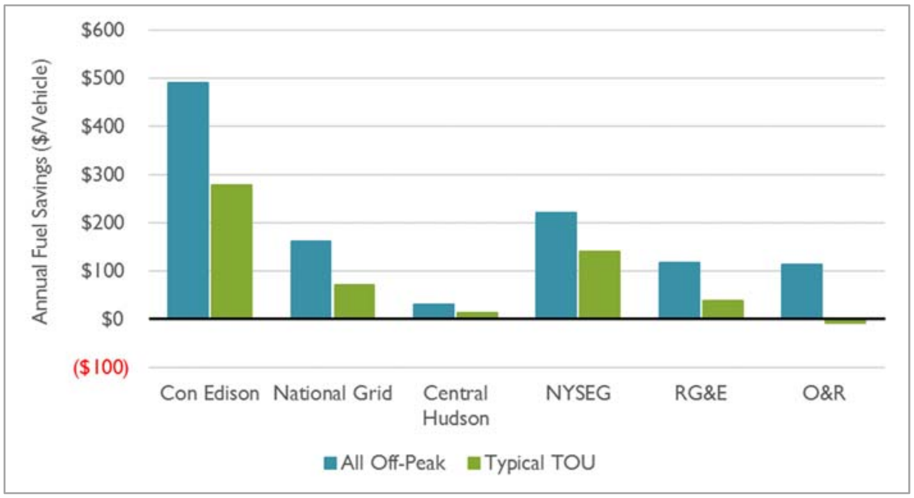
[81] AAA Foundation for Traffic Safety, American Driving Survey 2015-2016. https://aaafoundation.org/wp-content/uploads/2018/02/18-0019_AAAFTS-ADS-Research-Brief.pdf; AAA Foundation for Traffic Safety, American Driving Survey 2013-2014. https://newsroom.aaa.com/wp-content/uploads/2015/04/REPORT_American_Driving_Survey_Methodology_and_year_1_results_May_2013_to_May_2014.pdf. Based on this data, the average vehicle travels 11,381 miles per year.

[82] U.S. EIA. AEO 2018 Table 41. https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_41.xlsx .We note that this assumption is likely conservative, as many new EVs have fuel economies of 3.3 miles per kWh.

[83] California Public Utilities Commission, D.11-07-029 Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2, July 14, 2011, 15.

Assuming that all charging occurs off-peak, customers of all utilities would benefit from fuel cost savings, but the magnitude of these savings varies greatly across utilities. The rates proposed by Con Edison and NYSEG offer the greatest potential savings, with Con Edison customers experiencing annual fuel cost savings of approximately $500. Customers of RG&E, National Grid, and O&R experience savings of about $100 per year. In Central Hudson's territory, where there is a relatively small difference between on-peak and off-peak TOU rates, average annual savings amount to less than $50 even if all charging takes place during off-peak hours.

Figure 15. Whole-house TOU rate annual fuel cost savings relative to standard rate



Source: Synapse Energy Economics analysis.

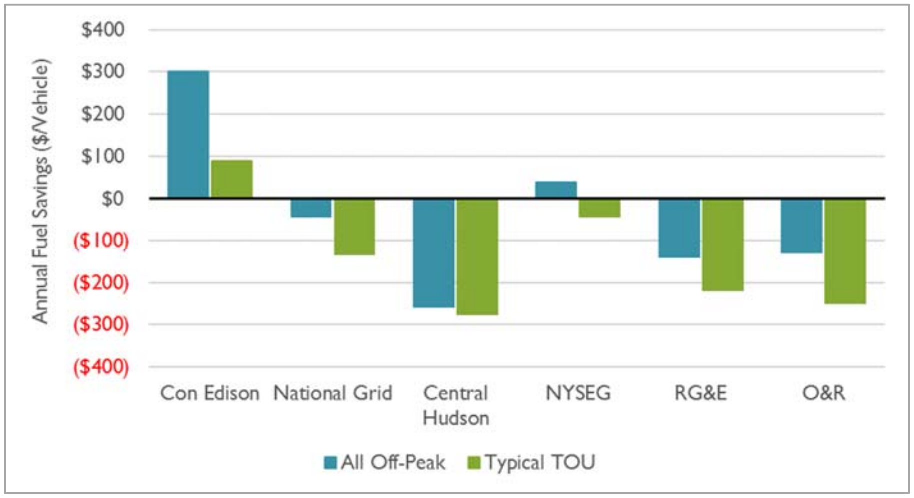
Under the scenario in which most, but not all, charging occurs during the off-peak period, the fuel cost savings are reduced substantially. A typical 100-mile BEV customer would be expected to save an average of approximately $250 per year at Con Edison. In contrast, we would expect that a typical O&R customer would experience a small *increase* in fuel costs from switching onto the proposed residential EV rate. Meanwhile, an average EV customer of Central Hudson or RG&E would experience fuel cost savings of less than $50 per year from switching rates. The benefits of such low savings in the Central Hudson and RG&E territories may not outweigh the inconvenience and risk associated with whole-house TOU rates.

EV-Only TOU Rate

Several of the New York IOU residential EV tariff proposals—including those of Con Edison, O&R, NYSEG, and RG&E—include the option for customers to charge EVs under a separately metered TOU rate, rather than under the whole-house TOU rate. However, separately metered customers would likely have to pay a full extra customer charge on top of their standard service customer charge. In exchange, these customers would not have to worry about managing their regular household appliance load in accordance with TOU periods.

Figure 16 shows that customers receive fewer fuel cost savings from switching to a separately metered TOU rate, as their higher total customer charge offsets the savings associated with a lower off-peak energy charge.[84] In fact, we estimate that typical separately metered EV customers would incur increased fuel costs in the service territories of every utility other than Con Edison. Customers of O&R could incur additional EV fuel costs of $250 by switching to the separate-meter TOU rate.

Figure 16. EV-only TOU rate annual fuel cost savings relative to standard rate



Source: Synapse Energy Economics analysis.

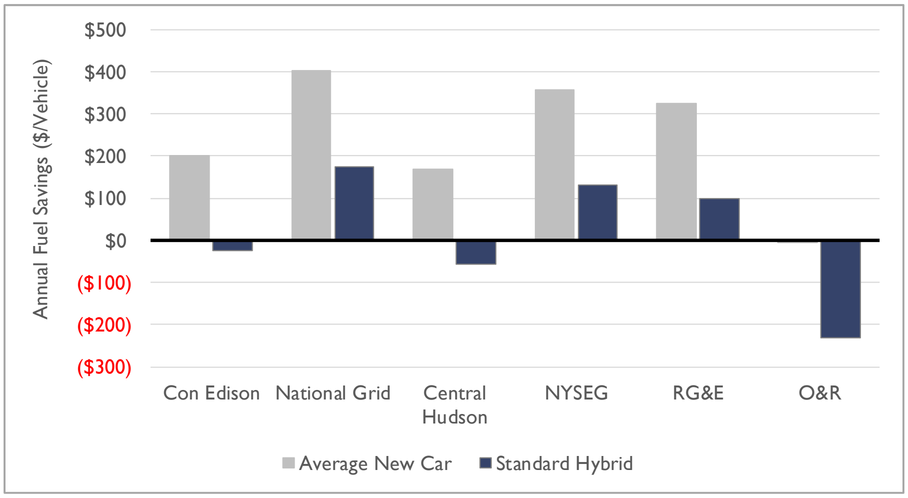
Results: EV Fuel Cost Savings Relative to ICEs

We find that the fuel cost savings provided by EVs on the proposed TOU rates relative to ICEs also vary greatly depending on the utility and the ICE in question. Figure 17 presents our calculated fuel cost savings for each utility for a typical 100-mile BEV on a whole-house TOU rate relative to two alternative types of ICEs: a typical new car with an efficiency of 38 mpg, and a standard hybrid with an efficiency of 55 mpg.[85]

[84] Although National Grid and Central Hudson did not specifically propose to allow EV customers to separately meter their EV loads, for the purposes of a comparative analysis we assumed that this would be allowed. The changes in fuel cost savings from Figure 15 to Figure 16 for National Grid and Central Hudson are due to the additional customer charge that we assume these customers would be required to pay in order for the EV to be metered separately.

[85] U.S. EIA. AEO 2018 Table 41. https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_41.xlsx . Standard hybrids do not draw electricity from an external source, and therefore must rely at least in part on gasoline during their standard operation. A Toyota Prius is one of the more common examples of a standard hybrid vehicle.

Figure 17. Annual fuel cost savings of 100-mile BEV on whole-house TOU rate relative to alternative ICE types



Source: Synapse Energy Economics analysis.

In nearly all utility service territories, an EV operating under the utility-proposed whole-house TOU rate would generate positive fuel cost savings relative to a typical new gasoline-powered vehicle. The savings provided by a new EV relative to a typical new ICE range up to more than $400 per year for a National Grid customer, although they are essentially zero for O&R customers.

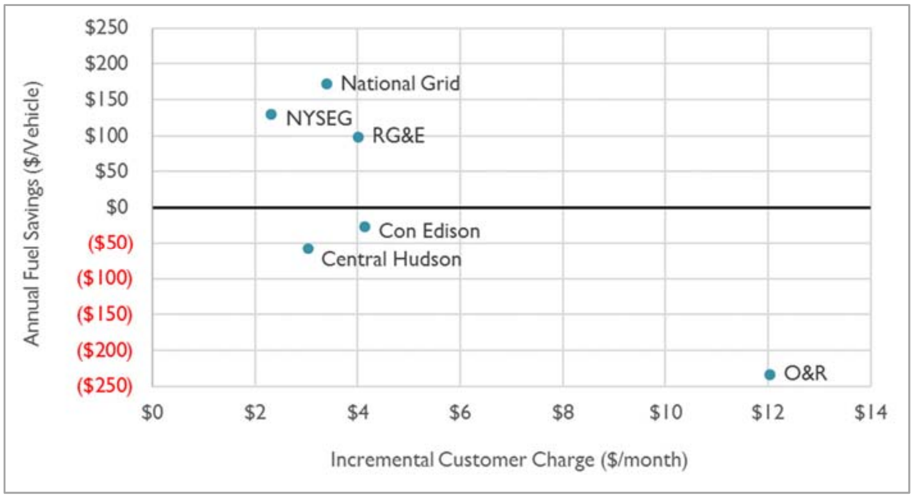
When compared to a standard hybrid vehicle, such as a Toyota Prius, EV fuel savings largely disappear. At three of the six IOUs, an EV customer would likely have higher fuel costs relative to a hybrid vehicle. This comparison is important, because customers considering purchasing an EV are likely to compare these vehicles to high-efficient ICE options, such as standard hybrids.

Once again, our analysis indicates that the EV TOU rates proposed by O&R and Central Hudson are the least favorable to EV customers. We estimate that a typical EV customer would incur increased annual fuel costs of more than $200 relative to a standard hybrid in O&R's territory, and more than $50 in Central Hudson's territory. In contrast, EV TOU customers of National Grid and NYSEG would experience annual fuel cost savings of more than $130, even compared to a standard hybrid. We note that for cost-conscious vehicle purchasers, an EV's fuel cost savings would need to be sufficiently large to out-weigh the current higher up-front costs of an EV.

Role of Customer Charges

One of the main determinants of the variation in our fuel cost savings estimates across utilities appears to be the level of incremental customer charge incorporated in each whole-house TOU rate. All six utilities charge customers at least an additional two dollars per month in fixed customer charges when they switch from a standard rate to a whole-house TOU rate. For five of those utilities, the incremental customer charge is less than $4.50 per month. But for O&R, it is $12.00 per month, nearly three times greater than any other utility. This goes a long way toward explaining why our results indicate that O&R's EV TOU rate option offers the lowest fuel cost savings relative to both a standard residential rate and an ICE. Figure 18 provides evidence of a negative, if imperfect, relationship between the incremental customer charge and fuel cost savings of an EV on a utility's TOU rate relative to a standard hybrid vehicle.

Figure 18. Average annual fuel cost savings of 100-mile BEV relative to standard hybrid compared to customer charge increase



Source: Synapse Energy Economics analysis.

It is unclear to what extent higher customer charges faced by whole-house TOU customers are justified. Customer charges typically recover a variety of costs associated with serving a customer, such as billing and customer service costs, as well as the cost of the meter, final line transformer, and service drop. Some of these costs may be higher for a whole-house TOU customer than for a customer on standard rate, particularly if a more sophisticated meter is required for measuring hourly usage. However, most costs (such as the cost of the final line transformer and service drop) will not be higher. It is very unlikely that the large incremental customer charge incurred by O&R customers is justifiable on cost causation grounds, much less on grounds of encouraging adoption of TOU rates or purchase of EVs.

4.3. Additional Important EV Rate Design Characteristics

Besides overall rate design structure and impacts on fuel costs, there are several other design characteristics that can impact the effectiveness and efficiency of EV rates. We again find major differences among the New York IOU proposals across several of these characteristics. Below, we focus on the proposals' peak-to-off-peak price ratios, relationship to standard offer service rates, and alignment of TOU periods with system costs.

Ratio Between Peak and Off-Peak Rates

The ratio between peak and off-peak prices is a key determinant of the effectiveness of TOU rates at encouraging EV customers to charge during off-peak hours. A study of early-adoption EV customers in

SDG&E service territory found that a peak to off-peak price ratio of 6:1 results in about 10 percent more off-peak charging than a ratio of 2:1.[86]

Table 2 lists the ratios between peak and off-peak TOU delivery charges under the whole-house TOU rates proposed for residential EV customers by each of the IOUs. Con Edison and O&R each offer rates with ratios greater than 14:1 in the summer months, and greater than 5:1 in the winter months. In contrast, Central Hudson's rate has a ratio of only 1.2:1 throughout the year. Such a low ratio has two likely repercussions. First, it makes it less likely that customers who adopt the TOU rate will charge their EVs exclusively during off-peak periods. Second, it lessens the opportunity for EV customers to control and reduce their fuel expenses. This effect helps explain why our analysis finds that Central Hudson's proposal would result in such low (and sometimes negative) fuel cost savings for EV customers.

Table 2. Ratios between peak and off-peak TOU delivery charge

Utility	Summer	Winter
Con Edison	14.2	5.2
National Grid	6.5	6.5
Central Hudson	1.2	1.2
NYSEG	2.7	2.7
RG&E	2.7	2.7
O&R	15.5	5.6

Relationship to Standard Offer Service Rates

Another important distinction among the EV TOU rate offerings of the New York utilities is the extent to which those rates are linked with TOU energy supply rates. Since New York is a competitive retail access state, the IOUs do not provide energy supply services to all residential customers. However, they do provide standard offer service rates to customers who do not select a competitive supplier. These utilities therefore have the ability to offer TOU standard offer service rates to complement the delivery TOU rates that they are presenting as their residential EV tariffs.

It appears that all six IOUs already offer TOU standard offer service rates to complement their TOU delivery rate offerings. However, there is variation in the degree to which these standard offer service offerings contribute to strong differentials between the total energy charges faced by TOU customers during on-peak and off-peak periods. Con Edison offers rates that vary dramatically between peak

[86] Nexant. 2014. "Final Evaluation of SDG&E Plug-in Electric Vehicle TOU Pricing and Technology Study." Available at www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20&%20Tech%20Study.pdf.

summer hours and other times of the year, whereas the TOU standard offer service offerings of NYSEG and RG&E do not exhibit marked differences between peak and off-peak hours.

Given that customers ultimately perceive and pay a total per-kWh energy charge that incorporates both delivery and supply charges, it is important that both delivery and standard offer service TOU offerings contribute to an efficient price signal regarding the least-cost times to charge EVs. The difference in price ratios across the utilities for standard offer service prices may be due to variations in zonal wholesale market prices. However, it is worth reviewing the price differentials to ensure that the standard offer service prices are as efficient as possible.

TOU Periods

Another point of inconsistency across the New York IOUs is in their selection of on-peak and off-peak hours. All of the utilities apply their highest peak TOU rates to summer (June through September) weekdays between 2 p.m. and 7 p.m. Beyond that point of consistency, differences arise.

One notable inconsistency is in the seasonality of peak periods. O&R and Con Edison offer peak periods that are limited to just the summer months. These utilities apply a “semi-peak” rate in between the on-peak and off-peak rates to winter afternoon and evening hours. All other utilities apply the same price to all hours throughout the year.

The summer focus of O&R and Con Edison is likely rooted in the fact that New York has a summer-peaking electricity system. In each of the past three years, each of the top 100 annual peak system hours occurred between June and September.[87] However, the timing of peak periods should account for marginal energy costs as well as marginal system capacity costs. Though New York’s peak load events occur during the summer, its highest energy prices often occur during winter evenings. Figure 19 presents a heat map showing that the highest system energy prices in 2017 came during the months of December and January between 4 p.m. and 9 p.m.[88] Accounting for this pattern, it likely makes sense to apply peak periods to winter evenings, as most New York IOUs do.

[87] NYISO Market & Operational Data, Custom Reports: Real-Time Actual Load. http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp?report=rt_actual_load

[88] NYISO Market & Operational Data, Custom Reports: Day-Ahead Market LBMP – Zonal. http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp

Figure 19. 2017 average NYISO locational marginal prices

	Month											
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	$29	$24	$24	$18	$18	$18	$22	$20	$17	$17	$19	$32
2	$27	$22	$23	$17	$16	$16	$20	$18	$15	$15	$17	$30
3	$26	$21	$22	$16	$15	$15	$18	$16	$13	$14	$16	$28
4	$25	$21	$22	$16	$14	$14	$17	$15	$12	$13	$16	$28
5	$26	$21	$22	$16	$14	$13	$16	$15	$12	$13	$16	$29
6	$28	$23	$24	$17	$16	$14	$16	$16	$14	$15	$19	$33
7	$33	$27	$31	$23	$21	$17	$18	$17	$17	$22	$26	$42
8	$36	$29	$35	$26	$24	$20	$21	$19	$18	$24	$30	$45
9	$38	$29	$35	$30	$26	$22	$24	$22	$20	$23	$31	$46
10	$39	$30	$34	$31	$28	$25	$26	$24	$22	$25	$31	$47
11	$38	$29	$33	$30	$29	$26	$28	$26	$23	$25	$30	$47
12	$37	$29	$32	$30	$28	$28	$31	$28	$25	$26	$29	$44
13	$35	$27	$30	$28	$27	$30	$33	$29	$26	$25	$27	$41
14	$34	$26	$28	$27	$27	$31	$36	$31	$28	$25	$27	$39
15	$33	$26	$27	$26	$27	$32	$38	$33	$30	$26	$26	$39
16	$33	$26	$26	$25	$27	$34	$40	$35	$32	$26	$27	$40
17	$39	$28	$28	$26	$28	$35	$43	$36	$34	$28	$32	$51
18	$50	$36	$31	$28	$31	$36	$43	$36	$33	$30	$39	$66
19	$48	$39	$36	$30	$29	$32	$37	$31	$30	$34	$38	$62
20	$43	$35	$40	$34	$30	$30	$34	$29	$31	$34	$35	$56
21	$39	$31	$37	$36	$33	$29	$32	$28	$28	$28	$31	$50
22	$36	$28	$32	$28	$27	$27	$29	$26	$23	$24	$27	$44
23	$32	$26	$27	$22	$22	$22	$25	$22	$19	$20	$23	$38
24	$29	$24	$24	$19	$20	$19	$23	$20	$18	$18	$19	$34

The choice of peak hours within a season is another area of difference across the IOUs. Central Hudson's peak period is the narrowest of the utilities, running from 2 p.m. to 7 p.m. O&R's peak period is limited to summer hours between noon and 7 p.m. The peak periods of the other four IOUs are much longer, lasting from at least 8 a.m. through 11 p.m. Based on load and price data from the past three years, the longer peak periods appear to better capture higher-cost hours without stretching into the lowest-cost overnight hours.[89] Figure 19 indicates that Central Hudson's shorter peak period would miss both the winter morning peak and the end of the winter evening peak, which represent some of the highest-cost hours of the year. In addition, over the past three years the top 100 annual NYISO peak hours have included summer hours between 10 a.m. and 2 p.m., and between 7 p.m. and 9 p.m.

