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

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My names is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the North Carolina Sustainable Energy Association ("NCSEA").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("THE COMMISSION")?

A. Yes. I submitted testimony on behalf of NCSEA in Docket No. E-7, Sub 1146 on the Duke Energy Carolinas, LLC's ("DEC") 2017 general rate case application, in Docket No. E-2, Sub 1142 on the Duke Energy Progress, LLC's ("DEP" or "the Company") 2017 general rate case application, and in Docket No. E-7, Sub 1214 on the DEC 2019 general rate case application.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar

Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS RELATES TO THIS PROCEEDING.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in rate design and utility regulation. For example, as part of my current duties overseeing EQ Research's general rate case tracking and regulatory tracking services, I have reviewed dozens of utility rate design proposals and the associated regulatory determinations.

I have submitted testimony before utility regulatory commissions in Colorado, Hawaii, Georgia, New Hampshire, New York, Oklahoma, South Carolina, Texas, Utah, and Virginia as well as to the City Council of New Orleans,

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

on various issues related to clean energy policy, rate design, and cost of service.[2] These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My *curriculum vitae* is attached as **Exhibit JRB-1**. It contains a full list of proceedings where I have submitted testimony and related information such as docket numbers and the subject matter addressed.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY AND HOW IT IS ORGANIZED.

A. The purpose of my testimony is to propose that the Commission direct DEP to establish electric vehicle ("EV") specific rates for both home charging and commercial charging applications. I use the term "EV-specific rates" throughout my testimony to refer to rate options that apply to separately metered EV charging loads to the exclusion of any other loads on the premises. In Section II of my testimony, I discuss in general why EV rates hold benefits for DEP's ratepayers as a whole and general principles for their design. In Section III, I describe the shortcomings in current residential rate options for EV charging and make my residential EV rate proposal. In Section IV, I discuss and make recommendations for non-residential EV rate options. Section V contains my concluding remarks.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. First, I recommend that the Commission direct DEP to, within 60 days of a final order, file separate, targeted EV-specific tariffs for both residential and non-

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

residential dedicated EV charging. These tariffs should reflect core characteristics that are consistent with effective EV rates that I discuss in my testimony. The Commission should allow a comment period on these tariffs but generally seek to expedite their approval and deployment as soon as possible.

Second, I recommend that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements. DEP should be directed to file quarterly reports updating the Commission and parties on deployment status, tariff enrollment, ratepayer savings, system cost savings, and any other information that the Commission deems relevant to support evaluation of the tariffs and their future evolution. If the Commission adopts the recommendation for a comprehensive rate design study made by Public Staff Witness Floyd in DEC's pending rate case, the investigatory docket could become part of this larger review.

Finally, I recommend that any rates established pursuant to a Commission decision remain available, at a minimum, until any successors or replacements are adopted pursuant to the system of Commission review that I recommend. As reflected in my recommendations for non-residential EV-specific rate characteristics, the duration should also reflect the certainty needed for ratepayers that make large investments in higher powered charging equipment such as Direct Current Fast Chargers ("DCFCs").

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that existing Schedule R-TOU be made available for submetered home EV charging with a modest submetering charge in place of the tariffed Basic Facilities Charge ("BFC"). The amount of the submetering charge should consider the incremental costs of the additional metering as well as the impact that the charge would have on cost savings for the EV owner in order to ensure that the additional cost of taking submetered service does not create a barrier to enrollment.

With the exception of not being available for submetered use, Schedule R-TOU already contains several characteristics that are supportive of home EV charging, as follows:

1. Three pricing periods and short duration on-peak periods;
2. A price differential between the off-peak rate and the otherwise applicable flat rate that should be sufficient to produce meaningful bill savings for EV charging, taking into account a modest incremental metering charge and a typical amount of home EV charging; and
3. An off-peak pricing period with a duration of at least eight hours that allows ample time for low voltage charging to produce a battery charge sufficient for a reasonable length trip or commute.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that a rate or rates for submetered and standalone EV charging be established for non-residential ratepayers under a design that features time variation and mitigates the outsized effects that demand charges have on charging costs. More specifically, the rate or rates should:

1. Address the issues presented by demand rates for non-residential EV charging installations by doing one or both of the following: (a) modifying Schedule SGS-TOUE to permit submetering for EV loads and eliminating or relaxing the maximum demand-based availability limitations currently contained in Schedule SGS-TOUE for EV load, or (b) applying a demand charge limit to Schedules SGS-TOU and LGS-TOU that caps demand charges at an implied maximum volumetric rate, or alternatively, a percentage of the ratepayer's monthly bill;
2. Use the otherwise applicable BFC for standalone charging stations and a submetering charge in place of the BFC for charging units located behind an existing meter; and
3. Remain available to participants for ten years from the date of their enrollment in order to provide a reasonable level of investment certainty to prospective equipment owners.