4.4. Metering

None of the New York IOUs have proposed a submetering option using an EVSE for their EV rates, nor have they explained why EVSE submetering was not proposed. Instead, all of the IOUs would require

[89] Of course, peak periods should not be so long as to produce brief off-peak periods that may limit fuel cost savings opportunities and lead to distribution peak clustering concerns. However, as long as the off-peak period remains at least eight hours in length, these concerns are likely to be minor.

traditional utility meters for customers who wish to enroll in an EV-only rate, with the exception of Con Edison's ongoing SmartCharge NY program (which uses the FleetCarma C2 device). The failure of the New York utilities to consider submetering options could dampen enrollment levels in the proposed EV TOU rates.

4.5. Reporting Metrics

Regardless of the rate designs ultimately implemented for EV customers, it will be important to use the lessons learned to improve rate design moving forward. To enable data-driven assessment of the effectiveness of each utility's rates, we propose that the utilities report additional data to the Commission and stakeholders. Ideally, such reporting would occur frequently enough to make mid-course corrections, if necessary. We recommend that the utilities file publicly available quarterly reports containing the following metrics and data (in spreadsheet format):

- Number of customers on whole-home versus EV-only rate
- Number of customers who opted to leave the TOU rate
- Aggregated customer load profiles, including the percentage of EV charging that occurred on-peak versus off-peak
- Monthly average energy (kWh) and peak demand (kW) associated with EVs
- Costs to integrate EVs into the grid, including the location of any distribution upgrades and the type of upgrade required
- TOU rate education and outreach activities undertaken by utilities, including relevant budgets
- Lessons learned and modifications made; for example, if low enrollments prompted a utility to seek an alternate marketing approach, this should be discussed.

4.6. Enrollment in TOU Rates

While the design of TOU rates is critical to ensuring their success, even the best-designed rates will suffer from low enrollment levels if customers are not well informed regarding the rate options and potential fuel savings, or if enrollment is time-consuming and difficult. Each of the New York IOUs currently has a residential TOU rate in place.[90] Enrollment in these rates has been exceedingly low: Only one IOU has seen more than 1 percent of its residential customers choosing the TOU rate, as shown in Table 3, below.

[90] Note, however, that there is no on-peak to off-peak distribution rate differential for NYSEG and RG&E.

Table 3. Residential enrollment in TOU rates currently in effect

Utility	Residential TOU Customers	Total Residential Customers	% TOU
National Grid	5,624	1,475,271	0.4%
Con Edison	1,720	2,896,029	0.1%
Central Hudson	1,000	266,061	0.4%
RG&E	1,273	334,750	0.4%
NYSEG	4,016	766,954	0.5%
O&R	3,399	198,331	1.7%

Sources: Con Edison AMI Metrics Report Appendix 18. April 30, 2018. Filed in NY PSC Docket 16-00253; Niagara Mohawk Rate Case Testimony of Electric Rate Design Panel. April 28, 2017. Book 20, Exhibit 1 (p. 77). NY PSC Case No. 17-E-0238; Central Hudson Cost of Service Exhibits. July 28, 2017. (p. 6). NY PSC Case No. 17-E-0459; RG&E Revenue Allocation, Rate Design, Economic Development, and Tariff Panel Testimony. May 20, 2015. (p. 73). NY PSC Case No. 15-E-0285; NYSEG Revenue Allocation, Rate Design, Economic Development, and Tariff Panel Testimony. May 20, 2015. (p. 61). NY PSC Case No. 15-E-0283; O&R Electric Rate Filing Exhibits. January 26, 2018. Volume 2 (p. 522). NY PSC Case No. 18-E-0067.

To encourage EV customers to enroll in a TOU rate, the IOUs must do more than simply establish the rate. They must actively encourage enrollment through a combination of education, outreach, and incentives. In addition, utility incentives, auto dealership incentives, and customer incentives should all be aligned. As described in Section 3.5, these activities may include setting up a web-based rate comparison tool and monetary incentives for enrollment in an EV rate (paid either to EV drivers or dealerships who help the customers enroll). In New York, utility incentives could be established through Earnings Adjustment Mechanisms that establish targets not only for customer adoption of EVs, but also for enrollment in an EV rate.

5. CONCLUSIONS AND RECOMMENDATIONS

Utilities have a unique opportunity to influence EV adoption and steer EV charging practices to benefit the grid and society. To attain these benefits, EV rates must be designed carefully and thoughtfully. Our evaluation of the New York utilities' recent proposals can be used to illustrate many of the rate design principles discussed throughout this report.

The New York utilities have taken an important step in the right direction by offering a whole-house TOU rate that would enable EV drivers to save money on fuel costs, while encouraging beneficial charging behavior. Several of the utilities have also opted to offer an EV-only rate, which provides a great option for customers who are hesitant to adopt a whole-house TOU rate. Further, all of the utilities offer a price guarantee, which reduces the risk to customers of signing up for a new rate.

However, most of the utilities' rate proposals require additional work to unlock their full potential. In many cases, the potential fuel cost savings are minimal, or even negative, relative to the standard rate. Further, the fuel cost savings relative to the cost of operating an efficient ICE (e.g., a hybrid) are generally also low or negative.

To achieve greenhouse gas emission reductions of 40 percent by 2030 and 80 percent by 2050, and to comply with Zero Emission Vehicle (ZEV) regulations that will require approximately 800,000 EVs in New York by 2025, the utilities' EV rate designs must be improved. We offer six recommendations that could commence today:

1) Utilities with low price differentials between on-peak and off-peak rates increase the price ratio to motivate off-peak charging and enable greater fuel savings;

2) Ensure that a customer who charges mostly off-peak achieves fuel savings relative to a customer who remains on a standard rate and charges only on-peak;

3) Reduce or eliminate the customer charge for second meters;

4) Explore submetering as a means to lower the cost for EV-only rates;

5) Evaluate whether the proposed rate will provide sufficient fuel savings to encourage customers to adopt EVs over high-efficiency ICE vehicles; and

6) Endeavor to maximize customer enrollment through education, outreach, and incentives.

Finally, we recommend that these actions on residential rate design be complemented by an analysis of commercial and industrial rates to determine whether modifications are warranted to support EV charging stations, fleet electrification, and workplace charging.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	**)**
Application of Duke Energy Progress,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-6

PUBLIC VERSION

EVGO FLEET AND TARIFF ANALYSIS

PHASE 1: CALIFORNIA

BY GARRETT FITZGERALD AND CHRIS NELDER

AUTHORS & ACKNOWLEDGMENTS

Authors

Garrett Fitzgerald, Chris Nelder

** Authors listed alphabetically. All authors are from Rocky Mountain Institute unless otherwise noted.*

Contacts

Chris Nelder (cnelder@rmi.org)

Garrett Fitzgerald (gfitzgerald@rmi.org)

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Image courtesy of EVgo

About Rocky Mountain Institute

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

EXECUTIVE SUMMARY

Public direct current fast chargers (DCFC) are anticipated to play an important role in accelerating electric vehicle (EV) adoption and mitigating transportation sector greenhouse gas (GHG) emissions. However, the high cost of utility demand charges is a significant barrier to the development of viable business models for public DCFC network operators.

With today's EV market penetration and current public DCFC utilization rates, demand charges can be responsible for over 90% of electricity costs, which are as high as $1.96/kWh at some locations during summer months.[i] This issue will be compounded by the deployment of next-generation fast-charging stations, which are designed with more than two 50 kW DCFC per site and with higher-power DCFC (150kW or higher).

As state legislators begin to craft legislation defining the role of utilities in deploying, owning and operating electric vehicle charging stations (EVSE) and other supporting infrastructure, it is critical that utility tariffs for EV charging support, rather than stifle, the shift to EVs. Utilities, their regulators, and EV charging station owners and operators must work together to provide all EV drivers—especially those without home and workplace charging options—access to reliable EV charging at a rate competitive with the gasoline equivalent cost of $0.29/kWh.[ii] Put another way, it should be possible for DCFC operators to sell power to end-users for $0.09/mile or less, while still operating a sustainable business.

This project analyzed data from every charging session in 2016 from all 230 of EVgo's DC fast charging stations in the state of California. From that data, we developed demand profiles for eight common types of site hosts, and analyzed the components of EVgo's costs based on the utility tariffs the charging stations were on.

We also created a workbook modeling tool that EVgo could use to test the effect that different tariffs would have on its network of charging stations within the territory of the three major California investor-owned utilities (IOUs): Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Pacific Gas & Electric (PG&E). To provide context for this modeling, we created four scenarios describing the possible future evolution of the EV and public charging markets. These scenarios were narrative in nature, and mainly served as conceptual guides to future cost modeling.

After modeling how different current and future tariffs affect the utility bills for each type of site where EVgo's DCFC are located, and how those bills might look under the four scenarios in the future, we developed a critique of the various tariffs and some recommendations for future EV-specific rate design efforts.

We concluded that, in order to promote a conducive business environment for public DCFC charging stations like EVgo's, tariffs should have the following characteristics:

- Time-varying volumetric rates, such as those proposed for SDG&E's Public Charging Grid Integration Rate (GIR). Ideally, these volumetric charges would recover all, or nearly all, of the cost of providing energy and system capacity. An adder can be used to recover excessive costs for distribution capacity, but only costs in excess of the cost of meeting the same level of usage at a uniform demand rate, and ideally such an adder would be something the customer can try to avoid. The highest-cost periods of the time-of-use (ToU) tariff should coincide with the periods of highest system demand (or congestion) to the maximum practical degree of granularity.
- Low fixed charges, which primarily reflect routine costs for things like maintenance and billing.

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[i] Based on summer rates at EVgo's lowest-utilization SDG&E Freedom Station, Las Americas (bill date of June 28, 2016),
[ii] Assumes 32 mpg, $3/gallon of gas, 0.32 kWh/mile

- The opportunity to earn credit for providing grid services, perhaps along the lines of a solar net-metering design.
- Rates that vary by location. "Locational marginal pricing" is conventionally a feature of wholesale electricity markets, reflecting the physical limits of the transmission system. But the concept could be borrowed for the purpose of siting charging depots, especially those that feature DCFC, in order to increase the efficiency of existing infrastructure and build new EV charging infrastructure at low cost. This could be done, for example, by offering low rates for DCFC installed in overbuilt and underutilized areas of the grid, particularly for "eHub" charging depots serving fleet and ridesharing vehicles.
- Limited or no demand charges. Where demand charges are deemed to be necessary, it is essential that they be designed only to recover location-specific costs of connection to the grid, not upstream costs of distribution circuits, transmission, or generation.

Our analysis shows that the new EV-specific tariffs proposed by SDG&E and SCE in their SB 350 Transportation Electrification applications would have far more stable and certain costs than the tariffs currently available in their territories, and would meet the objective of delivering public charging to end-users for less than $0.09/mile, in all four scenarios. This is primarily due to the lower or non-existent demand charges outlined in the new tariffs.

We show that reducing or eliminating demand charges for the commercial public DCFC market, as these new tariffs do, is consistent with good rate-design principles and helps California to achieve its social objectives. We suggest that recovering nearly all utility costs for generation, transmission, and distribution through volumetric rates is appropriate for tariffs that apply to public DCFC, and that recovering some portion of those costs from the general customer base would be justifiable because public DCFC provide a public good. Finally, we offer some additional suggestions for how EVgo might reduce the cost of operating its network, beyond switching tariffs.

FLEET AND TARIFF ANALYSIS

The purpose of this analysis was to determine the key factors that contribute to the electricity costs of EVgo's network of DCFC in California; what alternatives may be available to EVgo to reduce those costs; and to provide some guidance that may be useful for future rate design discussions.

Analysis of Current EVgo Fleet Usage in California

In the first part of the analysis, RMI and EVgo collaboratively explored the question: What are the demand profiles and energy consumption rates of EVgo's existing California DCFC network, and how do those profiles vary across different types of host sites?

EVgo provided data representing all fast charging sessions that occurred on its network of 230 DCFC in California in 2016. Key data included:

- Start time of session
- Length of session
- kWh consumed per session
- Host address and name

From this data, RMI created an hourly load profile for each host site. These profiles were used to identify usage trends and behaviors that are typical for particular types of host sites.

A sample monthly load profile is shown in Figure 1. It shows the energy sold per month (measured in kWh) and the monthly peak demand (measured in kW), for a DCFC located in Northern California. It demonstrates a large (up to 70%) variation in energy sales from month to month, and a relatively small (16%) variation in peak demand each month. This type of variation suggests a potentially unprofitable charging station, because the commercial electricity tariffs that these charging units are on will typically derive a significant portion of the bill from monthly demand charges (where the variation was small) while EVgo's revenue would primarily derive from the number of charging sessions and kWh consumed (where the variation was large).

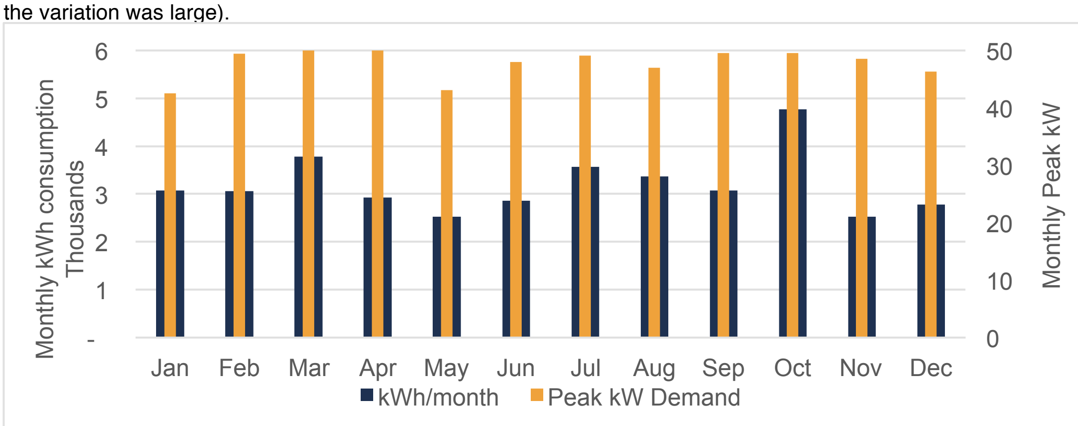

Figure 1: Monthly energy use and peak demand of an individual EVgo host site

A sample daily profile is shown in Figure 2. It shows the average utilization of an individual charger for each hour of the day. (Utilization is defined as the percentage of an hour that an EV is connected to the DCFC.) Hourly utilization is a useful way to understand when EV chargers are being used, and is of increasing importance as utilities are beginning to offer new EV-specific tariffs featuring ToU rates.

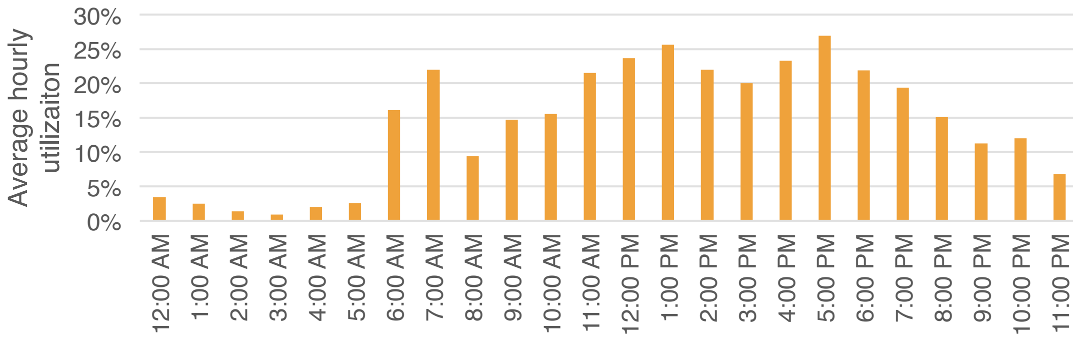

Figure 2: Hourly utilization rates of an individual EVgo host site

HOST CATEGORIZATION

We then grouped the various types of host sites into eight categories, based on the type of commercial activity associated with the host facility, and calculated a set of aggregate annual utilization and performance metrics for each category. This allowed us to identify utilization characteristics for each host type, and explore how monthly operational costs varied by host type. The summary results of this analysis, shown in Table 1, showed that charger utilization, average power, and energy consumption all vary significantly by the host type.

Host Category	***Peak kW***	***Avg kW***	***Avg kWh***	***Length (min)***	***# of sites***
Grocery	44	25	7.8	18	75
Mall	45	23	9.4	24	34
Other	44	27	8.2	18	11
Dealership	44	32	11.5	22	31
Retail	44	24	5.7	14	58
Gas Station	45	30	9.3	18	6
Gov't/School	41	26	8.3	19	13
Hotel	43	29	10.2	21	2

Table 1: Annual DCFC utilization and performance metrics by site host type

Exploring the relationships between the charging rate (kW), energy consumption (kWh), and charge duration offered some useful insights into how customers use these chargers. For example:

- Customers charging at retail locations tend to arrive with a higher state of charge (which causes a low average charging rate) AND are connected for a shorter duration (suggesting that they are just topping off their batteries, or charging opportunistically).

- Customers charging at car dealerships are arriving with a lower state of charge (which causes a higher average charging rate) AND are connected for a longer duration (suggesting that they have made a special trip to the dealership to get a full charge).

Exploring customer behavior as a function of host type was outside of the scope of this project. However, customer behavior and, more importantly, customer responsiveness to ToU price signals will be of critical importance in the design of both commercial DCFC tariffs and the pricing structures charging companies like EVgo offer to their customers. We explore these issues later in this report.

Regardless of the type of host, the DCFC utilization profile resembles the load profile of the California Independent System Operator (CAISO) system (the wholesale bulk power system in California), with low use in the early morning, increasing use throughout the day, and then a peak between 5 p.m. and 9 p.m. This is not surprising considering that customers typically use public DCFC opportunistically, when they're running errands and making other routine trips in the afternoon or after-work hours.

EV and EVSE Growth Scenarios

Before proceeding with modeling EVgo's current and future electricity costs, we created four scenarios describing how EV adoption and DCFC deployment might proceed in the future to provide context for the analysis. In the workbook model, these scenarios mainly serve as conceptual guides; they are not meant to be empirically derived.

ASSUMPTIONS

These assumptions apply to all four scenarios.

1. Time horizon: 10 years (2017–2027)
2. Incremental change only—no major technology breakthroughs, radical policy changes, etc.
3. Stable-to-slow-growth (3% or less compound annual growth rate[1]) for the U.S. economy
4. Industry standard DCFC power rate is 50 kW at start of scenario, 150 kW by 2020, and 300 kW by 2027. The average EV can accommodate the same rate of charging in those years.
5. Vehicle battery capacity ranges from 30–60 kWh in 2017, and 60–90 kWh from 2020 onward.[i]
6. Autonomous vehicles only become a factor after 2020 in all scenarios.

SCENARIOS

The main differences between the first three scenarios are the levels of EV adoption and corresponding distributed DCFC deployment. In the fourth scenario, autonomous vehicles become dominant rather quickly, and DCFC deployment is concentrated in charging hubs designed to serve fleets of shared vehicles, rather than being widely distributed.

Scenario 1: BAU, slow EV growth

A default business-as-usual (BAU) path in which current trends continue more or less unchanged. Personally owned vehicles remain dominant and EV penetration continues to follow today's moderate growth rates. Deployment of autonomous vehicles after 2020 is negligible, so those vehicles are not a factor in siting DCFC.

- EVs on the road in the US in 2027: 1.4 million, representing a compound annual growth rate (CAGR) of about 10%
- California falls short of its goal of having 1.5 million zero-emission vehicles (ZEVs) on the road by 2025. Instead it keeps its current market share of about half the U.S. EV fleet and achieves 700,000 EVs by 2027.
- Most charging is done at workplaces and homes using Level 1 or Level 2 chargers.

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[i] At 100 kWh, a vehicle would have a roughly 400 mi. range, which should be sufficient for most users' purposes. Therefore, we assume it would not be cost-effective to build vehicles with more than a 100 kWh capacity. Indeed, battery capacity may actually *decline* as DCFC chargers become more widely available, and it becomes less necessary to be able to drive long distances without recharging.

- There is a perceived need for DCFC services, but actual use of public DCFC is still quite limited at the end of the scenario period.
- Wireless charging does not get traction.
- Utility tariffs for EVs are still a very uneven landscape nationally, with California still the most progressive state, and most other states having no special EV tariffs.
- Vehicles are idle 95% of the time, making them available to provide demand response and other grid services.

Scenario 2: BAU, fast EV growth

BAU is still the main context and personally owned vehicles remain dominant, but EVs experience much faster growth. Deployment of autonomous vehicles after 2020 is negligible and they are not a factor in siting DCFC.

- EVs on the road in the US in 2027: 4.1 million (CAGRs accelerate from ~10% in 2017 to 35% in 2027)
- California meets its goal of having 1.5 million ZEVs on the road by 2025.
- DCFC for public access, workplaces, and heavily trafficked highway corridors are broadly available by 2027 and meet 30% of EV electricity consumption (kWh), but it's all still wired EVSE (not wireless). "Charging valets" are commonly used to move vehicles in and out of the charging bays, and their pay is regarded as a loss leader by the shopping malls, workplaces, and other sites where the chargers are located.
- Most utilities have offered EV-friendly charging tariffs by 2027, and the majority of chargers are on those tariffs.
- Some utilities buy grid services from EV aggregators and fleets using Level 1 and Level 2 chargers, but DCFC only sell demand response to utilities.

Scenario 3: Personal EVs gain real market share as wireless charging and autonomous EVs get traction

Personally owned vehicles remain dominant as EVs experience very fast growth. Autonomous vehicles become popular from 2020 onward and become a factor in siting DCFC.

- EVs on the road in the US in 2027: 10 million.
- California far exceeds its goal of having 1.5 million ZEVs on the road by 2025; it actually has 5.0 million by 2027.
- Over the scenario period, charging has begun to migrate to high-speed wireless induction chargers, which by 2027 are popping up everywhere: in parking spots, at stoplights, at workplaces, etc. Charging transactions are automated and billing is handled by a common payment processor (Visa, Stripe, a blockchain payment processor, or the like).
- Autonomous vehicles can go park themselves elsewhere when they're done charging to free up the charger for the next vehicle.
- Only about 20% of charging load is now met by Level 1 or Level 2 chargers at workplaces and residences, so their capacity to sell grid services to utilities is limited. The other 80% of charging load is met by ubiquitous DCFC, which can supply most vehicles with an 80% full charge in 15 minutes.
- Nearly all EVSE are on an EV-specific ToU tariff with local utilities.

Scenario 4: Fast autonomous EV growth leads to a MaaS future

EVs experience fast growth throughout the scenario period and autonomous vehicles gain a majority of market share by 2021, completely upending the normal vehicle market. By the end of the scenario period, autonomous vehicles are around 15% of all vehicles, as projected in Figure 3 below. Most of the autonomous vehicles are fleet vehicles and ride-hailing vehicles as mobility-as-a-service (MaaS) becomes commonplace. Personal vehicle ownership is in decline and most new vehicle sales are for fleet and ridesharing purposes.

- EVs on the road in the US in 2027: 41 million
- California has ~10 million ZEVs on the road by 2025, most of which are ride-sharing vehicles.

- Personal vehicle ownership falls sharply after 2020. By the end of the scenario period, sales of EVs have surpassed sales of internal-combustion engine (ICE) vehicles.
- DCFC are ubiquitous, meeting about 85% of EV electricity consumption. Many individual EV owners don't ever charge at home.
- Autonomous vehicles serve 30% of the total personal vehicle-miles-traveled (VMT) demand. Most of the autonomous EVs recharge at eHubs in a price-responsive manner when electricity costs are lowest.
- Distributed DCFC deployment may be topping out by the end of the scenario period, as hub-based charging of fleet vehicles becomes the dominant mode.

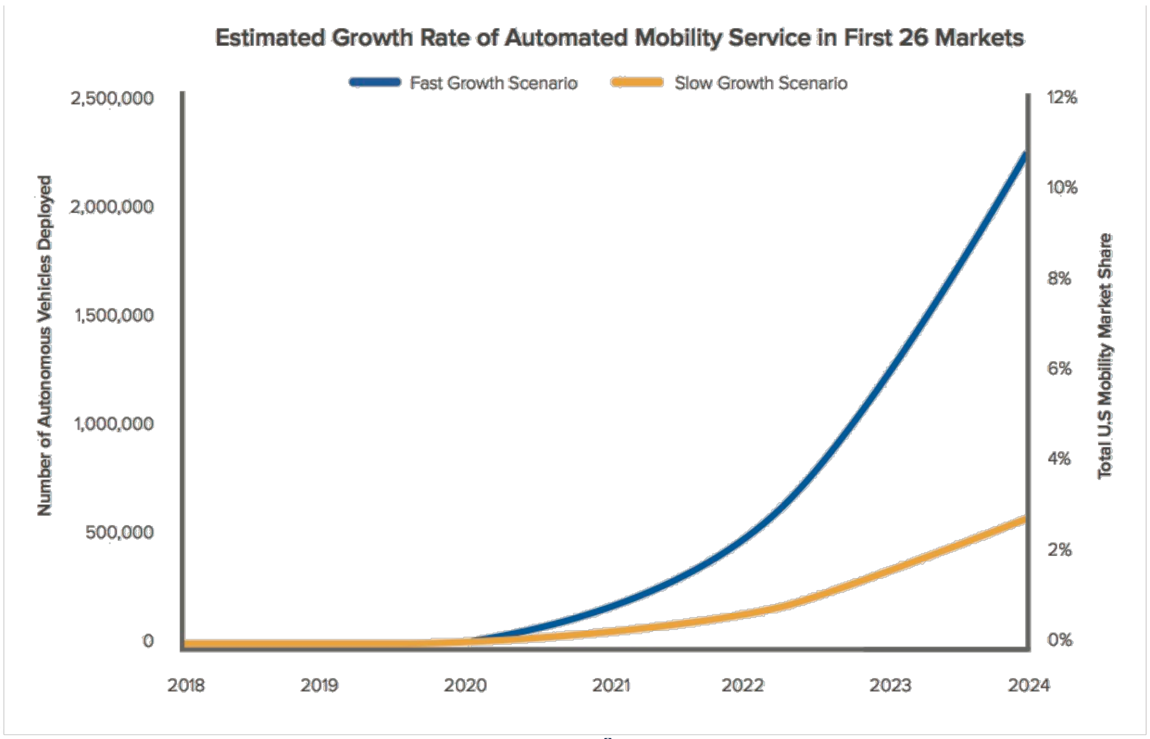

Figure 3 Mobility-as-a-service scenario. Source: RMI 2016, *Peak Car Ownership*[2]

Based on these scenario narratives, we created a simple model for EV deployment in California, shown in Figure 4. This EV model was integrated into the DCFC modeling workbook.

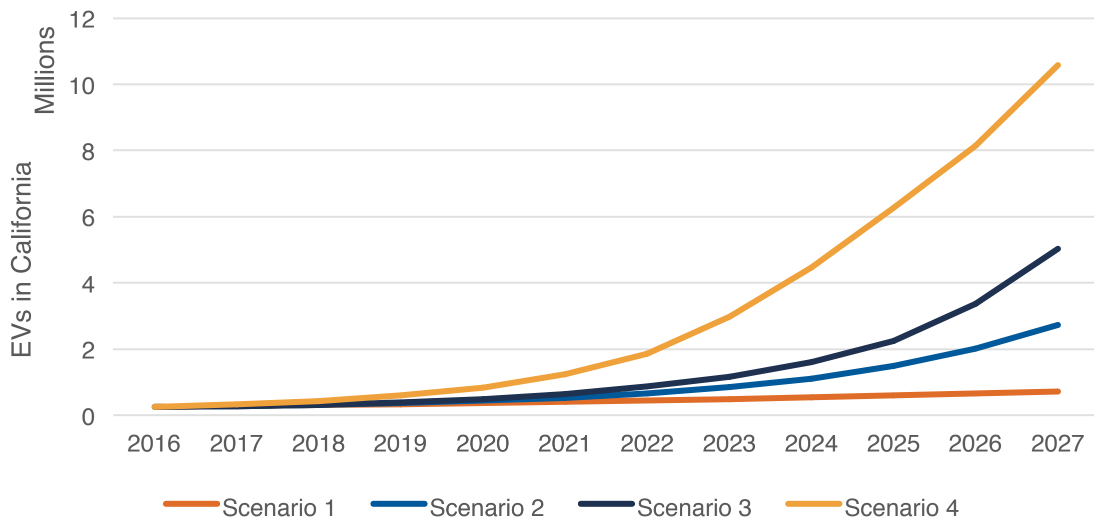

Figure 4: California EV deployment in the scenarios

HOW WE REPRESENTED THE SCENARIOS IN THE WORKBOOK MODEL

Although the scenarios were narrative in nature, and mainly served as conceptual guides to future cost modeling rather than being empirically represented, we did need to represent them numerically in the workbook to test how different tariffs would affect EVgo's fleet in the future.

The model is designed to determine the cost of operating DCFC under different tariffs and scenarios. The key cost determinants are:

- The number of kilowatt-hours consumed in a month
- When those kilowatt-hours are consumed (if under a ToU rate)
- The single hour of a month in which the highest demand occurred (if the tariff includes demand charges).

To determine those numbers for each scenario, we manually programmed the model with the following assumptions for three modeling years within the ten-year scenario period:

- The beginning (2017)
- Near the middle (2020, chosen because that year is often cited in policy targets and technical literature)
- The end (2027).

All scenarios began with the same data in 2017, derived from EVgo's actual data and other sources.

The following summary of the parameters used in the model is for illustrative purposes only; see the workbook for complete details.

Parameter	***Value in 2017***	***Value in 2027***
Average DCFC power (kW)	24	100–200
Peak power of a charging session (kW)	50	300
Vehicle battery capacity (kWh)	40	60–90
Charge to be filled per charging session (%)	30	30–50

Number of EVs in California	250,000	713k–10.6M
Annual VMT per vehicle (miles)	13,000	13,000–30,000
Efficiency (EV miles per kWh)	4	4
DCFC market share (% of total kWh charged with DCFC)	3	20–85
DCFC per 100 EVs in California	0.003	0.3–0.6

Table 2: Manually defined parameter values in the scenario model

From these initial values, we calculated:

Parameter	***Value in 2017***	***Value in 2027***
Average charging time (minutes)	30	8–19
Average charge per session (kWh)	12	27–63
Total kWh charging per month in CA (kWh)	77m	193m–6.6B
Number of public DCFC available	700	2k–63k
Average utilization per DCFC (%)	8	19–31

Table 3: Calculated parameter values in the scenario model

We then manually defined the shape of the load for the DCFC under each scenario in each of the three modeling years to notionally fit the narrative descriptions, by setting the percentage of total usage in each of the 24 hours of the day. Based on the load shape that emerged from this programming, we manually identified the hour of the day in which the peak monthly demand occurred.

Here is a brief description of our reasoning in selecting these load shape values.

2017

All scenarios are identical and represent a typical charger on the EVgo network today.

2020

Scenario 1 – Exactly the same load shape as in 2017, because utilities are slow to offer EV-specific ToU tariffs in Scenario 1, so drivers would not receive any particular price signals to charge differently than they did in 2017. However, overall usage increases slightly to reflect more EVs on the road.

Scenario 2 – DCFC utilization increases slightly across California. Overall utilization is slightly higher than in 2017 due to more EVs on the road and better siting and management by DCFC operators. Overall charging load is starting to shift towards midday in response to some ToU rates.

Scenario 3 – DCFC utilization is higher overall as some autonomous vehicles and charging valets increase the availability of DCFC. More of the load is shifted to midday than in Scenario 2 because more intensive charging management allows the vehicles to optimize their DCFC usage more closely to ToU rates with super off-peak periods in the midday.

Scenario 4 – The load shape is essentially the same as for Scenario 3 but with slightly higher overall utilization as fleet and ridesharing vehicles make up a greater part of the EV population. Total kWh consumed is substantially higher than in Scenario 3. A very significant increase in DCFC availability (from 0.003 to 0.7 per 100 vehicles) has kept utilization rates modest, but the DCFC fleet has grown by more than an order of magnitude.

2027

Scenario 1 – The load shape remains the same as in 2017, reflecting the lack of utility ToU rates under this business-as-usual scenario. The utilization rate is the same as in 2020 but the total kWh consumed has doubled due to more vehicles and chargers in the field.

Scenario 2 – The load shape is substantially similar to what it was in 2020, but with a bit more charging at midday as drivers take advantage of ToU rates to charge at their workplaces or during their lunch breaks.

Scenario 3 – The load shape is strongly shifted to midday in response to ToU rates, because autonomous vehicles can drive themselves to go find a charger when they are idle.

Scenario 4 – The load shape is highly optimized to charging at midday as fleet and ridesharing vehicles take advantage of super off-peak periods under ToU rates. However, charging dips slightly during times when demand for rides would be highest: during the morning and evening commutes, at lunchtime, and at the end of the evening as bar, restaurant, and entertainment patrons go home. Utilization rates are still modest but a vastly expanded DCFC fleet (roughly as many DCFC in 2027 as there are gasoline pumps in California today[3]) now serves 85% of total EV demand.

EV Rate Design

Having analyzed the use patterns of EVgo's DCFC fleet, developed an economic modeling workbook, and created scenarios to contextualize the economic analysis, we still needed to understand the current tariffs that the DCFC are under, and the new EV-specific tariffs that the California utilities have proposed.

In this part of the analysis, we begin with a very brief review of rate design theory, then move on to a discussion of the new proposed tariffs. Finally, we summarize the findings of our economic modeling of the various rates, and consider the likely implications for DCFC rate design in California in the future.

RATE DESIGN THEORY

EVs have only recently become a sufficiently significant type of load to warrant special tariffs, and so there is not as yet an established practice for EV rate design. However, in light of expected growth in EV ownership, unique charging attributes of EVs, and resulting effects on electricity demand, specific attention is now being paid to designing rates for EVs. Designing these well will be very important to realizing the goals of individual EV owners, fleet owners/operators, utilities, and society at large. Because it is about EVgo's DCFC fleet, this section focuses on rates for commercial DCFC operators, and leaves aside rates for residential customers charging EVs.

To understand the contemporary thinking on tariff design for commercial DCFC, and the anticipated trajectory of EV-specific tariff design in California, we examined the Transportation Electrification Plans submitted by the three California IOUs in January 2017, pursuant to SB 350 and California Public Utility Commission (CPUC) ruling R.13-11-007, "Order Instituting Rulemaking to Consider Alternative-Fueled Vehicle Programs, Tariffs, and Policies."[4]

California has roughly one-half of the nation's EV fleet, the most aggressive policies and targets in the nation for EV and charging infrastructure deployment, and utility programs specifically designed around EV-grid integration. On account of these structural conditions and the state's history of leadership on environmental and vehicle regulations, California's approach to DCFC tariff design may emerge as the utility industry "best practice" that other states will emulate.

In its Transportation Electrification Application,[5] SDG&E reiterates the CPUC's ten Rate Design Principles, as follows:

Cost of Service	·	Rates should be based on marginal cost;
	·	Rates should be based on cost-causation principles;
	·	Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
	·	Incentives should be explicit and transparent;
	·	Rates should encourage economically efficient decision-making;
Affordable Electricity	·	Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
Conservation	·	Rates should encourage conservation and energy efficiency;
	·	Rates should encourage reduction of both coincident and noncoincident peak demand;
Customer Acceptance	·	Rates should be stable and understandable and provide customer choice; and
	·	Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

Table 4: CPUC rate design principles

Of these principles, the ones pertaining to cost of service are the most relevant to tariffs for DCFC. How utilities incur specific costs, and then recover those costs through tariffs, is the heart of the question for tariffs that apply to DCFC. Conservation principles are also important because, as we will explain, DCFC-friendly tariffs would also try to reduce overall demand (especially demand coincident with system peaks or local distribution-area peaks).

SUMMARY ANALYSIS OF NEW TARIFFS PROPOSED BY SCE AND SDG&E

A brief summary of the new tariffs that were proposed by SCE and SDG&E in their Transportation Electrification Proposals and which would be applicable to EVgo's chargers follows. (PG&E did not submit any new EV-specific tariffs in its Transportation Electrification Plan, so its rates are not discussed here.)