My testimony also discusses two other options for mitigating the punitive effects that demand rates can have on high voltage EV charging equipment owners:

(a) allowing multiple meters serving EV load to be aggregated for the purpose of determining demand charges, and (b) basing demand charges on the sum of daily maximum demand rather than monthly maximum demand. Due to the relatively more novel nature and additional complexity of these options I do not recommend that they be adopted at this time. However, the Commission should consider both as longer-term options as it pursues future refinements.

Q. PLEASE EXPLAIN THE PRACTICE OF SUBMETERING AS REFERRED TO IN YOUR RECOMMENDATIONS.

A. The measurement of EV load as separate from other load located on the same premises can be accomplished with an additional dedicated electricity meter or with a submeter installed between the existing meter and the EV charger. Submetering can be less costly than the installation of a separate revenue grade meter and associated equipment (e.g., a new meter socket, conduit, etc.). The relatively lower costs mitigate the potential for incremental metering costs to become a barrier to enrollment in the rate.

II. RATIONALE AND JUSTIFICATION FOR EV-SPECIFIC RATES

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN AN "EV RATE" AND AN "EV-SPECIFIC RATE" AS YOU USE THE TERMS IN YOUR TESTIMONY.

A. EV-specific rates are a sub-genre of EV rates. As I use the term, an EV rate refers to any rate that is applicable only to ratepayers with an EV charging load. An EV-specific rate refers to a rate that is applied exclusively to EV charging load as opposed to any other electric load that exists on a premises. An EV-specific rate requires the EV load to be separately measured. Both types of rates may have a place in supporting transportation electrification, but EV-specific rates have the potential to be more targeted so as to take advantage of the unique usage patterns and flexibility that characterize EV loads relative to whole home or building loads.

Q. PLEASE ELABORATE ON THE MERITS OF EV-SPECIFIC RATES RELATIVE TO EV RATES AND THE IDEA OF "TARGETING" WITHIN EV-SPECIFIC RATES.

A. The merits of EV-specific rates and targeting are best illustrated by examples. For instance, a declining block whole home rate that is available only for ratepayers with an EV qualifies as an EV rate and could potentially reduce costs for EV owners and support EV adoption. However, it would not take advantage of ratepayers' ability to manage their charging behavior in a manner that reflects the time-varying costs of electric service.

Furthermore, within the definition I use for an EV-specific rate is a further sub-genre of rates that are *specifically designed* to take *full* advantage of the unique attributes of EV load (i.e., targeted EV-specific rates). For instance, a generally available time-varying rate that can be used for submetered EV load is an EV-specific rate. However, such a rate may display characteristics such as simplified peak and off-peak windows and/or minimal rate spreads that reflect the challenges of managing whole home or whole building use. This fails to take advantage of relatively greater flexibility and controllability of home EV charging relative to other loads. Alternatively, a non-residential rate adapted for EV submetering may still reflect a pass-through of more generally deployed rate designs such as demand-based charges in a way that creates barriers for EV charging.

Q. WHY WOULD THE DEPLOYMENT OF EV RATES BE BENEFICIAL TO THE STATE OF NORTH CAROLINA AND DEP RATEPAYERS?

A. There are several reasons. First, well-designed EV rates encourage EV owners to charge their vehicles during off-peak times. Off-peak charging helps mitigate the potential that growing EV load could exacerbate peak demands and create additional costs, and in doing so can improve system load factor. Second, EV-specific rates could potentially be used to help mitigate “duck curve” issues that can arise due to the combination of low loads and high solar generation during some parts of the year. This can play a role in avoiding renewables curtailment and more generally concentrating load at times of low marginal greenhouse gas emissions.

Well-designed EV rates also produce cost savings for EV owners relative to what they might otherwise pay under a standard rate. Cost savings are directly beneficial to EV owners and could also be seen as a generally fairer outcome under circumstances where a large portion of EV charging is expected to occur during off-peak hours anyway due to EV owners' work and personal schedules. Finally, potential cost savings are an important consideration for ratepayers considering purchasing an EV or installing charging equipment. The development of greater charging accessibility is a critical element in transportation electrification. In turn, EV rates are an important element in increasing the availability of cost-effective charging options in homes, and perhaps even more importantly, in public settings.

Ultimately, strategic use of rate structure can be a more scalable support mechanism for EV deployment than "programmatic" solutions, which tend to be inherently limited in size. Programmatic solutions certainly still have a place in transportation electrification, such as targeting specific sectors or barriers. Rate structure, on the other hand, is a critical tool for transforming the broader market.