SDG&E

The San Diego Gas & Electric (SDG&E) application[6] identifies "six priority review projects and one standard review residential charging program, all of which are designed to accelerate widespread transportation electrification in SDG&E's service territory, while maximizing grid efficiency with proper rate design." Of these projects, two have tariffs that could conceivably apply to EVgo's DCFC network:

- A Commercial Grid Integration Rate (GIR) applicable to the Fleet Delivery Services project, in which charging infrastructure will be installed at six locations to be used by electric fleet and delivery vehicles, such as those operated by UPS. This project would encourage charging at times that are beneficial to the grid and include a mix of Level 2 and DCFC charging stations. All of the chargers would be owned and operated by SDG&E.[7]
- A Public Charging GIR, applicable to participants in the Green Taxi/Shuttle/Rideshare project, which includes charging infrastructure, vehicle incentives, and a tariff aimed at the taxi, ridesharing, and shuttle bus market. This project would support up to four EV taxis, four electric shuttles and 50 transportation network company

(rideshare) EVs by deploying up to five grid-integrated charging facilities (one DCFC and two Level 2 EVSE each). All of the chargers would be owned and operated by SDG&E.[8]

To understand the underlying theory of rate design and cost recovery, it is worth examining SDG&E's explanation about why it has constructed these new tariffs the way it has.

SDG&E identifies the following objectives for its proposed tariffs:

1. To encourage economically efficient decision-making;
2. To encourage reduction of both coincident and noncoincident peak demand;
3. To provide a rate design that encourages cost-effective grid integrated charging solutions for EV customers;
4. To avoid cross-subsidies;
5. To base rates on cost causation; and
6. To examine alternative rate design.

SDG&E notes that in order to satisfy these objectives and the CPUC rate design principles, tariffs must **send accurate price signals**, which are **based on marginal costs and cost-causation principles**. (We would also note that the CPUC principles equally encourage conservation, energy efficiency, and demand management.)

SDG&E proposes to require participants to take service on its alternative GIR rate structures based on these cost-causation principles in order to accurately reflect costs.

The following table maps the typical tariff components to their cost-recovery justifications and their roles in the proposed GIR tariffs.

Charge Component	***Cost Recovered by the Charge***	***Component in Proposed GIR Tariffs***
Fixed or monthly charge ($/month)	Routine costs of having an interconnected customer, such as meter reading and billing	**Grid Integration Charge** ($/Month) Based on customer's max annual demand (kW), to recover all basic customer costs and 80% of distribution-demand costs
Peak demand charge ($/peak kW)	Costs of maintaining **system capacity** sufficient to meet peak demand (independent of energy usage) in excess of the cost of meeting below-peak demand	**Dynamic Adder – Commodity** ($/kWh – Top 150 hours of **system peak**)[9] Based on **commodity** peak pricing, to recover 50% of generation capacity costs
Noncoincident demand charge ($/noncoincident kW)	Costs of maintaining **circuit capacity** sufficient to meet the combined demands of customers on the circuit (independent of energy usage) in excess of the cost of meeting the same level of usage at a uniform demand rate	**Dynamic Adder – Distribution** ($/kWh – Top 200 hours of **circuit peak**)[10] Based on **distribution** peak pricing, to recover 20% of distribution demand costs Plus: Grid Integration Charge ($/Month per max kW), to recover distribution capacity investment

Energy charge ($/kWh at time of use)	Costs of procuring energy at a given point in time, plus the costs of distribution that would be incurred if all usage were at a uniform rate of consumption	**Hourly Base Rate** ($/kWh) Based on a variety of generation and transmission costs

Table 5: SDG&E charges, cost-recovery intents, and tariff components

Commercial GIR tariff

To support the policy objective of vehicle electrification specifically, SDG&E proposes a declining four-year discount on the monthly Grid Integration Charge for the Commercial GIR tariff. The cost of the discount would be recovered from all customers.

Rates for the new Commercial GIR tariff would be as follows:

Charge type	***Amount***
Grid Integration Charge[11]	Based on kW of maximum annual demand, with a declining discount over the first four years. When the discount expires in year five, EVgo DCFC might incur: · $522.37/mo. for up to 20 kW · $882.55/mo. for 20–50 kW · $1,458.86/mo. for 50–100 kW · $2,539.41/mo. for 100–200 kW
Hourly Base Rate	$0.096/kWh + CAISO day-ahead hourly rate
Dynamic Adder – Commodity	$0.50535/kWh
Dynamic Adder – Distribution	$0.18656/kWh

Table 6: Illustrative commercial GIR tariff charges

PUBLIC CHARGING GIR TARIFF

Because there is no single dedicated customer for public chargers, there is no Grid Integration Charge. Instead, some distribution-related costs are recovered through the Hourly Base Rate.

Rates for the new Public Charging GIR tariff would be as follows:

Charge type	***Amount***
Grid Integration Charge	N/A
Hourly Base Rate	$0.13871/kWh + CAISO day ahead hourly rate
Dynamic Adder – Commodity	$0.50535/kWh
Dynamic Adder – Distribution	$0.18656/kWh

Table 7: Illustrative commercial GIR tariff charges

ANALYSIS OF SDG&E'S PROPOSED TARIFFS

Although the new rates proposed in SDG&E's Transportation Electrification application are specifically targeted to the select projects SDG&E is proposing, in which it would install, own, and operate the charging infrastructure, the application also states, "While SDG&E provides these rate proposals as part this TE Application, SDG&E proposes not to limit the applicability of the proposed GIR to participants of SDG&E's TE proposals, and instead proposes that they be made available to all customers."[12]

The Commercial GIR is evidently targeted to delivery trucks and other fleet vehicles that can recharge overnight at a central charging depot, so it does not seem to apply to EVgo's network. However, it's not obvious whether EVgo could own chargers that would be available to delivery vehicles and be eligible the Commercial GIR. If any of EVgo's charging stations were to be used primarily by delivery trucks or other fleet vehicles, this tariff would pose a challenge to business model viability due to its high fixed Grid Integration Charges (unless the charging stations had very high utilization rates).

Allocating distribution-related costs through the fixed Grid Integration Charge would make it impossible for EVSE operators like EVgo to avoid those charges by smart charging (to avoid adding loads to the system peaks). It applies a high fixed monthly cost to every charging station, irrespective of that station's utilization rate. Applying this tariff to EVgo's charging stations would be undesirable.

The Public Charging GIR is aimed at high mileage taxi, shuttles and transportation network company (rideshare) electric vehicles that travel high-use transportation corridors. It is certainly within reason to expect that these vehicles, particularly ones operated by ridesharing companies like Uber, may use EVgo's network of DCFC in equal measure to the ones proposed in the SDG&E project. Other than ownership, there does not appear to be any qualitative difference between the public chargers in SDG&E's proposed Green Taxi/Shuttle/Rideshare project and the ones owned and operated by EVgo.

If EVgo's network of charging stations were to be considered eligible for the Public Charging GIR, it could be a good option for EVgo. As SDG&E explains, the Public Charging GIR does not apply the fixed Grid Integration Charges because there is no single dedicated customer for public chargers. Instead, it recovers a share of the distribution-related costs through the Hourly Base Rate. In theory, EVgo chargers on the Public Charging GIR could not only shift charging to low-cost, off-peak hours by various means, but also pass on peak CAISO pricing to customers who use the charging stations through visual price displays.

On an energy-only basis, the wholesale power supply cost of operating an EVgo charger on the Public Charging GIR might work out to around $0.048 per mile of charge. Whereas a consumer driving an ICE vehicle equivalent to a Nissan LEAF might expect to pay on the order of $0.094 per mile to refuel with gasoline. To a first approximation, then, on the Public Charging GIR, EVgo might have nearly a 100% margin to work with between its cost of utility service and the consumer's ICE refueling cost.[13] EVgo could use that margin to offset its site costs and equipment costs.

However, the "dynamic adders" (a form of Critical Peak Pricing charge) on the Public Charging GIR could amount to a worst-case annual cost of nearly $5,000 per year per charger. If EVgo could avoid or reduce its demand during the top 150 system hours and 200 circuit hours per year, for example by employing a stationary battery system to supply the power during those hours, or by throttling the chargers during those hours, or by raising its retail prices during those hours, or by some other means, those charges could be avoided and the tariff would be quite desirable. Since the peak hours that incur the dynamic adder fees are posted a day in advance, it should be practical for EVgo to pass along those costs to customers for charging during those hours.

If the worst-case dynamic adder costs were incurred, the effect on final cost would vary depending on several factors. For example: If they were amortized across the entire year, it would add $414 per month in costs. Assuming an average of 10 kWh of charge per session, that would affect the cost of the charger as shown in the following table.

Charging sessions per month	*Final wholesale cost to EVgo*
300	$0.092
600	$0.070
900	$0.063

Table 8: Estimated cost/mile scenarios under SDG&E Public Charging GIR

Even under the worst-case scenario and 300 sessions per month, the Public Charging GIR appears to be a more attractive option than the tariffs that typically apply to the class of Medium/Large Commercial & Industrial ("M/L C&I") Customers who have monthly demand peaks over 20 kW. Under the AL-ToU Commercial rate, EVgo's charging stations incur very high demand charges, which are used to recover distribution costs, transmission costs, and commodity costs. As a result, EVgo's stations under SDG&E's AL-ToU tariff are the costliest of all of its stations in California, regardless of utilization rate.

SCE

Southern California Edison (SCE), in its Transportation Electrification Plan, proposes three new, optional commercial tariffs for EVs, in addition to maintaining its existing ToU-EV-3 and ToU-EV-4 tariffs. Both the old and the new EV-specific tariffs are available for modeling and comparison in the modeling tool workbook deliverable.

All of the new rates are based on a revised ToU schedule that "will offer more accurate price signals to reflect system grid conditions, consistent with the Commission's recent guidance in this area." This ToU schedule, shown below, has the lowest-cost off-peak periods in the middle of the day, when Southern California's solar systems are producing power. This is nearly the inverse of a more traditional ToU schedule, and reflects the changing nature of the grid. (Before solar became a major midday power source in California, the most expensive "peak" pricing on a ToU schedule was always in the middle of the day, when demand was highest. Now Southern California frequently has enough solar power to drive prices to their lowest levels in the midday, making it the "super-off peak" period in the winter months, and the "off peak" period in the summer months of the proposed new ToU schedule.)

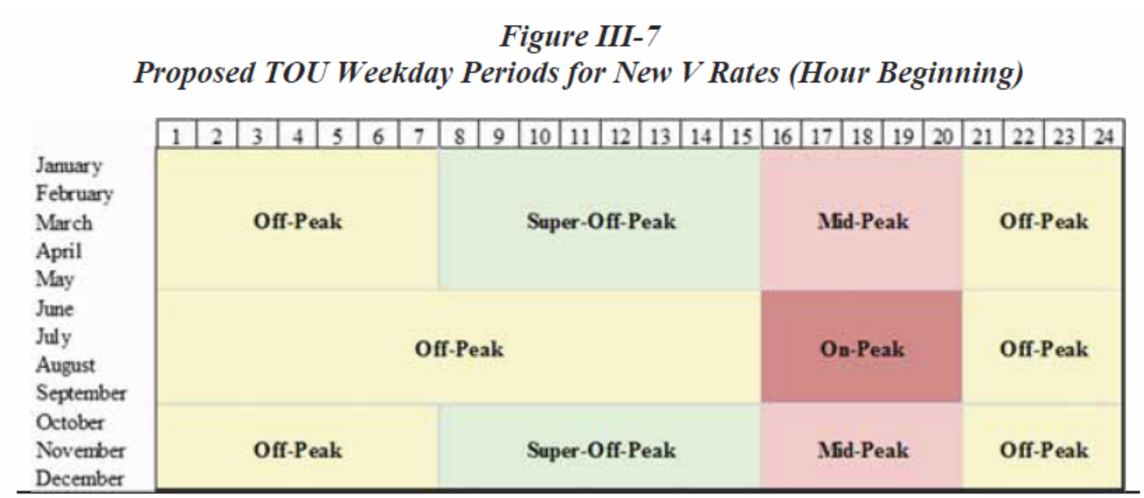

Figure 5: SCE's proposed ToU schedule for new EV tariffs. Source: Southern California Edison[14]

ANALYSIS OF SCE'S PROPOSED TARIFFS

Of the three new tariffs, the ToU-EV-8 tariff seems most likely to apply to EVgo, as it applies to customers with a monthly maximum demand between 21 and 500 kW.

SCE describes the benefits of the new EV tariffs as: "(a) reduced distribution-related demand charges relative to the current EV and non-EV rates; (b) attractive volumetric rates during daytime super-off-peak periods and overnight; and (c) lower summer season charges to mitigate seasonal bill volatility."

Importantly, to promote EV adoption, the new EV tariffs will suspend monthly demand charges during a five-year introductory period, after which SCE will phase in demand charges for a five-year intermediate period. During this intermediate period, the demand charges would collect an increasing share of distribution capacity-related costs, up to 60%, while the remaining 40% of distribution capacity costs will be collected via TOU energy charges. As the demand charges increase, the energy charges will decrease. Beginning in the eleventh year, the demand charges will be collecting 60% of distribution capacity costs and 100% of transmission capacity costs, and will have climbed to their full level, but SCE claims that the demand charges will "still be lower than what new EV customers would pay on their otherwise applicable (non-EV) commercial rates today."

The way demand charges are calculated would also change. Under its existing EV tariffs, "time-related demand charges" (TRD) are assessed on a time-of-use basis during the on- and mid-peak periods in a month. Under the new tariffs, "facilities-related demand charges" (FRD) would be calculated based on the maximum demand in a month, irrespective of its coincidence with the system peak. This change would make it more difficult for EVgo to pass on its time-varying costs to its charging station customers, or to reduce demand charges by encouraging customers to charge at times when grid power costs are lower. It also seems to contradict the intention of the demand charges, which is to recover SCE's capacity-related delivery costs.

The anticipated annual average bills for a medium-duty load (21 kW – 500 kW) under the proposed ToU-EV-8 tariff would be significantly lower than the current tariff alternatives for the first 10 years, but then approach the anticipated cost of being on the ToU-EV-4 tariff, as shown in SCE's table below.

Current ToU-GS-3	***Current ToU-EV-4***	***Future ToU-GS-3***	***Introductory New ToU-EV-8 Rate***	***Proposed Final ToU-EV-8 (Year 11)***
$93,208	$82,040	$89,997	$63,343	$75,995

Table 9: Anticipated annual average bills under various SCE EV tariffs

Analysis of current EVgo fleet electricity costs in California

With all of the components of the analysis now in place, our next step was to proceed to understanding the cost of current and future tariffs on EVgo's fleet, and develop some recommendations.

COST STRUCTURE OF CURRENT CALIFORNIA EVSE FLEET UNDER CURRENT RATES

To understand how EVgo's DCFC incur electricity costs, we developed a flexible Excel-based economic model to calculate the cost of operating the DCFC at each host type under various utility tariffs.

We modeled the typical daily load profiles for each host type and the actual utilization rates of the DCFC under several tariffs, including four tariffs the DCFC are on currently in each utility service territory, and the two new tariffs proposed by SCE and SDG&E.

Table 10 shows an illustrative total monthly electricity bill that a typical site with two DCFC would incur at each host type under these rates.

Category	*Host Type A*	*Host Type B*	*Host Type C*	*Host Type D*
Utilization	*15%*	*8%*	*8%*	*4%*
***SCE ToU EV 4** (actual)*	$1,933	$1,817	$1,762	$1,682
***SCE ToU EV 8** (proposed)*	$808	$648	$569	$461
***SDG&E AL-ToU Commercial** (actual)*	$3,313	$3,219	$3,178	$3,114
***SDG&E Public Charging GIR** (proposed)*	$501	$329	$255	$138
***PGE A-6 ToU** (actual)*	$484	$322	$260	$150
***PG&E A-10** (actual)*	$1,318	$1,197	$1,147	$1,065

Table 10: Monthly utility bill by rate and host type

This analysis demonstrated that tariffs with high demand charges and low energy charges (EV 4 and AL-ToU) show minimal variation in the total bill across a wide range of DCFC utilization, while tariffs with smaller or no demand charges show a much wider range in total electricity bill.

It also demonstrated that DCFC with identical load profiles may incur widely varying utility bills, depending on the tariff. For example, operating a DCFC at a Host Type D with an average utilization of only 4% would cost EVgo $150 per month on the PGE A-6 ToU rate, but would cost $3,114 on the SDG&E AL-ToU rate—20 times more.

Both findings demonstrate the same point: that tariffs without demand charges more accurately reflect cost causation, whereas those with demand charges would be burdensome to any public DCFC, regardless of utilization. This is problematic because it is the very nature of underutilized or newly installed DCFC that the station can experience very low monthly kWh consumption and relatively high peak demand.

Table 11 shows the fraction of the total utility bill that demand charges make up under each tariff.

Tariff	*Host Type A*	*Host Type B*	*Host Type C*	*Host Type D*
***SCE ToU EV 4** (actual)*	70%	75%	77%	81%
***SCE ToU EV 8** (proposed)*	0	0	0	0
***SDG&E AL-ToU Commercial** (actual)*	88%	91%	92%	94%
***SDG&E Public Charging GIR** (proposed)*	0	0	0	0
***PGE A-6 ToU with Option R** (actual)*	0	0	0	0
***PG&E A-10** (actual)*	67%	73%	76%	81%

Table 11: Demand charge bill fraction under various rates

COST STRUCTURE OF CURRENT DCFC OPERATION IN CALIFORNIA UNDER ALTERNATIVE/PROPOSED EV RATES

Using the economic model and applying actual utilization data[i] of a DCFC deployed in California, we compared how the cost of operation could change if the proposed EV tariffs are adopted and applied to EVgo's DCFC network. Table 12 and

[i] Hourly utilization profile of a typical grocery host site with a monthly kWh consumption of 2,764 kWh and a monthly peak demand of 88 kW

Table 13 show the component costs of SCE and SDG&E utility bills for the current and proposed EV tariffs. In both cases, the total bill would be drastically reduced (by between 50% and 80%) under the new proposed tariffs, primarily because SCE proposes waiving demand charges for the first five years of its tariff, and SDG&E proposes to waive the grid integration charge for its public chargers. Eleven years after its introduction, when demand charges are fully incorporated into the SCE EV-8 tariff and energy costs are adjusted downward, the total bill is still 25% lower than today's TOU EV-4 rate.