Q. HOW DOES NORTH CAROLINA POLICY ADDRESS TRANSPORTATION ELECTRIFICATION?

A. North Carolina has not established any statutory mandates or guidance on transportation electrification. However, the North Carolina Clean Energy Plan stemming from Executive Order 80 (2018) ("EO 80") recommends that utilities be required to develop innovative rate design pilots for EVs to encourage off-peak charging and test the effectiveness of different rate structures at shifting energy usage.[3] EO 80 itself sets a goal of achieving 80,000 registered zero-emission vehicles in the state by 2025.[4]

Q. IS IT NECESSARY FOR THE COMPANY TO CONDUCT FURTHER STUDY OF CHARGING BEHAVIOR BEFORE DEPLOYING EV-SPECIFIC RATES?

A. No. The charging behavior of EV owners under a generally applicable pricing regime would not be representative of their charging behavior under a well-designed EV rate. If one makes the reasonable assumption that EV charging will in the future take place principally, or even entirely, under time-varying rate designs, an analysis of EV charging under traditional rates that are not designed for EV charging is not predictive of the long-term impacts of EV charging.

Q. WOULD IT MAKE SENSE TO DELAY ADOPTING EV RATES IN ORDER TO STUDY EV CHARGING BEHAVIOR UNDER TRADITIONAL RATES?

No, delaying analysis of charging behavior under rates designed specifically for EV charging while studying charging behavior under traditional rates would only delay the results of a comparative analysis. There is no reason why both sets of evaluations could not be undertaken concurrently if the goal is to reach conclusions on the effects that rate design has on EV charging behavior.

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[3] North Carolina Clean Energy Plan. October 2019. p. 137. Available at: https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf

[4] N.C. Exec. Order No. 80 (October 29, 2018), https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf.

Q. IN DOCKET NO. E-7, SUB 1214, DEC'S GENERAL RATE CASE, PUBLIC STAFF WITNESS FLOYD RECOMMENDED THAT THE COMMISSION ORDER A COMPREHENSIVE RATE DESIGN STUDY TO ADDRESS MANY RATE MODERNIZATION ISSUES, INCLUDING EV RATES. DO YOU AGREE WITH THIS RECOMMENDATION IN THE CONTEXT OF EV RATE DEPLOYMENT IN DEP'S SERVICE TERRITORY?

A. I agree with Witness Floyd that a comprehensive rate design study would be worthwhile, and also that it would be a "lengthy undertaking" that "takes a significant amount of time to develop, as well as to implement."[5] While it is not clear to me what sort of timeline Witness Floyd envisions for the deployment of new rate options, I do not think that conducting a lengthy, all-encompassing study is necessary or advisable prior to making EV-specific rates available in some form. To the extent that Witness Floyd's recommendation would result in such a delay, I respectfully disagree with that aspect.

Q. PLEASE ELABORATE ON WHY AN EXTENDED STUDY PERIOD IS NOT NECESSARY OR ADVISABLE AS A PRECURSOR TO EV RATE DEPLOYMENT.

A. My concern is that such a study and associated stakeholder processes could easily extend several years. By that point, North Carolina is likely to be well behind the curve with respect to EV rate and infrastructure deployment, to the detriment of the

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[5] *Testimony of Jack L. Floyd on Behalf of the Public Staff – North Carolina Utilities Commission*, p. 24, ll. 9-18, Docket No. E-7, Sub 1214 (February 18, 2020).

potential near-term benefits to ratepayers and achieving the EO 80 goal of 80,000 zero-emission vehicles by 2025.

In addition, while an extended study process is appropriate for considering an overarching re-design of DEP's and DEC's respective rates, it is not necessary for the deployment of EV-specific rates because the shortcomings of current rate options are very basic and do not raise the same issues as a broader re-design of rates. For home charging, the basic problem is that customers do not have access to a time-varying rate option that does not require them to take whole home time-varying service. For non-residential charging, the basic problem is the outsized impacts that demand charges have on the cost of EV charging, in particular DCFC. Both issues can be mitigated in the near term through relatively simple changes. I discuss these issues and my recommended near-term solutions in more detail in subsequent sections of my testimony.

Finally, a broader re-design of rates that is undertaken to establish durable solutions would benefit from the information gleaned from the deployment of EV-specific rates in the near term. As I observed previously, at present we lack data on EV charging behavior under EV-specific rates in DEP's (and DEC's) service territories. While considerable insight can be gleaned from evaluating the results of studies performed in other jurisdictions, more recent and more targeted data certainly would not hurt for the purpose of refining EV rate options.