SCE	***Fixed***	***Energy***	***Demand***	***Total***
TOU EV4	$220	$278	$1,362	$1,938
TOU EV 8 without demand charges	$330	$478	$0	$808
TOU EV 8 with demand charges in year 11	$330	$368	$792	$1,490

Table 12: Utility bill for existing and proposed SCE EV tariffs

SDG&E	***Fixed***	***Energy***	***Demand/Dynamic***	***Total***
AL-TOU	$116	$279	$2,545	$2,941
Public GIR	$0	$452	$115	$567

Table 13: Utility bill for existing and proposed SDG&E tariffs

POTENTIAL COST OF FUTURE FLEET UNDER VARIOUS RATES BY SCENARIO

Our final step was to explore how EVgo's electricity costs could evolve over the next decade under various rates for each scenario. The scenario analysis forecasts the total monthly bill for a site with two DCFC being billed under the three most common existing commercial rates (SDG&E AL-TOU, PG&E A-10, and SCE TOU EV-4) and two proposed EV-specific tariffs (SDG&E Public GIR and SCE TOU EV-8) offered by the IOUs. We forecast monthly electricity costs that EVgo's chargers would incur in 2017, 2020, and 2027 for each of the four scenarios.

Figure 6 shows how these tariffs compare under the scenario analysis, in terms of the average cost that EVgo would incur per mile of charge that they deliver to the end customer. This cost-per-mile metric is an appropriate basis for comparison because the utilization of the DCFC and the number of customers each one serves can vary so widely from scenario to scenario.

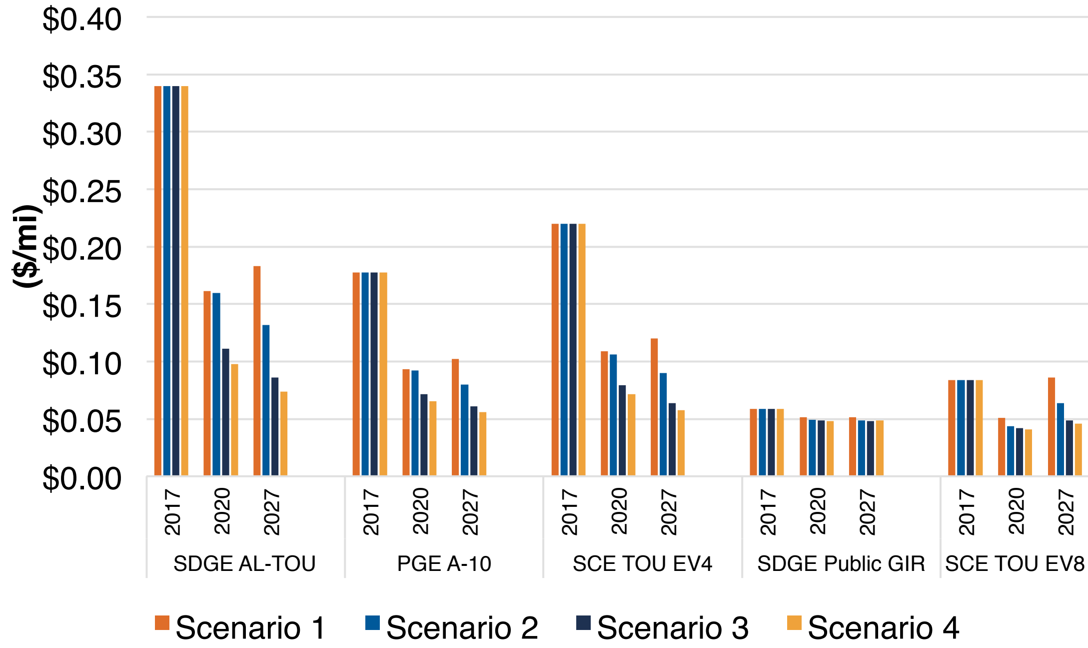

Figure 6: EVgo's cost per mile to deliver one mile of EV charge for existing and proposed EV tariffs

In all scenarios, the cost per mile of charge delivered to customers would decrease over time, primarily as a result of increased and optimized charger utilization. However, the costs would vary widely, from $0.05/mile to $0.35/mile, and would be highly dependent on the rate of EV and charging station deployment represented in the scenarios.

This analysis clearly shows that the new EV-specific tariffs proposed by SDG&E and SCE would have far more stable and certain costs, and would meet the objective of delivering public charging to end-users for less than $0.09/mile, in all four scenarios. This primarily owes to the lower or nonexistent demand charges outlined in the new tariffs. (*Nota bene*: The cost per mile under the SCE TOU-EV8 tariff declines from 2017 to 2020 because demand charges are waived during that period, then it increases again in 2027 as demand charges are phased in.)

Recommendations

It is clear from our analysis that demand charges, more than other rate components, are the primary reason why it is economically challenging to operate public DCFC profitably in California. As our analysis of chargers on the SDG&E AL-ToU Commercial rate clearly demonstrates, demand charges make up the vast majority of the bill, regardless of the charger's utilization. The fact that the proposed new EV-specific tariffs eliminate demand charges for a period of time, or for "Option R" charger installations, which also feature on-site renewable energy generators, indicates that the utilities understand this issue.

Switching to the proposed SDG&E and SCE tariffs that rely on dynamic adder charges rather than more conventional demand charges seems to solve many of the problems inherent in the existing tariffs. These new tariffs better align the utility costs with charges paid by EVgo, and could produce a fairer outcome in which it is possible for DCFC operators like EVgo to obtain a flatter, more predictable cost structure.

The question that remains is whether or not the new tariffs that the California IOUs have proposed can enable a profitable business for public DCFC charging companies, and whether there may be alternative approaches to rate design that would be more attractive.

PUBLIC DCFC RATE DESIGN THEORY/BEST PRACTICES

For a good guide to rate design theory in general, we recommend *Smart Rate Design for a Smart Future*.[15] It contains a good deal of material that may be useful to EVgo. But here are some condensed thoughts about tariffs for public DCFC like EVgo's in particular.

In theory, demand charges are assessed in such a way as to reflect the actual incremental capacity costs that the distribution utility incurs at peak times of the day, over and above the cost of capacity to serve off-peak demand. In practice, however, the structure of a tariff, including demand charges, often reflects other utility and social priorities as well, and the way that costs are recovered from various customer classes is not always consistent or reflective of cost causation.[16]

Traditional demand charges for small-to-medium commercial customers were never designed for a business like EVgo's, which has little control over when customers use its chargers, and which sees widely varying utilization rates across a heterogeneous network of chargers in widely varying locations and site types. In short, EVgo's network of chargers looks and behaves nothing like a large commercial or industrial facility, but it's being billed as if each location is a separate commercial facility.

The CPUC decision of December 2014 on a rate design proposal to include an Option R tariff in PG&E territory supports this reasoning. That case concerned how demand charges were used to recover peak-related capacity costs for solar customers, but the reasoning should apply equally to DCFC loads, which are also sporadic-use customers with a great deal of diversity. As the CPUC's decision argued:

> The first line of argument is that the collection of coincident peak related capacity costs on the basis of customers' highest single intervals of demand does not reflect the diversity benefit of multiple customers' solar output, and net loads on PG&E's system, changing by different amounts at different times….Stated differently, total coincident demand will never equal the sum of each customer's highest recorded demand during a given time period because of the variability of millions of customers' demands.[17]

It is also true that the local infrastructure needed to serve DCFC, particularly dense groups of chargers in an "eHub" configuration as imagined in Scenario 4, would be non-trivial and location-specific, and so would meet the criteria for recovery on a customer-specific basis. Customer-specific charges for customer-specific costs to connect to the grid can cover this local transformer and service line cost. But this cost recovery should not reach upstream of the immediate distribution connection to the broader distribution circuit costs (substation, transmission, and generation), all of which would be more equitably recovered on a ToU energy basis so that shared-capacity customers share costs, and continuous-capacity customers are not subsidized.

Although utilities may argue that high demand charges, adders, and fixed charges based on maximum demand, like SDG&E's Grid Integration Charge and SCE's TRD, are justified methods of recovering the costs of capacity investments, these approaches also allow off-peak loads to free-ride on the system capacity paid for by on-peak users. If total system demand were uniform across all hours, and there were thus no "peak" to trigger demand charges, there would still be extensive generation, transmission, and distribution capacity costs to be paid by all customers. Therefore, it's reasonable to argue that demand-based approaches amount to a shifting of system capacity costs onto customers with peaky demand profiles, and put an undue cost burden on those who may happen to have very brief and occasional demand spikes, like DCFC owners. To avoid such a cost-shift, system capacity costs should be recovered via energy sales, not separate demand-based charges. By this rubric, SDG&E's recovery of a high percentage of distribution capacity costs through the Grid Integration Charge, and SCE's recovery of transmission costs through its TRD, would be considered regressive approaches and would be discouraged. Those costs should be primarily recovered through ToU energy rates.

For tariffs that apply to public DCFC, demand charges for distribution circuit and upstream costs should be deemphasized—or better, eliminated. If demand charges must be a feature of tariffs for EVs, then those charges should be time varying and reflect actual system costs at a given time, in keeping with the principle of sending accurate price signals based on marginal costs. That way, if customers like EVgo are able to reduce their demands on the system's transmission and distribution capacity by charging vehicles at times when there is spare grid capacity, they should be able to reduce their costs for making that effort. Likewise, customer-specific demand costs, such as the transformer and service drop, can be recovered via a fixed fee like a grid integration charge, but the circuit costs should not; those should be recovered in ToU energy charges to assure that sporadic-demand customers who can share capacity get the cost-saving benefits of that sharing.

Beyond such fine points of rate design theory, it may make sense to allocate the cost of EV infrastructure more broadly across the entire customer base, because promoting EV adoption is a societal goal that California has explicitly established, and public DCFC deliver a public good. This is what SDG&E proposes to do for the "discount" on the monthly grid integration charge component of its Commercial GIR tariff. Low-income discounts, renewable energy incentives, and spreading the costs of providing full system reliability and meeting peak demand across the customer base are other examples of how some portion of actual costs are routinely socialized rather than being recovered entirely through a specific tariff. As the authors of *Smart Rate Design for a Smart Future* put it: "Regulators will need to determine if the public benefit of providing an infant-industry subsidy to EV charging is consistent with the public interest."[18]

Considering that owning and refueling an EV is already cheaper than owning and refueling a conventional ICE vehicle in many cases, and seems destined to only become more so, the continued advance of EVs against the existing ICE regime should be a relatively uncontroversial assumption. If we assume that EVs will continue to gain market share on their way to a near-total eclipse of the existing ICE vehicle regime—particularly if the future belongs to ride-sharing services provided by autonomous electric vehicles as imagined in Scenario 4—then socializing some part of the costs of building universally-available charging infrastructure might be justified.

Further, demand charges were invented in an era when a consuming commercial or industrial facility was only ever just that—a consumer. As RMI elucidated in its 2016 report, *Electric Vehicles as Distributed Energy Resources*,[19] and as both SDG&E and SCE have acknowledged and piloted to various degrees, what we should be aiming for is a future in which EVSE doing "smart charging" can supply a variety of services back to the grid, in addition to consuming energy from the grid.

Accordingly, best-practice rate design for EVs would feature not only time-varying tariffs that reflect the actual cost of energy provisioning and delivery at a given time (and eventually, place), but also the ability of EVSE to *reduce* the need for investments in distribution capacity by providing services like demand response, as well as the need to invest in capacity to supply those same EVSE. However, as currently conceived, demand charges act more like a calculator that can only add.

In summary, to promote a conducive business environment for public DCFC charging stations like EVgo's, tariffs should have the following characteristics:

- Time-varying volumetric rates, such as those proposed for SDG&E's Public Charging GIR. Ideally, these volumetric charges would recover all, or nearly all, of the cost of providing energy and system capacity. An adder can be used to recover excessive costs for distribution capacity, but only costs in excess of the cost of meeting the same level of usage at a uniform demand rate, and ideally would be something the customer could try to avoid. The highest-cost periods of the ToU tariff should coincide with the periods of highest system demand (or congestion) to the maximum practical degree of granularity.

- Low fixed charges, which primarily reflect routine costs for things like maintenance and billing.
- The opportunity to earn credit for providing grid services, perhaps along the lines of a solar net-metering design.
- Rates that vary by location. "Locational marginal pricing" is conventionally a feature of wholesale electricity markets, reflecting the physical limits of the transmission system. But the concept could be borrowed for the purpose of siting charging depots, especially those that feature DCFC, in order to increase the efficiency of existing infrastructure and build new EV charging infrastructure at low cost. This could be done, for example, by offering low rates for DCFC installed in overbuilt and underutilized areas of the grid, particularly for "eHub" charging depots serving fleet and ridesharing vehicles
- Limited or no demand charges. Where demand charges are deemed to be necessary, it is essential that they be designed only to recover location-specific costs of connection to the grid, not upstream costs of distribution circuits, transmission, or generation.

A SOCIAL OBJECTIVE APPROACH

The preceding discussion attempted to use the framework of traditional rate-design theory and existing rate proposals to identify a viable path for public fast-charging companies like EVgo. But perhaps a more unconventional approach is worth considering.

To begin with, we should recognize that the societal objective should be to create a business opportunity for EV charging companies like EVgo to earn a reasonable profit by providing a valuable service and maintaining universally available charging equipment in serviceable condition. That is not currently the case.

To achieve this objective directly, we could design a tariff by working down from a cost that will be attractive to consumers, rather than by building up from the cost basis of the utilities. Based on our simple calculations above, this approach might target a cost to the EV end-user of no more than nine cents per mile, in order to maintain the cost advantage of EVs over ICE vehicles. From that nine-cent-per-mile target, one could deduct a reasonable profit margin for the charging companies, and then set the result as the cost ceiling for a tariff that applies to public DCFC owners. Whatever missing revenue there may be between the revenue potential of that tariff and what is deemed to be the actual cost of service could be recovered from the general customer base on a cost (not cost-plus) basis only, to reflect the fact that there are numerous EV-to-grid value streams that remain to be recognized in the tariffs, including the nebulous, yet real, value of enabling greater renewable energy penetration.

Should the state of the art in EV rate design evolve in the future, and make it possible to quantify and compensate the various value streams in the EV-grid interaction more discretely, a more sophisticated approach to EV tariffs could be devised. But at the present time, recognizing the great importance of California's societal goals embodied in the hopes for much faster EV adoption, the emerging nature of the underlying EV and telematics technologies, and the difficulty of the existing tariff regime for DCFC providers, a tariff along these lines can strike an appropriate balance between the theory and the practice of EV rate design, while supporting established policy objectives and design principles.

HOW TO MODERATE EVGO'S COSTS

If possible, the most straightforward option for EVgo to reduce its public DCFC costs would be to switch to the Public GIR tariff in SDG&E territory, and the TOU EV-8 tariff in SCE territory, as depicted in Figure 6. Switching to these tariffs could result in a bill reduction of up to 80% for DCFC in SDG&E territory, and between 25–50% for DCFC in SCE territory. Our modeling suggests that under these new tariffs, EVgo could potentially run those DCFC profitably while meeting the objective of delivering public charging to end-users for less than $0.09/mile. However, these tariffs are only proposed at this point, so whether switching to these tariffs is actually an option for EVgo is unknown at this time.

In the absence of tariff options for DCFC that substantially reduce or completely eliminate demand charges, the next best option might be for EVgo and other EVSE companies to adopt the concept of surge pricing and pass along the high demand charges and adders to their customers, where possible, to allow the utility's price signal to influence when and where electricity is used on the grid, as such charges are intended to do.

In SDG&E territory, it may be possible for EVgo to hedge against critical peak pricing events that trigger the dynamic adders of ToU rates by paying a fixed monthly Capacity Reservation Charge (CRC).[20] We did not model this option in this study, but it could be worth exploring with SDG&E.

It may also be possible for EVgo to get consolidated billing from the utilities based on the loads of all charging stations on the utility's system, at least for the generation and transmission cost components. Under such an arrangement, peak generation capacity costs could be based on the collective coincident demand of all of EVgo's DCFC on a utility's system during peak hours.

There are other ways that EVgo could potentially reduce its costs, using technology solutions like on-site solar or electricity storage systems that could be called upon to deliver power when grid power costs are high, or when the charger is at risk of triggering demand charges. However, our analysis was restricted to tariff-based solutions.

SUGGESTIONS FOR FURTHER STUDY

Although the current usage patterns of charging infrastructure suggest that it is easier for Level 2 chargers than it is for DCFC to shift their loads in response to TOU tariffs and provide grid benefits (such as demand response and ancillary services), more sophisticated and detailed modeling of DCFC's demand flexibility may offer some useful insights, particularly if DCFC are paired with on-site solar systems, an Option R tariff and/or on-site supplementary battery storage systems that can be deployed to shave demand peaks.

That kind of modeling work does not appear to have been done to a deep level as yet; most of the existing work has looked at the potential value streams of EVs as grid assets from the perspective of the bulk power system or in terms of the total societal impact, rather than at a granular level where effects on the distribution system over time could be assessed. It may very well be, for example, that the cost of a PV canopy and a redundant battery storage array located with a DCFC looks prohibitive at first blush, but a detailed modeling of the revenue potential in such a configuration would show that it would not only substantially reduce the direct costs of the DCFC by shaving or avoiding peak pricing and demand charges, but earn significant revenue for selling grid services to utilities, and enabling the uptake of renewable power on the grid to a degree that public utility commissioners see the value in developing performance-based incentives around it.

ENDNOTES

[1] United States GDP Growth Rate, Trading Economics. http://www.tradingeconomics.com/united-states/gdp-growth

[2] RMI, Peak Car Ownership. 2016. https://rmi.org/Content/Files/CWRRMI_POVdefection_FullReport_L12.pdf

[3] Data on the number of gasoline filling stations in California is hard to find, but this source suggests 13,500, which seems in the right ballpark. If we assume 6 pumps per station, then there would be 81,000 pumps in California, compared to the 63,500 DCFC in California in 2027 under Scenario 4. http://www.answers.com/Q/How_many_gas_stations_in_California?#slide=2

[4] Documents pertaining to CPUC proceeding R.13-11-007 may be found here: https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO

[5] San Diego Gas & Electric, "Application of San Diego Gas & Electric Company (U 902-E) for Authority to Implement Priority Review and Standard Review Proposals to Accelerate Widespread Transportation Electrification," January 20, 2017. https://www.sdge.com/regulatory-filing/20491/application-sdge-authority-implement-priority-review-and-standard-review

[6] "Prepared Direct Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

[7] "Prepared Testimony of Randy Schimka on Behalf of San Diego Gas & Electric Company, Chapter 3," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%203%20-%20Priority%20Review%20Projects.pdf

[8] Ibid.

[9]

> A CPP [Critical Peak Pricing] rate is a commodity rate structure that includes a higher energy price ($/kWh) applied to peak periods on critical system event days that are called on a day-ahead basis. The CPP rate is designed to recover the costs of system capacity during event days, up to 18 days per year with an assumed nine days per year, called on a day-ahead basis rate rather than through a peak demand charge every month of the year in order to solicit demand response....Customers will be notified on a day-ahead basis when forecasted load exceeds an established threshold with the threshold

calculated based on the top 150 system hours from the previous year, which represents approximately 1.71% of annual hours. By moving from a ToU rate structure to an hourly dynamic rate structure, the proposed TE commodity rate allows SDG&E to focus on a small number of truly high cost hours, the 150 system peak hours, while still reflecting the cost basis of commodity services.