Q. HOW SHOULD THE COMMISSION VIEW REVENUE AND COST IMPACTS AND THE POSSIBILITY FOR CROSS-SUBSIDIES TO OCCUR?

A. The averaging nature of rates ensures that intra-class subsidies will exist within any rate. Under averaged rates, no ratepayer pays their exact cost of service, even if that amount could be determined with precision. The same is true for inter-class cost of service relationships. Furthermore, when designing rates that target a specific type of new load and seek to direct ratepayer behavior, it is unavoidable that mismatches will occur between costs and revenue and the distribution of both among ratepayers as a whole.

While such issues bear attention, the magnitude of EV load at present and in the near future is small relative to other loads. As a consequence, the scale of any mismatches that do exist is bound to be small as well. In any case, it is not possible to know how costs and revenue align without the information gleaned from deployment and evaluation of EV rates. Class averages that might be applied to make a whole-site load rate theoretically revenue neutral cannot be applied to new EV load. In addition, as I previously observed, charging behavior under traditional rates is not an accurate predictor of charging behavior under an EV rate. Ultimately, revenue and cost distribution uncertainties are unavoidable, and they should not function as a pretext for delaying the deployment of EV-specific rates. Allowing them to do so amounts to creating a Catch-22 where assembling the information on which to base future decisions is prevented by a failure to establish means by which the information can be gathered.

Q. GIVEN THESE UNCERTAINTIES, HOW SHOULD THE COMMISSION ATTEMPT TO ENSURE THAT EV-SPECIFIC RATES ARE LIKELY TO BENEFIT RATEPAYERS AS A WHOLE?

A. The design of EV-specific rates should have a solid foundation in time-varying marginal costs in recognition of the fact that new EV load, if well-managed, need not contribute to additional costs driven by peak demands. It is my understanding that DEP does not study the marginal costs of transmission and distribution. However, the pricing periods in existing rates, and in Schedule PP,[6] reflect the time-varying nature of energy and capacity costs and can serve as a guide for defining higher cost and lower cost time periods. For instance, transmission costs are driven by the same system-wide peak demands as generation capacity costs, even if a marginal transmission cost is not studied itself. As long as the pricing periods for an EV-specific rate are generally aligned with established pricing periods, they should be aligned with the additional costs of EV charging at different times. From the standpoint of new load, as long as the rate a ratepayer pays is at or above the marginal cost, other ratepayers are indifferent or accrue benefits.

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[6] Schedule PP contains time-varying rates for the purchase of energy and capacity from small power production facilities. Those pricing periods have been updated more recently than the pricing periods used for existing time-varying retail rates.

III. RESIDENTIAL EV RATE OPTION

Q. WHY ARE EV-SPECIFIC RATES IMPORTANT FOR RESIDENTIAL RATEPAYERS?

A. Viable home charging options are important for residential EV owners because the vast majority of residential EV charging occurs at home. A 2015 study by the Idaho National Laboratory examined the charging habits of Americans, and found that a typical driver charges their EV at home 84-87% of the time.[7] While it is plausible, and even likely, that the availability of public or workplace charging options could diminish the amount of home charging, it is difficult to envision any near-term scenario where home charging does not comprise a large portion of residential EV charging. Home charging is simply highly convenient and likely to remain so.

Q. DOES DEP CURRENTLY OFFER AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS?

A. No.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS IN THIS RATE CASE?

A. No.

[7] Idaho National Laboratory, "Plugged In: How Americans Charge Their Electric Vehicles," 2015. Available at: https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS IN ANY OTHER FORUM?

A. No. DEP's transportation electrification proposal includes proposed tariffs for each EV pilot program, but it does not propose new residential rate designs for EV charging as a component of these tariffs. For example, the Residential EV Charging Program tariff would provide certain incentives for residential Level 2 EV charging, but usage would still be "billed under the applicable residential schedule." These tariffs would also be limited to the size and duration of the EV pilot programs.[8]

Q. WHAT RATE OPTIONS ARE CURRENTLY AVAILABLE FOR A PROSPECTIVE RESIDENTIAL EV OWNER?

A. DEP's residential ratepayers can choose from several rate schedules. The generally-available rate options and their basic rate designs are as follows:

- Schedule RES – Includes a monthly BFC and flat seasonal energy charges with a slightly lower rate during winter months.
- Schedule R-TOU – Includes a monthly BFC and seasonal time-varying energy charges under a three-period design (on-peak, shoulder, and off-peak), with fairly sizable rate spreads between rates for each pricing period.

[8] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Application for Approval of Proposed Electric Transportation Pilot*, Docket Nos. E-2, Sub 1197 and E-7, Sub 1195 (March 29, 2019).

- Schedule R-TOUD – Includes a monthly BFC, seasonal on-peak demand rates, and time-varying energy charges with a modest rate spread between peak and off-peak rates under a two-pricing period design (on-peak and off-peak).