"Prepared Direct Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

[10] Historic circuit load will be used to determine the threshold amount for forecasting the top 200 circuit peak hours. When the forecast identifies an hour exceeding the prior year's top 200-hour threshold, a D-CPP Hourly Adder will be applied and presented to the customer on a day-ahead basis. Year-to-year differences in load can result in actual circuit peak hours that differ from the forecasted top 200 hours.

Ibid.

[11] Ibid.

[12] "Prepared Direct Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

[13] Assuming a 32 mpg Nissan Sentra ICE vehicle, $3/gallon of gasoline (based on CA price in Q4 2016) 0.32 kWh/mile typical EV performance, and $12/MWh CAISO day-ahead pricing in central San Diego (as of February 14, 2017). http://gasprices.aaa.com/?state=CA; https://www.fueleconomy.gov/feg/bymodel/2015_Nissan_Sentra.shtml;

http://www.afdc.energy.gov/vehicles/electric_emissions_sources.html.

[14] Southern California Edison, "Testimony of Southern California Edison Company in Support of its Application of Southern California Edison Company (U 338-E) For Approval of its 2017 Transportation Electrification Proposals," January 20, 2017. http://on.sce.com/2kXeu1X

[15] Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future*. Montpelier, VT: Regulatory Assistance Project. http://www.raponline.org/document/download/id/7680

[16] "While the costs of utility services are incurred in the same manner for all customer classes, there is little consistency in how costs are recovered from each customer class, with the rate structure for some customer classes recovering costs in a manner that does not reflect cost causation." "Prepared Direct Testimony of

Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017.
https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

[17] CPUC Decision 14-12-080, "Decision on a Rate Design Proposal to Adopt an Option R Tariff for Pacific Gas and Electric Company," December 18, 2014.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K631/143631744.PDF

[18] Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future*. Montpelier, VT: Regulatory Assistance Project.
http://www.raponline.org/document/download/id/7680

[19] Chris Nelder, James Newcomb, and Garrett Fitzgerald, Electric Vehicles as Distributed Energy Resources (Rocky Mountain Institute, 2016),
http://www.rmi.org/pdf_evs_as_DERs

[20] SDG&E Time of Use Plus (Critical Peak Pricing- CPP-D) option.
http://www.sdge.com/business/demand-response/cpp

ROCKY MOUNTAIN INSTITUTE

1820 Folsom Street
Boulder, CO 80302 USA
http://www.rmi.org

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	)
Application of Duke Energy Progress,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Service	)
in North Carolina	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-7

AN ALLETE COMPANY

Jenna Warmuth
Senior Public Policy Advisor
218-355-3448
jwarmuth@mnpower.com

May 16, 2019

VIA ELECTRONIC FILING
Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of Minnesota Power's Docket No. Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot Docket No. E015/M-19-___

Dear Mr. Wolf:

Minnesota Power herby submits this Petition to the Minnesota Public Utilities Commission ("Commission") in accordance with Commission Order in Docket No. E999/CI-17-879 and pursuant to Minnesota Rules 7829.00, subp. 1, and 7826.1300. Minnesota Power is proposing a three year Electric Vehicle Commercial Charging Rate Pilot for Commercial and Industrial Customers (the "Pilot Program"). The Pilot proposal consists of on-and-off peak periods as well as a 30 percent cap on demand charges and is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications.

This Pilot is an important first step in incentivizing EV adoption and meeting the needs of early adopting customers. Minnesota Power is submitting this Pilot Program proposal to the Commission in order to take advantage of current and upcoming EV opportunities within its service territory while meeting customer expectations.

<u>Objectives for the Pilot:</u>
Ease of Use: The Company designed the Pilot so that it is easy for customers to implement and utilize.

Education and Learning: The Pilot should allow customers to get comfortable with the EV charging technology and provide information to Minnesota Power about the costs to serve these customers. Many of these customers have never worked with EV charging infrastructure and will require time to adapt and experiment for optimal usage.

The Company appreciates the Commission's attention to this matter and is available to answer any questions related to the proposed Pilot Program.

Please contact me at the number above with any questions related to this matter.

Respectfully,

Jenna Warmuth

STATE OF MINNESOTA

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot	Docket No. E015/M-19-___ **PETITION**

Summary of Filing

Minnesota Power (or "the Company") submits this Petition to the Minnesota Public Utilities Commission ("Commission") in accordance with Commission Order in Docket No. E999/CI-17-879 and pursuant to Minnesota Rules 7829.00, subp. 1, and 7826.1300. Minnesota Power respectfully requests that the Commission approve its Electric Vehicle Commercial Charging Rate Pilot as proposed.

Table of Contents

Table of Figures

Table of Tables

Attachments:

STATE OF MINNESOTA

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot	Docket No. E015/M-19-___ **PETITION**

I. INTRODUCTION

In its February 1, 2019 Order Making Findings and Requiring Filings, the Minnesota Public Utilities Commission established general findings, specific findings, and outlined directives for Minnesota's utilities related to the advancement and adoption of electric vehicle ("EV") integration.

General Findings:

- ❖ Electrification is in the public interest
- ❖ Barriers to increased EV adoption in Minnesota include but are not limited to: (a) inadequate supply of and access to charging infrastructure, and (b) lack of consumer awareness of EV benefits and charging options.
- ❖ How EVs are integrated with the electric system will be critical to ensuring that transportation electrification advances the public interest.
- ❖ Minnesota's electric utilities have an important role in facilitating the electrification of Minnesota's transportation sector and optimizing the cost-effective integration of EVs.

Specific Findings:

- ❖ Minnesota's investor owned utilities should take steps to encourage the cost-effective adoption and integration of EVs
- ❖ The following should be included at a minimum in any EV-related utility proposals:
    - o Any EV-related proposals that involve significant investments for which the utility is seeking or will seek cost recovery should include a cost-benefit analysis that shows the expected costs along with the expected ratepayer, system and societal benefits associated with the proposal
    - o In the case of a proposed pilot, the utility filing should include specific evaluation metrics for the pilot and identify what the utility expects to learn from the pilot.
- ❖ Utilities should use the Commission's current environmental externality values for carbon and criteria pollutants in analyzing the societal costs and benefits associated with EV-related proposals. Cost-benefit analyses should consider potential long-term ratepayer and societal benefits, including better grid management, public health, and other social

benefits. These analyses should also consider potential long-term costs, including the risk of stranded investment.

- ❖ The Office of the Attorney General ("OAG") suggested three-step process for evaluating utility investments in public charging infrastructure is reasonable.
- ❖ Utility investments and arrangements related to charging infrastructure should be designed to ensure interoperability, using standard such as Open Charge Point Protocol and Open Automated Demand Response.
- ❖ No single method of cost recovery should be generally precluded at this time for any EV-related investments.
- ❖ Minn. Stat. § 216B.1614, subd. 2(c)(2), allows utilities the opportunity to recover costs related to educating customers on the benefits of EVs beyond those costs related specifically to the utility's EV tariffs.

Actions:

Table 1: Commission Action - Electric Vehicles

Filing	Due Date
Report of planned 2019 EV proposals	March 31, 2019
Annual EV Reports required under Minn. Stat. § 216B.1614, subd. 3, including promotional cost recovery mechanisms	June 1, 2019
Transportation Electrification Plan	June 30, 2019
Proposals for infrastructure, education, managed charging, etc.	No later than October 31, 2019

- ❖ In any future pilot proposal, utilities should include a discussion of the following topics to the extent relevant:
  - o Environmental justice, with a focus on communities disproportionately disadvantaged by traditional fossil fuel use;
  - o Low-income access and equitable access to vehicles and charging infrastructure, which can include all-electric public transit and EV ride-sharing options;
  - o Environmental benefits, including but not limited to carbon and other emission reductions;
  - o Potential economic development and employment benefits in Minnesota;
  - o Interoperability and open charging standards;
  - o Load management capabilities, including the use of demand response in charging equipment or vehicles;
  - o Energy and capacity requirements;
  - o Pilot expansion and/or transition to permanent status at a greater scale;

- Education and outreach;
- Market competitiveness/ownership structures;
- Distribution system impacts;
- Cost and benefits of the proposal;
- Customer data privacy and security; and
- Evaluation metrics and reporting schedule.

Minnesota Power submits this Petition in accordance with the above referenced Commission findings and actions.

SUMMARY OF PILOT PROPOSAL:

Minnesota Power is proposing a three year Electric Vehicle Commercial Charging Rate Pilot for Commercial and Industrial Customers (the "Pilot Program"). The Pilot proposal consists of on-and-off peak periods as well as a 30 percent cap on demand charges and is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications, as depicted in Table 2. This Pilot proposal is an initial step towards incentivizing EV charging and will need to be refined as current barriers, as outlined in Section II, are overcome and knowledge is gained. Full details of the Pilot proposal rate structure can be found in Section III of this Petition.

Table 2: Tariff Design

	CURRENT GENERAL SERVICE DEMAND TARIFF	PROPOSED PILOT PROGRAM TARIFF
ON-PEAK DEMAND CHARGE[1]	$6.50	$6.50
OFF-PEAK DEMAND CHARGE	$6.50	$0.00
ENERGY CHARGE	$0.07619	$0.07619
OTHER		30% DEMAND CAP

PURPOSE AND OBJECTIVES OF THE PILOT PROPOSAL:

Minnesota Power is submitting this Pilot proposal to the Commission in order to take advantage of current and upcoming EV opportunities within its service territory while meeting customer

[1] Minnesota Power's standard General Service rate does not include on-and-off-peak periods.

expectations. The Company is placing an emphasis on encouraging a growing market by reducing costs to public and fleet EV charging customers.

Objectives for the Pilot:

Ease of Use: The Company designed the Pilot so that it is easy for customers to implement and utilize.

Education and Learning: The Pilot should allow customers to get comfortable with the EV charging technology and provide information to Minnesota Power about the costs to serve these customers. Many of these customers have never worked with EV charging infrastructure and will require time to adapt and experiment for optimal usage.

Minnesota Power respectfully requests that the Commission approve its Electric Vehicle Commercial Charging Rate Pilot as proposed.

II. PROCEDURAL MATTERS

In accordance with Minn. Rule Minn. Stat. § 216B.1614, as well as the administrative rules governing this request, Minn. R. 7829.1300, Minnesota Power submits its Electric Vehicle Commercial Charging Tariff Pilot proposal.

Minnesota Power submits the following information:

A. Name, Address, and Telephone Number of Utility
(Minn. Rules 7825.3500 (A) and 7829, subp. 3 (A))
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722-2641

B. Name, Address, and Telephone Number of Utility Attorney
(Minn. Rules 7825.3500 (A) & 7829, subp. 3 (B))
David R. Moeller, Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 723-3963
dmoeller@allete.com (e-mail)

C. Date of Filing and Date Proposed Rates Take Effect
This petition is being filed on May 15, 2019. The proposed rate will take effect upon Commission approval.

D. Statute Controlling Schedule for Processing the Petition
This petition is made in accordance with Commission Order in Docket No. E999/CI-17-879 and pursuant to Minnesota Rules 7829.00, subp. 1, and 7826.1300.

Minnesota Power's request for its Electric Vehicle Commercial Charging Tariff Pilot, falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11 and 7829.1400, subp. 1 and 4 permitting comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed no later than 10 days thereafter.

E. Utility Employee Responsible for Filing
Jenna Warmuth
Senior Public Policy Advisor
30 West Superior Street Duluth, MN 55802
(218) 355-3448
jwarmuth@mnpower.com (e-mail)

F. Official Service List

Pursuant to Minn. Rule 7829.0700, Minnesota Power respectfully requests the following persons to be included on the Commission's official service list for this proceeding:

David R. Moeller	Jenna Warmuth
Senior Attorney	Senior Public Policy Advisor
Minnesota Power	Minnesota Power
30 West Superior	30 West Superior Street
Duluth, MN 55802	Duluth, MN 55802
(218) 723-3963	(218) 355-3448
dmoeller@allete.com	jwarmuth@mnpower.com

G. Service on Other Parties

Minnesota Power is eFiling this report and notifying all persons on Minnesota Power's General Service List, Service Lists for Docket Nos E999/CI-17-879 and E015/M-15-120 that this report has been filed through eDockets. A copy of the service list is included with the filing along with a certificate of service.

H. Filing Summary

As required by Minn. Rule 7829.1300, subp. 1, Minnesota Power is including a summary of this filing on a separate page.

SUMMARY OF FILING REQUESTS

Based on information provided throughout this filing, Minnesota Power requests the following:

From the MPUC:

❖ Acceptance of its proposed Electric Vehicle Commercial Charging Tariff Pilot.

III. BACKGROUND

In its June 1, 2018 annual compliance filing in Docket No. E015/M-15-120, Minnesota Power communicated its intent to submit a commercial EV tariff designed to address high demand charges typically associated with commercial EV charging and shift EV charging to off-peak time periods. As described in the June 1, 2018 filing, one driver for the focus on commercial EV charging rates is the Duluth Transit Authority's ("DTA") procurement of seven fully electric Proterra[2] transit buses in the third quarter of 2018. The Company has worked with the DTA to understand the customer experience and challenges of operating electric buses in a northern climate. In addition to the DTA, Minnesota Power has engaged in conversations with customers interested in converting their fleets to electric vehicles, potential site hosts for public charging stations, and public charging companies that have deployed (or plan to deploy) EV charging within Minnesota Power's service territory to better understand their challenges as they relate to Minnesota Power rates. The insights gained from these conversations and interactions were used in the development of this Pilot.

In its February 1, 2019 Order Making Findings and Requiring Filings in Docket No. E015/M-17-879, the Commission directed the investor-owned utilities in Minnesota to file proposals, which can be pilots, to enhance the availability of or access to charging infrastructure, increase consumer awareness of EV benefits, and/or facilitate managed charging or other mechanisms that optimize the incorporation of EVs into the electric system. Minnesota Power recognizes that EV-enabling rates are a critical component of advancing the electric vehicle market in Minnesota. This Pilot proposal is intended to provide a short-term solution to barriers commonly experienced in commercial charging applications while also recognizing that more information is needed before Minnesota Power can formulate a permanent rate for these applications.

Utilities around the country are working to understand how to best serve this emerging class of customers through rates, infrastructure, programs and more. A report released in January 2019 by The Brattle Group describes the options for increasing adoption of direct current fast charging stations ("DCFC") through rates.[3] According to the report, "designing the "perfect" DCFC rate may not need to be the top priority initially. Experimentation and learning what works to facilitate DCFC adoption in an equitable and efficient manner may be more appropriate near-term objectives." Placing limits on demand-related charges, as this Pilot proposes to do, is one option described in the report as a means to facilitate DCFC deployment.

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[2] See https://www.proterra.com/ for more information.
[3] See http://files.brattle.com/files/15077_increasing_ev_fast_charging_deployment_-_final.pdf

STAKEHOLDER OUTREACH

Minnesota Power intentionally engaged multiple stakeholders in the development of this Pilot. These stakeholder included the Duluth Transit Authority, Fresh Energy, Office of the Attorney General, Department of Commerce, ChargePoint, Citizens Utility Board, Greenlots, Tesla and ZEF Energy. While not all of the stakeholder's concerns or needs could be addressed in this initial Pilot design, the discussions have proven valuable and the Company is better prepared to address each stakeholder's concerns. The Pilot analysis will also be designed in a way that will provide insight into these areas of concern and interest.

Consultation with customers and the above-mentioned stakeholders informed the development of this Pilot proposal which is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications. Utilities around the country are working to better understand the characteristics of EV charging customers in an attempt to develop best practices to encourage optimized charging. The enclosed Pilot proposal was designed as a short-term solution to meet the immediate needs of commercial customers who have installed, or are considering installing, EV charging infrastructure for public and fleet applications. A bridging solution is needed to remove barriers to entry into the market while the Company continues to gather and analyze data needed to design a rate that provides more accurate price signals for optimized charging. This Pilot is an educational tool for customers to begin experimenting with load shifting. It is meant to encourage thoughtful and beneficial charging that will not only reduce costs for EV customers, but also support enhanced grid management.

TECHNOLOGY AND METERING CONSIDERATIONS

Currently, over 50 percent of Minnesota Power's meters in the field are advanced metering infrastructure ("AMI"). Minnesota Power is actively deploying AMI throughout its service territory, largely through meter attrition, at a rate of approximately 6-8 percent (roughly 10,000 meters) annually, continuing over the next several years. Minnesota Power estimates full deployment of all AMI meters by the end of 2025. Along with the AMI meter deployment, Minnesota Power completed implementation of its Radio Frequency AMI network communications infrastructure in 2018.

Upon implementation of its new Meter Data Management ("MDM") system, the Company will have the capability to bill customers utilizing hourly data received from the meters. Usage bucketing will be handled by the MDM, thereby removing the need for manual custom programming of meters for more complex time-varying rates. Consequently, scalability and speed to enroll customers in an innovative or time-varying rate will increase significantly and the associated cost will decrease significantly. With a MDM in place, it is easier for the meters to communicate usage rather than the current practice of getting them to recognize and accept a command. This will result in fewer billing issues and far less manual billing interventions. In the current context, the meters bucket all usage and communicate a large daily file back to the Company's Customer Information System ("CIS"). With a full AMI/MDM established, the data will be transmitted several times a day, which typically equals greater success. A MDM will also allow for flexibility to efficiently change the time periods for rates.

The Company completed a request for proposal ("RFP") process and MDM selection in late 2018. As a result of its robust RFP process, the Company selected the Oracle Customer to Meter Solution ("Oracle C2M") in November of 2018. The next step in the MDM implementation process is to select a System Integrator ("SI") to assist with the design, build, testing, and implementation of the Oracle C2M solution. The Company currently has an RFP process underway and anticipates SI selection in 3rd quarter of 2019. The presence of a MDM will create a more user-friendly experience for customers and also has the potential to drastically reduce manual billing and programming issues currently experienced with customized rates and programs.

With the complete deployment of AMI and the implementation of the MDM Minnesota Power will have the capability to efficiently revise peak time periods as well as gain enhanced insight into customer usage patterns. In all practicality, an MDM solution needs to be in place systemically prior to system-wide rollout of several time varying rate programs. The Company is currently awaiting Commission direction on its February 20, 2019 filing in Docket No. E015/M-12-233 which outlines how a system-wide Time-of-Day rate could be implemented in Minnesota Power's service territory. The outcome of this docket will likely inform many program offerings, including this Pilot proposal.