Q. WHAT FACTORS ARE IMPORTANT FOR DESIGNING EV-SPECIFIC RATES THAT ENCOURAGE RESIDENTIAL ENROLLMENT?

A. Both the price differential between peak and off-peak rates, as well as the duration of off-peak period windows are important for encouraging residential EV owner enrollment. The price differential refers to the difference between the applicable rate for off-peak usage compared to the applicable rate for on-peak usage, and can also be expressed as a ratio. The price differential or ratio needs to be sufficiently large to result in meaningful changes in ratepayer charging behavior. The larger the price differential, the more the ratepayer is incentivized to conduct EV charging during off-peak periods and avoid charging during on-peak periods.

A 2018 presentation from the Brattle Group summarizing residential EV rate options from U.S. utilities indicates the median summer season price ratio is greater than 3:1 and the median winter season price ratio is well above 2:1, with larger average price ratios for three-period TOU rates compared to two-period TOU rates. When comparing the peak rate to the lowest available off-peak rate, the median price differential for the summer season is $0.17/kWh for two-period TOU rates and $0.28/kWh for three-period TOU rates. Price differentials are lower during the winter season, averaging $0.09/kWh and $0.12/kWh for two-period and three-or-more-period TOU rates.[9] A more recent report from the Smart Electric Power Alliance ("SEPA") shows a median differential ratio of 3.6:1 and a median price differential of $0.20/kWh.[10]

The duration of the peak and off-peak windows is also important because EV owners must have an off-peak charging window that is long enough achieve a sufficient charge for commutes or normal daily driving. A common rate design for residential EV-specific rates is to incorporate an off-peak window that allows EV charging to occur overnight, allowing residential EV owners to charge their vehicle in advance of a morning commute. Nearly all residential EV rates use an off-peak charging window of at least six hours. The median off-peak window for residential EV-specific rates is 8 hours for both the summer and winter seasons, although some rates have off-peak periods for up to 16 hours.[11]

The charging duration necessary for an individual EV owner depends on the ratepayer's driving needs, charging equipment, and access to charging outside of the home. Table 1 shows the broad characteristics of different types of EV charging equipment.

[9] Ahmad Faruqui, Ryan Hledik, and John Higham. "The State of Electric Vehicle Home Charging Rates." October 15, 2018. Attached as **Exhibit JRB-2**.
[10] SEPA. "Residential Electric Vehicle Rates that Work." November 2019. Attached as **Exhibit JRB-3**.
[11] **Exhibit JRB-2**. The rates used to develop these statistics appear to include a significant percentage of rates that apply to the entire residence. The survey includes 31 unique rate offerings, 18 of which are whole home rates, 8 of which are exclusively for EV charging, and 5 of which can be used either on a whole home or EV-specific basis.

Table 1: Types of EV Chargers[12]

Type	Voltage (V)	Capacity (kW)	Minutes to Supply 80 Miles of Range
Level 1	120 V	1.4 - 1.9	630 - 860
Level 2	240 V	3.4 - 20	60 - 350
Level 3 (DCFC)	480 V	50 - 400	3 - 24

The added charging speed associated with Level 2 charging comes at a cost in terms of the price of the charging equipment, and any possible electric upgrades necessary to accommodate the additional load. The price differential is critical for producing ratepayer savings that can help offset incremental EV costs and the costs of higher capacity charging equipment.

Q. WHAT ARE THE MERITS OF A RATE DESIGN WITH THREE PRICING PERIODS RELATIVE TO ONE WITH ONLY TWO PRICING PERIODS?

A. Greater granularity of pricing periods provides a more accurate reflection of the time-varying nature of the cost of electric service. In particular, a three-period rate design typically enables shorter duration peak periods that correspond to hours of particularly high demand. The relative flexibility and controllability of EV loads lends itself to a more complex rate design than what might be attractive to customers if applied to whole home or whole building loads.

In the context of EV charging, shorter duration peak periods help avoid circumstances where a small amount of non-off-peak charging produces an

[12] Garrett Fitzgerald and Chris Nelder. "From Gas to Grid: Building Charging Infrastructure to Power Electric Vehicle Demand." Rocky Mountain Institute, 2017. p. 33. Available at: https://rmi.org/wp-content/uploads/2017/10/RMI-From-Gas-To-Grid.pdf. Attached as **Exhibit JRB-4**.