IV. TARIFF DESIGN

TARIFF DESIGN OVERVIEW:

Minnesota Power is proposing an Electric Vehicle Commercial Charging Rate Pilot for Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through a separate meter. The Pilot proposal will have a limited three-year term. Service will be limited to customers with total power requirements greater than 10 kW but less than 10,000 kW and will be subject to Company's Electric Service Regulations and any applicable Riders. With the continued expansion of transportation electrification, the Company is interested in gathering data on how best to serve these customers and the costs to serve this customer class, while at the same time providing incentives to efficiently and cost-effectively utilize grid resources.

The Company examined the usage patterns of six commercial customers who currently have electric vehicle charging infrastructure in use. All of these customers are currently billed under the General Service Demand ("GSD") rate. As shown in Table 3 the current demand charge total represents more than 50 percent of these customers' bills, and in some cases more than 80 percent. Dividing an average GSD customer's total bill by their monthly usage results in a cost of roughly $0.08 per kWh, whereas these commercial EV charging customers are typically paying more than four times that amount.

The Company compared these six customers to all GSD customers and found that they are in the upper 90th percentile when customer bills are expressed as a dollars per kWh metric ("$/kWh"). This is directly related to these customers having relatively low load factors, which ranged from approximately 1% – 8%. Knowing that customers with low load factors also tend to have low coincidence factors, it stands to reason that these type of customers are less likely to experience peak demands coincident with the Company's system peak. To address the fact that these customers are paying significantly more per kWh than nearly all other GSD customers, the Company is proposing to implement a cap on demand charges. The proposed demand charge for this pilot will not make up more than 30 percent of a customer's monthly bill, and in addition, demand charges during off-peak time periods will be eliminated altogether to promote customer charging at times that are more advantageous to the distribution grid.

The purpose of the proposed 30 percent demand cap is to bring these customers more in-line with other GSD customers on a $/kWh basis. As shown in Table 4 doing so moves these customers closer to the average $/kWh percentile rank with an average total rate of roughly $0.12 per kWh.

Table 3: Current Demand Charge Impact

Customer	Demand Charge as % of Bill	Bill/kWh	Percentile Rank (Bill/Kwh) among GSD
1	56%	$ 0.19	94.8%
2	75%	$ 0.34	98.8%
3	73%	$ 0.31	98.7%
4	78%	$ 0.38	99.1%
5	78%	$ 0.39	99.1%
6	88%	$ 0.78	99.7%

Table 4: Demand Charge Impact of Pilot Tariff

Customer	Demand Charge as % of Bill	Bill/kWh	Percentile Rank (Bill/Kwh) among GSD
1	30%	$ 0.12	65.5%
2	30%	$ 0.12	67.0%
3	30%	$ 0.12	67.7%
4	30%	$ 0.12	69.7%
5	30%	$ 0.12	69.8%
6	30%	$ 0.14	82.7%

Demand charges serve a specific purpose for incentivizing flattening of individual customer peak loads. However, as outlined in the Regulatory Assistance Project's ("RAP") June 2018 "Ensuring Electrification in the Public Interest" report, "*the intent of beneficial electrification should be to provide incentives for customers to adjust their usage in a way that is helpful for managing system peaks.*"[4] The report goes on to state, "*more effective rate structure[s] would encourage these customers to move their charging to off-peak times for the grid as a whole, when it is less stressed*

[4] Farnsworth, Shipley, Lazar, Seidman "Ensuring Electrification in the Public Interest" https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/

and less expensive to serve (Farnsworth, et al. 43)." The peak periods also proposed through this Pilot are an appropriate and advantageous starting point to meet these beneficial electrification objectives. By reducing the impact of demand charges for these customers, it provides flexibility for them to charge at times that are more advantageous to the distribution grid.

Demand Charge for On-Peak

For the purposes of this Pilot proposal the Billing Demand is defined as the kW measured during the 15-minute period of the customer's greatest use during the specified On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods are defined as 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. Holidays are those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. All other hours are considered to be Off-Peak periods and there is no demand charge applied during these times. Minnesota Power recognizes that targeted On-Peak time periods would be ideal for this rate and for these customers. However, there are currently limitations to the AMI and MDM data/billing process as discussed earlier in this filing, as well as limited information on the usage patterns for these customers. Attempting to create a more targeted peak period for these commercial load customers is unadvisable without first providing an opportunity for both customer and utility education and analysis.

While the current/proposed On-Peak period covers a broad portion of the day, it does generally align with the Company's system load profile as depicted in Figure 1. Minnesota Power has a high load factor due to the predominance of large industrial customers in its customer mix. This translates to a unique load profile when compared to other utilities across the United States. Minnesota Power's system is winter-peaking, with highest demand typically occurring on a winter evening, either in December or in January. It is also notable that the summer system peak typically occurs earlier in the day, in the afternoon, compared to the evening winter peak. The proposed On-Peak period for the Pilot follows these high demand time periods and will not only aid the Company in more effectively managing its grid resources, but will also take advantage of periods of high renewable penetration, mainly wind, during the overnight hours.

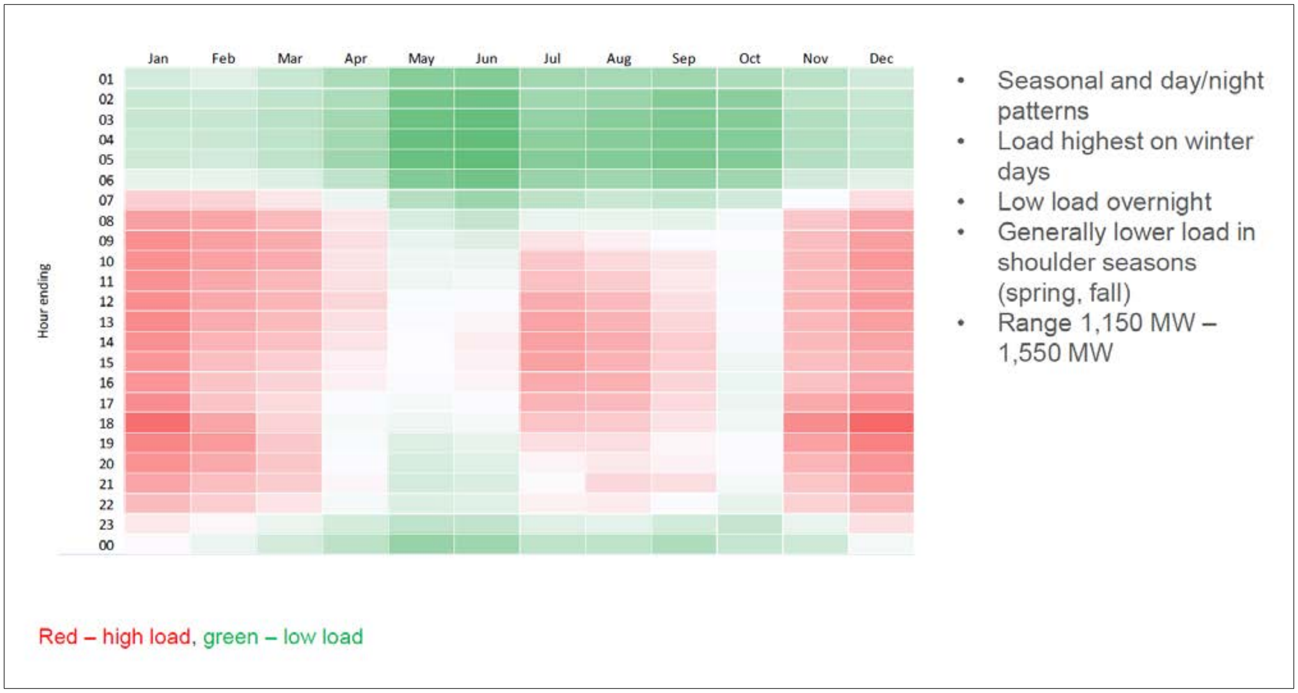

Figure 1: Gross Load Heat Map

Energy Charge for all kWh

The energy charge for the Pilot proposal will be set equal to the standard GSD rate energy charge. At this time Minnesota Power's GSD energy charge is equal to 7.619¢. This rate will be multiplied by all kWh used during the billing period.

Barriers Addressed through Tariff Design

At a high-level the Company is attempting to address the most prominent barriers to fleet and public EV charging applications with this Pilot. The Company realizes this is not a definitive solution and is excited to partner with customers that are going through early iterations of business model and technology pilots in the electrification of transportation movement. For fleet, the long-term strategy will be to send price signals that incentivize customers to charge when it's most beneficial for the grid– times of high overall available capacity. At face-value it may seem that fleet owners will be able to be precise and intentional with their charging patterns, but as medium and heavy duty fleet technology is still in the very early stages (especially within Northern Minnesota and cold climates) there needs to be room for flexibility. Transit, short-haul delivery, and school buses may not be able to limit their charging to the off-peak hours and still meet the current needs of business-as-usual, i.e. no impacts to their current routes.

As mentioned, the Company has engaged the DTA in ongoing discussions to support its innovative program. Minnesota Power is interested in providing alternative rate design options for low-load-factor customers similar to the DTA and public charging that wish to deploy DCFC. Load factor characteristics often associated with facilities deploying DCFC stations can lead to high demand charges for charging stations relative to their low utilization of energy, thereby reducing the cost effectiveness of electric transit options. Recognizing the significantly different load profile of DCFC facilities as compared to average commercial customers, the Company developed its Pilot proposal to mitigate these high demand charges. This program will also educate customers on the benefits of off-peak charging and provide incentives to shift demand to off-peak times.

For both fleet and public vehicle charging, demand charges are a barrier, but most significantly to a public charging station, which typically has a low load-factor. By capping demand rate billings, the Company is minimizing the economic risks to these public charging station owners, which are so critical to the advancement of electric transportation adoption. The 30 percent cap was determined to be a balanced approach that recognizes most public charging takes place during the On-Peak period, but lowers the impact that demand would have to a level that doesn’t discourage progress. All while the industry transitions to rates that support beneficial electrification and grid modernization.

V. COMPLIANCE

Low-income access and equitable access to vehicles and charging infrastructure, which can include all-electric public transit and EV ride-sharing options;

"*According to a 2017 report from the Center for Climate and Energy Solutions[5], emissions-related health issues like higher risk of cancer, asthma, emphysema, heart disease and inhibited child development disproportionately impact lower income communities. … EVs can combat these issues, according to the report, benefiting these communities three-fold through improved air quality, reduced greenhouse gas emissions and savings in terms of operating costs like fuel and maintenance expenses.[6]"* As outlined in the Center for Climate and Energy Solutions report, the expansion of any fleet, transit, or public charging expansion will positively affect low income customers because EVs produce no tailpipe emissions. The Company recognizes the need for tailored low income EV programming and plans to examine possible program structures for future development.

The intent of this Pilot proposal is to encourage deployment of commercial EV charging applications including work place, public and fleet such as electric buses. While this Pilot is not specifically designed to increase low income or equitable access to EV charging, increasing the amount of EV chargers available for public use will benefit all Minnesota Power customers.

Environmental benefits, including but not limited to carbon and other emission reductions;

In 2017, transportation was the leading sector for GHG emissions in United States[7]. As the electricity sector continues to reduce emissions this will only improve the environmental benefits of electrifying the transportation sector.

Electric Vehicles eliminate (Battery Electric Vehicles (BEV)) or dramatically reduce (Plug-in Hybrid Electric Vehicles) tailpipe emissions (nitrogen oxides (NOx), and fine particles ($PM_{2.5}$)) from individual vehicles, as well as reduce the overall "well-to-wheel" greenhouse gas emissions (GHG) associated with electrifying the transportation sector[8]. A BEV charged from Minnesota's grid vs. a gasoline vehicle already emits less overall carbon dioxide equivalent (CO_2e), NO_x, and $PM_{2.5}$ according to the Minnesota Pollution Control Agency, as shown below. Electricity is continually sourced from cleaner and more renewable sources, only improving the projections of environmental benefits

[5] https://www.c2es.org/site/assets/uploads/2017/11/electrified-transportation-for-all-11-17-1.pdf

[6] https://sustainableamerica.org/blog/making-evs-possible-for-low-income-drivers/

[7] https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

[8] https://www.pca.state.mn.us/air/electric-vehicles

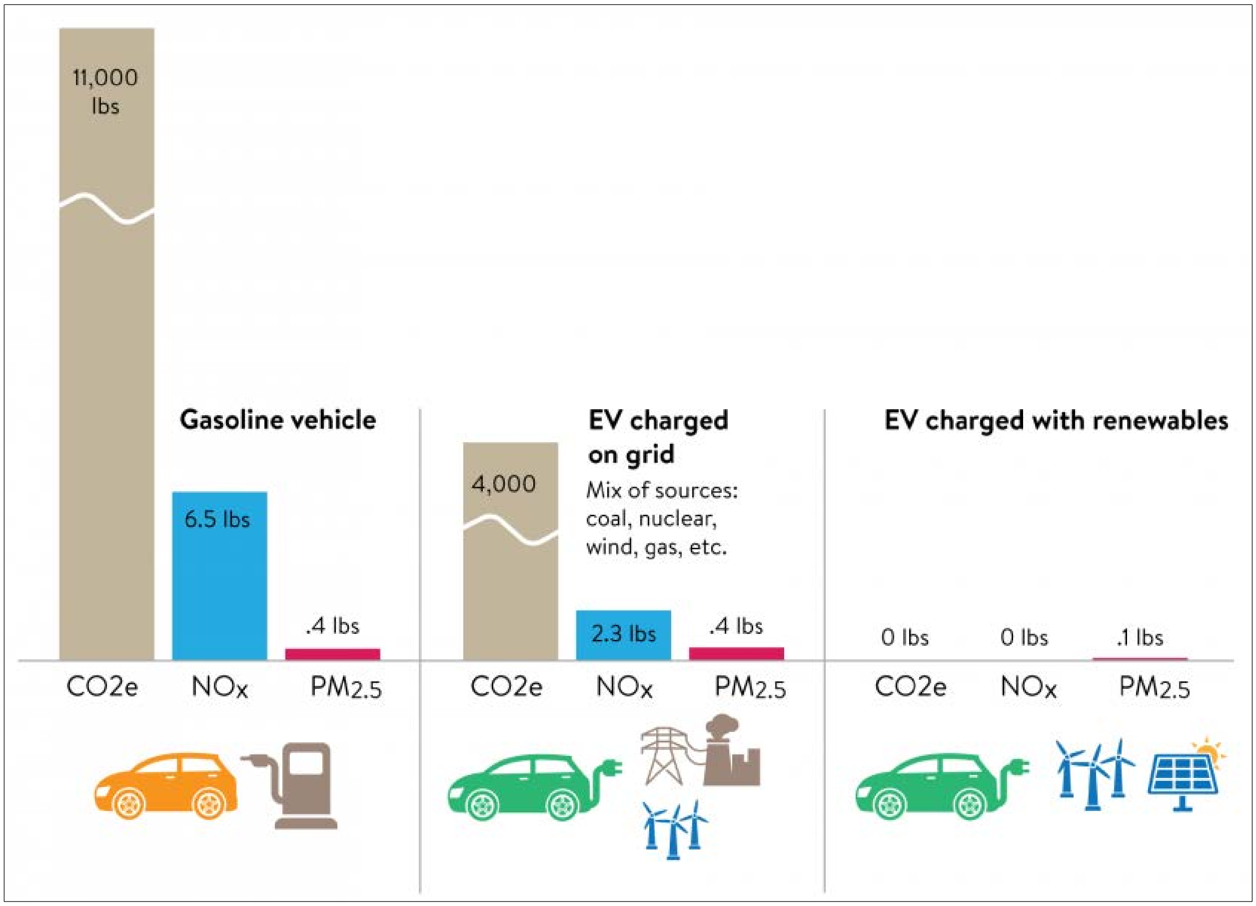

Figure 2: Annual emissions from electric vehicles and gasoline vehicles in Minnesota (12,000 miles)

Furthermore, optimizing when these vehicles charge through price signals to the customer, or future technology-based smart charging could aid in minimizing the impacts of adding to system peaks or need for additional capacity. Electric vehicles are more energy efficient and at the center of the beneficial electrification movement. According to the U.S. Department of Energy, EVs convert about 59 to 62 percent of the electrical energy from the grid to power at the wheels. Their internal combustion engine counterparts only convert 17 to 21 percent of the energy stored in gasoline to power at the wheels[9]. These efficiency numbers do not include energy used in the production of the electricity or gasoline.

In addition to Light Duty Vehicles, Minnesota Power considers public transit greatly important when prioritizing initiatives to support the growth of various applications of electric transportation. "By moving more people with fewer vehicles, public transportation can reduce greenhouse gas emissions. National averages demonstrate that public transportation produces significantly lower

[9] https://www.fueleconomy.gov/feg/evtech.shtml

greenhouse gas emissions per passenger mile than private vehicles[10]". Electrifying public transit, which is already more efficient in principle than light-duty vehicles, will only improve the reductions in GHG and optimization of the grid. A Battery Electric Bus ("BEB") represents a significantly higher amount of demand and energy usage.

According to a 2018 study conducted by the National Renewable Energy Laboratory ("NREL") in California, BEBs demonstrated more than twice the efficiency on a miles per gallon equivalent, compared to a diesel bus.[11] The Duluth Transit Authority is currently participating in a similar pilot. While these results are promising, Minnesota Power and the DTA have been in communications about the various other benefits and drawbacks unique to our region and climate.

Energy and capacity requirements;

The Company expects minimal short-term change in energy and capacity requirements due to the initiation of this Pilot. However, the longer-term impacts of this Pilot or any subsequent Commercial EV rate could be substantive.

Energy and capacity requirements will grow with EV adoption. The proposed Pilot is not intended to reduce energy use, only to shift that energy use to off-peak periods. Overall energy requirements are unlikely to be affected by this Pilot in the short-term. However, in the long-term, it's likely that the incentive offered in this Pilot will accelerate adoption of EV's and increase overall energy requirements on the system. Any on-peak to off-peak load shifting will reduce the Company's system demand relative to a "no load-shifting" scenario.

Education and outreach;

Minnesota Power has continually engaged current and potential EV owning commercial customers as outlined through this Petition. The Company will continue to reach out to known EV owning commercial customers as well as make efforts to perform outreach to other potential qualified commercial customers.

The Company will advertise the Pilot program to potential qualified customers through its website, promotional materials and one-to-one contacts. The Company works closely with its commercial customers and plans to highlight the benefits of EV ownership as well as the optionality the Pilot proposal can provide their business and customers.

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[10]https://www.transit.dot.gov/regulations-and-guidance/environmental-programs/transit-environmental-sustainability/transit-role

[11] https://afdc.energy.gov/files/u/publication/zero-emission_evaluation_county_connection_bec.pdf

Distribution system impacts;

The Company expects the Pilot program to have minimal impact on the distribution system in the short-term. Existing and future commercial EV customers are currently required to pay for installation of any distribution equipment upgrades necessary to serve new EV load. As such, these customers' EV loads do not currently present a burden for the distribution system. However, as EV charging becomes more prominent and demands on the distribution system increase, it will be beneficial to limit on-peak charging, particularly in fleet applications.