incremental cost increase that offsets the cost savings of a much larger amount of off-peak charging. This phenomenon is highly pronounced for rates with a demand component, but can also be present under fully volumetric rates if the difference between an otherwise applicable flat rate and the on-peak rate is significantly larger than the difference between the flat rate and the off-peak rate. A shorter duration peak period makes it easier to avoid peak charges even if an EV owner occasionally needs to charge a vehicle during non-off-peak hours (*e.g.,* during the daytime). A mid-peak or shoulder rate applicable to periods of intermediate demand can send a moderated price signal that avoids significantly rewarding or penalizing charging that takes place during medium demand periods.[13]

Q. IS IT IDEAL FOR RATEPAYERS WITH EVS TO CHARGE THEIR VEHICLES ONLY DURING OFF-PEAK PERIODS?

A. Of course it is, but that may not be practical for all EV owners at all times. EV charging loads can be highly flexible, but that does not make them infinitely flexible. From time to time, an EV owner may need to charge their vehicle during peak periods. For instance, a 2018 report by Synapse Energy Economics ("Synapse") notes that EV-specific rates offered by California investor-owned utilities ("IOUs") have been highly successful at encouraging off-peak charging, but not 100% successful. Synapse's analysis showed that 93% of charging on occurred during off-peak hours for Pacific Gas and Electric's EV-specific rate

[13] Depending on the underlying cost structure and pricing period design, the "middle" pricing period could have a small premium or a small discount relative to a flat rate. The shoulder rates in DEP Schedule R-TOU have a small premium relative to the flat rate under Schedule RES.

while 88% percent of charging is off-peak on Southern California Edison's EV-specific rate.[14]

EV rates should encourage EV owners to charge during off-peak times, but the risk-reward relationship must be balanced and consistent. A rate that is not forgiving of occasional departures from the ideal makes perfect the enemy of the very good. Rates with demand components such as Schedule R-TOUD do not provide this balance.

Q. ARE THESE EXISTING RATE OPTIONS WELL-SUITED FOR RESIDENTIAL EV HOME CHARGING?

A. No. Schedule RES features flat energy charges and as a consequence fail to take advantage of the potential for managed charging. Schedule R-TOU has one major shortcoming: the lack of a submetering option. This is problematic in two ways. First, managing usage behavior for a whole home is far more complex than doing so for a single, and theoretically highly flexible, EV load. Second, the BFC for Schedule R-TOU is $16.85/month, which is $2.85/month higher than the BFC for Schedule RES. The higher BFC diminishes the potential for a customer to realize cost savings relative to what they would pay under Schedule RES.

Schedule R-TOUD has the same shortcoming as Schedule R-TOU (*i.e.,* lack of a submetering option and a higher BFC than Schedule RES), but also has two additional features that could make it unattractive for ratepayers with EVs. First,

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[14] Whited, M., Allison, A., and Wilson, R. ("Whited et al.") June 25, 2018. Driving transportation electrification forward in New York: Considerations for effective transportation electrification rate design. p. 2. Cambridge, MA: Synapse Energy Economics. Attached as **Exhibit JRB-5**.

the demand component in Schedule R-TOUD contributes an added level of complexity for a ratepayer that is accustomed to volumetric rates and likely has little or no understanding of demand rates generally, their own demand patterns, and how demand rate service could affect their electric bill. Second, the two-period design contains extended on-peak periods, totaling 11 hours per day from April – September (10 AM – 9 PM) and 12 hours per day from October – March (6 AM – 1 PM and 4 PM – 9 PM.[15]

Q. ARE THERE ANY OTHER RATE DESIGN ELEMENTS ASSOCIATED WITH ESTABLISHING AN EFFECTIVE EV-SPECIFIC RATE FOR HOME CHARGING?

A. Yes. It is reasonable for EV ratepayers to pay for the cost of additional metering required to measure EV charging usage, but any incremental fixed charge associated with the submetered load should be limited to the incremental metering cost. This would be equivalent to how monthly fixed charges were assessed under DEC's now closed rate schedule for submetered controlled water heating (former Schedule WC).

The Commission should be aware that the costs of separate meter and even submetering (to a lesser extent) have been cited as a barrier to some EV-specific home charging rates.[16] However, it is not clear whether submetering costs would present a barrier in North Carolina. At the time of its closure former DEC Schedule

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[15] These on-peak periods are limited to non-holiday weekdays.
[16] *See* **Exhibit JRB-3** and **Exhibit JRB-5** for an additional discussion of metering cost issues and submetering options.

WC had modest submetering charge of $1.71/month, an amount that could easily be offset and exceeded by ratepayer savings even with a relatively moderate price differential between a flat rate and the off-peak rate.