Cost and benefits of the proposal;

The cost of the Pilot proposal will relate to the addition of the installation of the required service, and can vary significantly based on customer location and energy use characteristics. All customers participating in the Pilot will require some additional meter programming to facilitate a difference in on/off-peak demand charges. This programming has a small incremental cost relative to a standard GSD meter, but these costs are not substantial enough at this time to justify additional monthly service charges.

The overall benefits of the proposal to Minnesota Power and customers will depend on how much energy use is shifted to off-peak time periods. Minnesota Power will quantify and analyze the costs and benefits of the Pilot through the various performance metrics outlined in this Petition.

Customer data privacy and security;

Minnesota Power will clarify in each participating customer's service agreement the data to be assigned trade secret and public designation. In keeping with Commission Order[12], the Company will only share a customer's data for a purpose other than related to regulated utility service after the utility obtains consent from the customer that includes a clear statement of the information to be shared and with whom it will be shared.

Evaluation metrics and reporting schedule;

Minnesota Power will track several metrics to assess the success of its proposed Commercial EV charging pilot. Several of these metrics are comparable to cost allocation factors used in Customer Cost of Service Studies and may indicate whether or not the Company was successful in reducing service costs. Other metrics focus on the customer's savings under this EV rate.

1. Daily/monthly coincidence factors - with Minnesota Power system peak and MISO system peak,
2. Daily/monthly on/off-peak and overall load factor
3. Average $/kWh and respective percentile rank within GS Demand
4. Comparison of final bills under different rate structures
5. Daily/monthly kW demand on and off- peak

[12] June 24, 2014 Order in Docket No. E,G-999-CI-12-1344

6. Pre-pilot usage for comparison.
7. Growth in the number of fleet EV or public charging stations.

Minnesota Power will leverage these metrics and stakeholder feedback to inform future rate and program development.

Pilot expansion and/or transition to permanent status at a greater scale;

Minnesota Power will offer the Pilot rate for a three-year period, thereby allowing the Company to:

- gather the information needed to design a rate that sends more accurate price signals and is based on the costs to serve EV charging customers,
- coordinate with the Company's other efforts including the MDM implementation, AMI deployment and time-of-day rate proceeding,
- encourage increased adoption of electric vehicles in northern Minnesota by decreasing the costs associated with public and fleet charging and allowing customers time to experiment with charging patterns and capabilities;
- and provide benefits to all Minnesota Power customers by encouraging charging in the off-peak where possible and increasing load, spreading system costs across a larger customer base.

The Company intends to evaluate the rate during the three-year pilot period based on the criteria listed in this petition and determine whether a commercial EV charging rate is needed going forward and if so, what changes are needed to better optimize EV charging in the future and as adoption increases.

VI. CONCLUSION

Minnesota Power submits this Petition in accordance with Commission findings and actions in Docket No. E999/CI-17-879. The Company appreciates the Commission's attention to this Pilot proposal. This Pilot is an important first step in incentivizing EV adoption and meeting the needs of early adopting customers. The Pilot is meant to be an easy to understand and foundational experience for current and potential fleet and public EV customers. The Pilot is designed to allow customers to adapt to the EV charging technology. It will also allow Minnesota Power to learn more about the costs to serve these customers. Minnesota Power respectfully requests that the Commission approve its Electric Vehicle Commercial Charging Rate Pilot as proposed.

Dated: May 16, 2019

Respectfully submitted,

Jenna Warmuth
Senior Public Policy Advisor
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3448
jwarmuth@mnpower.com

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

RATE CODES

29EV

APPLICATION

Available while this Pilot Program is in effect, to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$12.00
Demand Charge for On-Peak kW	$6.50
Energy Charge for all kWh	7.619¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer’s contract.

Plus any applicable Adjustments.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.350¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

3. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

4. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

5. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. All other hours are considered to be Off-Peak periods, and there is no Demand Charge applied during these times.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the Demand Charge exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the Demand Charge, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

Jodi Nash, of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 16th day of May, 2019 she served Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on the attached Service List were served as requested.

____

Jodi Nash

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_17-879_Official
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_17-879_Official
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_17-879_Official
Thomas	Ashley	tom@greenlots.com	Greenlots	N/A	Electronic Service	No	OFF_SL_17-879_Official
Max	Baumhefner	MBAUMHEFNER@NRDC.ORG	Natural Resources Defense Council	111 Sutter St 21st Fl San Francisco, CA 94104	Electronic Service	No	OFF_SL_17-879_Official
Katie	Bell	ksheldon@tesla.com	Tesla	6801 Washington Ave S #110 Eden Prairie, MN 55439	Electronic Service	No	OFF_SL_17-879_Official
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_17-879_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_17-879_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Corey	Conover	corey.conover@minneapolismn.gov	Minneapolis City Attorney	350 S. Fifth Street City Hall, Room 210 Minneapolis, MN 554022453	Electronic Service	No	OFF_SL_17-879_Official
Heidi	Corcoran	Heidi.Corcoran@CO.DAKOTA.MN.US	Dakota County	N/A	Electronic Service	No	OFF_SL_17-879_Official
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_17-879_Official
Frances	Crotty	Fran.Crotty@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd St. Paul, MN 55155	Electronic Service	No	OFF_SL_17-879_Official
Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_17-879_Official
James C.	Erickson	jericksonkbc@gmail.com	Kelly Bay Consulting	17 Quechee St Superior, WI 54880-4421	Electronic Service	No	OFF_SL_17-879_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_17-879_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_17-879_Official
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_17-879_Official
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Shane	Henriksen	shane.henriksen@enbridge.com	Enbridge Energy Company, Inc.	1409 Hammond Ave FL 2 Superior, WI 54880	Electronic Service	No	OFF_SL_17-879_Official
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_17-879_Official
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
Julia	Jazynka	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_17-879_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_17-879_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Brendan	Jordan	bjordan@gpisd.net	Great Plains Institute	2801 21st Ave S., Suite 220 Minneapolis, MN 55407	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_17-879_Official
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_17-879_Official
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_17-879_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_17-879_Official
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_17-879_Official
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_17-879_Official
Nick	Mark	nick.mark@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_17-879_Official
Kevin	Miller	kevin.miller@chargepoint.com	ChargePoint, Inc.	254 E. Hacienda Avenue Campbell, California 95008	Electronic Service	No	OFF_SL_17-879_Official
Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_17-879_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_17-879_Official
Michael	Noble	noble@fresh-energy.org	Fresh Energy	Hamm Bldg., Suite 220 408 St. Peter Street St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Debra	Opatz	dopatz@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_17-879_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_17-879_Official
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power	30 W Superior S Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_17-879_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_17-879_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	OFF_SL_17-879_Official
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official
Inga	Schuchard	ischuchard@larkinhoffman.com	Larkin Hoffman	8300 Norman Center Drive Suite 1000 Minneapolis, MN 55437	Electronic Service	No	OFF_SL_17-879_Official
Zeviel	Simpser	zsimpser@briggs.com	Briggs and Morgan PA	2200 IDS Center80 South Eighth Street Minneapolis, MN 554022157	Electronic Service	No	OFF_SL_17-879_Official
Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.	254 E Hacienda Ave Campbell, CA 95008	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Byron E.	Starns	byron.starns@stinson.com	Stinson Leonard Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_17-879_Official
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_17-879_Official
Karen	Turnboom	karen.turnboom@versoco.com	Verso Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_17-879_Official
Andrew	Twite	twite@fresh-energy.org	Fresh Energy	408 St. Peter Street, Ste. 220 St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Darrell	Washington	darrell.washington@state.mn.us	DOT	N/A	Electronic Service	No	OFF_SL_17-879_Official
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_17-879_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	OFF_SL_17-879_Official
Patrick	Zomer	Patrick.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	)
Application of Duke Energy Progress,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Service	)
in North Carolina	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-8

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minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

February 26, 2020

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Ste 350
St. Paul, MN 55101

Re: In the Matter of Minnesota Power's Docket No. Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot
Docket No. E015/M-19-337

Dear Mr. Seuffert:

Minnesota Power ("Company") submits the enclosed Corrected Compliance Filing in pursuant to the Minnesota Public Utilities Commission's ("Commission") December 12, 2019 Order in the above-referenced Docket. The February 24, 2020 Tariff page did not have the correct energy charge.

If you have any questions regarding this filing, please contact me at (218) 723-3963 or dmoeller@allete.com.

Yours truly,

David R. Moeller

David R. Moeller
Senior Attorney and
Director of Regulatory Compliance

DRM:sr
Attach.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

RATE CODES

29EV

APPLICATION

Available while this Pilot Program is in effect, to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$12.00
Demand Charge for On-Peak kW	$6.50
Energy Charge for all kWh	5.423~~7.619~~¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.350¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

There shall also be added an Interim Rate Adjustment equal to 5.80% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the ~~Pilot~~ Rider for Customer Affordability of Residential Electricity (CARE).

~~6.~~7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

~~7.~~8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 3:00 p.m.~~8:00 a.m.~~ to 8:00~~10:00~~ p.m., Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m., Monday through Friday, inclusive, excluding holidays. Off-Peak shall be ~~A~~all other hours other than On-Peak or Super Off-Peak~~are considered to be Off-Peak periods~~. There shall be ~~, and there is~~ no Demand Charge applied during Off-Peak or Super Off-Peak hours~~these times~~.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the Demand Charge exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the Demand Charge, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

RATE CODES

29EV

APPLICATION

Available while this Pilot Program is in effect, to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

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RATE (Monthly)

Service Charge	\$12.00
Demand Charge for On-Peak kW	\$6.50
Energy Charge for all kWh	5.423¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than \$25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer’s contract.

Plus any applicable Adjustments.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

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High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

There shall also be added an Interim Rate Adjustment equal to 5.80% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m., Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m., Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak. There shall be no Demand Charge applied during Off-Peak or Super Off-Peak hours.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the Demand Charge exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the Demand Charge, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
E-FILING AND
FIRST CLASS MAIL

SUSAN ROMANS of the City of Duluth, County of St. Louis, State of Minnesota, says that on the **26th** day of **February, 2020**, she served Minnesota Power's Corrected Compliance Filing in **Docket No. E015/RP-19-337** on the Minnesota Public Utilities Commission and the Office of Energy Security via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

Susan Romans

Susan Romans

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	**)**
Application of Duke Energy Progress,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-9

PUGET SOUND ENERGY
Electric Tariff G

SCHEDULE 26
LARGE DEMAND GENERAL SERVICE

(Secondary Voltage or at available Primary distribution Voltage)
(Single phase or three phase where available)(Demand Greater than 350 kW)

1. **AVAILABILITY:**
   1. This schedule is available to any Customer for general electric energy requirements other than Residential Service (as defined in Paragraph 1 of Schedule 7) and whose estimated or actual Demand is greater than 350 kW.
   2. Customers taking service at Secondary Voltage and whose Billing Demand is 350 kW or below for eleven (11) of the most recent 12 consecutive months are not eligible for service under this schedule.
   3. Deliveries at Secondary voltage at more than one point will be separately metered and billed. Deliveries at Primary voltage to a Customer will be at one Point of Delivery for all service to that Customer on contiguous property.
   4. Single-phase motors rated greater than 7-1/2 HP shall not be served under this schedule except by the express written approval of the Company.
   5. Highly intermittent loads, such as welders, X-ray machines, elevators, and similar loads that may cause undue lighting fluctuation, shall not be served under this schedule unless approved by the Company.
   6. For service at Primary voltage, all necessary wiring, transformers, switches, cut-outs and protection equipment beyond the Point of Delivery shall be provided, installed and maintained by the Customer, and such service facilities shall be of types and characteristics acceptable to the Company. The entire service installation, protection coordination, and the balance of the load between phases shall be approved by Company engineers.
2. **MONTHLY RATE – SECONDARY VOLTAGE:**

Basic Charge:	$~~105.74~~111.83			(I)
Demand Charge:	OCT-MAR	APR-SEP		
	$~~11.91~~12.60	$~~7.94~~8.40	per kW of	(I) (I)
Billing Demand				I
Energy Charge:	$0.~~057181~~ 060459 per kWh			(I)
Reactive Power Charge:	$0.~~00126~~ 00133 per reactive kilovolt ampere-hour (kvarh)			

3. **ADJUSTMENTS TO SECONDARY VOLTAGE RATES FOR DELIVERY AT PRIMARY VOLTAGE:** (I)

Basic Charge:	$~~237.92~~258.23 in addition to Secondary voltage rate	I
Demand Charge:	$0.~~39~~ 22 credit per kW to all Demand rates	(I)
Energy Charge:	~~3.94~~2.10% reduction to all Energy and Reactive Power Charges	

4. **ADJUSTMENTS:** Rates in this schedule are subject to adjustment by such other schedules in this tariff as may apply.

PUGET SOUND ENERGY
Electric Tariff G

SCHEDULE 26 (N)
LARGE DEMAND GENERAL SERVICE (Continued)
(Secondary Voltage or at available Primary distribution Voltage)
(Single phase or three phase where available)(Demand Greater than 350 kW)

8. **CONJUNCTIVE DEMAND SERVICE OPTION:**
   a. The Conjunctive Demand Service Option (CDSO) is limited to nine (9) Customers taking Electric Service under this schedule. Each Customer must have at least two (2) but no more than five (5) Points of Delivery participating in this limited optional service. The total retail load served under this limited optional service (under both Schedule 26 and Schedule 31) is limited to 20 average megawatts. Customer Points of Delivery dedicated to electrified transportation are not limited with respect to number of Points of Delivery participating, nor size. Participating Points of Delivery must have begun taking Electric Service prior to January 1, 2018.
   b. Eligible Customers must have appropriate metering available for the participating Points of Delivery, as determined solely by the Company. Customer agrees that all participating Points of Delivery will be billed on the same billing cycle. This limited optional service is available beginning on or after January 1, 2021, starting with the first billing cycle of the participating Customer; and ending on the last billing cycle in December 2026. Participation is limited to a first-come, first-served basis. Customers may request potential participation in this limited optional service beginning at 8:00 a.m. July 1, 2020. Each Customer's participating load, at the time of requesting potential service, must not exceed 2 MW (of winter demand).
   c. Monthly Basic Charges, Energy Charges and Reactive Power Charges will be the same as noted in Sections 2 and 3 of this schedule. The Customer will pay a Delivery Demand Charge as noted in Section 8 of this schedule, in addition to the Conjunctive Maximum Demand Charge.
   d. The Conjunctive Maximum Demand will be determined by summing the Billing Demand metered at each of the Points of Delivery in each hour interval and then selecting the highest summation for the synchronized billing cycle. Should any meter fail to register correctly the amount of demand used by the Customer, the amount of such demand will be estimated by the Company from the best available information.

   e. **MONTHLY RATE – SECONDARY VOLTAGE:**

   Delivery Demand Charge:

OCT-MAR	APR-SEP	
$7.85	$5.23	per kW of Billing Demand

   Conjunctive Maximum Demand Charge:

OCT-MAR	APR-SEP	
$4.75	$3.17	per kW of Conjunctive Maximum Demand (N)

Issued: June 20, 2019 **Effective:** July 20, 2019
Advice No.: 2019-25

Issued By Puget Sound Energy

By: Jon Piliaris **Title:** Director, Regulatory Affairs

PUGET SOUND ENERGY
Electric Tariff G

SCHEDULE 31
PRIMARY GENERAL SERVICE

(Single phase or three phase at the available Primary distribution voltage)

1. **AVAILABILITY:** This schedule applies to all service to contiguous property supplied through one meter where:

   1. The Customer requires Primary voltage to operate equipment other than transformers; or

   2. The Customer requires distribution facilities and multiple transformers due to loads being separated by distances that preclude delivery of service at Secondary voltage; or

   3. The load is at a remote or inaccessible location that is not feasible to be served at Secondary voltage from Company facilities.

   4. All necessary wiring, transformers, switches, cut-outs and protection equipment beyond the point of delivery shall be provided, installed and maintained by the Customer, and such service facilities shall be of types and characteristics acceptable to the Company. The entire service installation, protection coordination, and the balance of the load between phases shall be approved by Company engineers.

   5. Facilities that are being served under this schedule as of May 13, 1985, may, at the Customer's option, retain service under this schedule.

2. **MONTHLY RATE:**

   Basic Charge: $~~343.66~~370.06 (I)

   Demand Charge: OCT-MAR APR-SEP
   $~~11.46~~12.34 $~~7.64~~8.23 per kW of Billing (I) (I)
   Demand

   (I)
   Energy Charge: $0.~~055014~~ 059237 per kWh

   (I)
   Reactive Power Charge: $0.~~00107~~ 00115 per reactive kilovolt ampere-hour (kvarh)

SCHEDULE 31 (N)
PRIMARY GENERAL SERVICE (Continued)
(Single phase or three phase at the available Primary distribution voltage)

8. **CONJUNCTIVE DEMAND SERVICE OPTION:**
   a. The Conjunctive Demand Service Option (CDSO) is limited to five (5) Customers taking Electric Service under this schedule. Each Customer must have at least two (2) but no more than five (5) Points of Delivery participating in this limited optional service. The total retail load served under this limited optional service (under both Schedule 26 and Schedule 31) is limited to 20 average megawatts. Customer Points of Delivery dedicated to electrified transportation are not limited with respect to number of Points of Delivery participating, nor size. Participating Points of Delivery must have begun taking Electric Service prior to January 1, 2018.
   b. Eligible Customers must have appropriate metering available for the participating Points of Delivery, as determined solely by the Company. Customer agrees that all participating Points of Delivery will be billed on the same billing cycle. This limited optional service is available beginning on or after January 1, 2021, starting with the first billing cycle of the participating customer; and ending on the last billing cycle in December 2026. Participation is limited to a first-come, first-served basis. Customers may request potential participation in this limited optional service beginning at 8:00 a.m. July 1, 2020. Each Customer's participating load, at the time of requesting potential service, must not exceed 2 MW (of winter demand).
   c. Monthly Basic Charges, Energy Charges and Reactive Power Charges will be the same as noted in Sections 2 and 3 of this schedule. The Customer will pay a Delivery Demand Charge as noted in Section 8 of this schedule, in addition to the Conjunctive Maximum Demand Charge.
   d. The Conjunctive Maximum Demand will be determined by summing the Billing Demand metered at each of the Points of Delivery in each hour interval and then selecting the highest summation for the synchronized billing cycle. Should any meter fail to register correctly the amount of demand used by the Customer, the amount of such demand will be estimated by the Company from the best available information.

   e. **MONTHLY RATE**:

   Delivery Demand Charge:

OCT-MAR	APR-SEP	
$7.99	$5.33	per kW of Billing Demand

   Conjunctive Maximum Demand Charge:

OCT-MAR	APR-SEP	
$4.35	$2.90	per kW of Conjunctive Maximum Demand

(N)