Costs for additional EV load metering among Virginia utilities are slightly higher. Dominion Virginia's Schedule EV contains an additional monthly fixed charge of $2.73/month.[17] Appalachian Power's Schedule PEV uses a different approach, translating the incremental monthly submetering cost to a volumetric rate based on an assumed amount of monthly off-peak charging and adding that amount to the off-peak rate. The submetering cost used in this calculation is $2.37/month.[18]

Q. HOW DO YOU RECOMMEND THAT AN EV RATE BE ESTABLISHED FOR DEP'S RESIDENTIAL CUSTOMERS?

A. I recommend that existing Schedule R-TOU be opened for submetered EV charging, with modest submetering charge. My recommendation is based on the fact that Schedule R-TOU already contains several of the attributes that are important for an effective home charging rate. It has a three-period design with a 5-hour peak period from April – September and a 3-hour peak period from October – March, and long duration off-peak periods that measure 15 hours from April – September and 10 hours from October – March. At the rates proposed by DEP in

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[17] Virginia Electric and Power Company, Schedule EV, *available at* https://www.dominionenergy.com/library/domcom/media/home-and-small-business/rates-and-regulation/residential-rates/virginia/schedule-ev.pdf?la=en&modified=20190401150009.

[18] Virginia State Corporation Commission. Docket No. PUR-2019-00067. *Petition of Appalachian Power Company for approval to implement a voluntary schedule for owners of Personal Electric Vehicles*. Exhibit 2. April 23, 2019, *available at* http://www.scc.virginia.gov/docketsearch/DOCS/4g2w01!.PDF

this proceeding, the off-peak rate from July – October is $0.04262/kWh lower than the flat rate under Schedule RES while from November – June off-peak rate is $0.0366/kWh lower. The off-peak rates, at $0.0837/kWh are considerably higher than the off-peak marginal costs for energy and capacity found in Schedule PP, which are generally approximately $0.03/kWh or less.

Collectively these features would allow an EV owner to accrue meaningful savings for off-peak charging as long as the submetering charge is reasonable, while also producing benefits for other ratepayers because the off-peak retail rate is well above off-peak marginal costs. Table 2 shows estimated savings under proposed rates with sensitivities total monthly charging, the amount of non-off-peak charging,[19] and the amount of a hypothetical submetering charge.

Table 2: Estimated Customer Savings Under Submetered R-TOU

Monthly Charging (kWh) & Off-Peak %	Annual Gross Savings ($)	Annual Net Savings ($2.00/month metering charge)	Annual Net Savings ($3.00/month metering charge)
200 (100% off-peak)	$92.66	$68.66	$56.66
200 (90% off-peak)	$61.48	$37.48	$25.48
300 (100% off-peak)	$138.98	$114.98	$102.98
300 (90% off-peak)	$92.22	$68.22	$56.22

[19] The "on-peak" charging rate for the purpose of this estimate is the average of the proposed on-peak and shoulder rates, which would represent 5% on-peak period charging and 5% shoulder period charging.

IV. NON-RESIDENTIAL EV RATE OPTIONS

Q. HOW DO CONSIDERATIONS FOR NON-RESIDENTIAL EV CHARGING RATE OPTIONS DIFFER FROM THOSE FOR RESIDENTIAL CHARGING?

A. The main difference between non-EV rates for residential charging and non-residential non-EV rates is the use of demand charges in non-residential tariffs. Demand charges under standard utility rate schedules for non-residential ratepayers have been repeatedly shown to be the largest barrier to non-residential EV charging, especially DCFC charging.[20] Demand charges assessed for EV charging can easily overwhelm any potential revenue a public EV charging station would generate, or create extraordinarily high costs for charging in non-public applications (e.g., fleet charging or workplace charging). For example, a study by the Rocky Mountain Institute found that demand charges can be responsible for more than 90% of a DCFC ratepayer's electric bill under existing typical utilization rates.[21] While the overall bill impact will be smaller for ratepayers with Level 2 chargers, which have a considerably smaller demand than DCFCs, demand charges can still have a significant impact on these ratepayers' electricity bills under low utilization rates.

[20] *See, e.g.,* David Farnsworth, Jessica Shipley, Joni Sliger, and Jim Lazar. "Beneficial Electrification of Transportation." Regulatory Assistance Project, January 2019; Dane McFarlane, Matt Prorok, Brendan Jordan, and Tam Kemabonta. "Analytical White Paper: Overcoming Barriers to Expanding Fast Charging Infrastructure in the Midcontinent Region." Great Plains Institute, July 2019; Garrett Fitzgerald and Chris Nelder. "EVgo Fleet and Tariff Analysis." Rocky Mountain Institute, 2017, attached as **Exhibit JRB-6**; Garrett Fitzgerald and Chris Nelder. "DCFC Rate Design Study for the Colorado Energy Office." 2019. Rocky Mountain Institute.

[21] **Exhibit JRB-6**.

EV charging stations today tend to have relatively low utilization rates due to the modest adoption of EVs to date, but since EV charging stations have a fixed demand that is based on the type of charger installed, an EV charging station with a low utilization rate still pays the same demand charge as a highly utilized charging station. This creates a "chicken or the egg" problem for EV deployment: widespread DCFC deployment is needed to encourage adoption of EVs, but DCFC infrastructure cannot be affordably deployed until conditions are present that would lead to higher utilization rates of DCFC equipment (i.e., greater EV adoption).

Q. WHY IS IT IMPORTANT TO FOSTER THE GROWTH OF VIABLE NON-RESIDENTIAL CHARGING OPTIONS?

A. It is commonly accepted that a lack of public EV charging infrastructure presents a considerable barrier to the growth of personal EVs, as fast charging enables long distance travel. Separately, public charging options are important for EV owners that live in multi-family dwellings or rely on street parking. Higher capacity charging stations also support fleet electrification for vehicles that have intensive charging needs (e.g., buses). All of these applications are important in the context of broader transportation electrification, hence the need to create near-term bridging mechanisms that address the barrier that demand rates pose for high capacity charging.

Q. DOES DEP CURRENTLY OFFER AN EV-SPECIFIC RATE FOR NON-RESIDENTIAL RATEPAYERS?

A. No.

Q. WHAT RATE SCHEDULES ARE AVAILABLE TO DEP'S NON-RESIDENTIAL RATEPAYERS FOR EV CHARGING?

A. Since DEP does not currently offer any EV-specific rates, generally applicable non-residential rates would apply to all usage for EV charging at a Level 2 or DCFC stations, whether the station is for public charging or restricted use. Non-residential ratepayers can generally choose between a standard rate and a voluntary time-varying rate. The options mapped to customer size are shown below.

Table 3: Current Non-Residential Rate Options

Demand (kW)	Rate Option	Energy Charges	Demand Charges
> 50	SGS	3-tier declining block	None
	SGS-TOUE	3-period TOU, large rate spread	None
	SGS-TOU	2-period TOU, small rate spread	Seasonal on-peak & off-peak excess
50 - 1,000	MGS	Flat	All hour
	SGS-TOU	2-period TOU, small rate spread	Seasonal on-peak & off-peak excess
< 1,000	LGS	Flat	3-tier declining block, all hour
	LGS-TOU	2-period TOU, small rate spread	3-tier seasonal on-peak & off-peak excess, with on-peak declining block

One of the time-varying rates, Schedule SGS-TOUE, is designed in much the same way as Schedule R-TOU rate. Schedule SGS-TOUE would likely not be an option for any ratepayer that installs a DCFC station or for a standalone DCFC station because it is only available to ratepayers with maximum demands of 50 kW or less and a contract demand of 30 kW or less. As shown previously in Table 1 DCFC stations often exceed this demand threshold.[22]

Q. ARE THESE RATE OPTIONS WELL-SUITED TO NON-RESIDENTIAL EV CHARGING?

A. No. Schedule MGS and Schedule LGS do not contain any time variation and Schedule LGS charges higher rates to ratepayers with low load factors. Two of the available time-varying rate options shown in Table 3, SGS-TOU and LGS-TOU, provide the principal time-varying price signal through the on-peak demand component. For both of these rates the on-peak demand charges is determined by monthly maximum demand, which in both cases applies to monthly maximum demand from 10 AM – 10 PM period during April – September (12 hours) and 6 AM – 1 PM and 4 PM – 9 PM during October – March (12 hours). As a consequence, a single instance of on-peak charging during a month would incur a demand charge that drives a ratepayer's bill. The on-peak demand windows would be virtually impossible to avoid entirely.

[22] DCFC stations typically have a charging capacity of 50 kW per charging port and often have multiple ports.

Schedule SGS-TOUE could be attractive for non-residential EV charging but it is not available for submetered use. Furthermore, as noted above it would likely not be available for higher capacity charging units due to the maximum demand limit. Even the addition of a Level 2 charging unit could easily push a non-residential ratepayer beyond that demand threshold and cause the rate to become unavailable for even whole building use.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW DEMAND CHARGES CAN AFFECT THE COST OF EV CHARGING?

A. Yes. Table 4 illustrates the impacts of demand charges based on the proposed rates in DEP Schedules TOU-SGS and MGS on a hypothetical DCFC station with two charging ports that each have a 50 kW demand. It assumes that the units are in use by multiple vehicles at the same time at least once per month, resulting in a 100 kW maximum demand. For the Schedule SGS-TOU example, it is assumed that at least one 100 kW monthly demand is registered during an on-peak period each month.[23]

[23] The calculation uses the average of the summer and winter on-peak demand charge from Schedule SGS-TOU. Off-peak excess demand is assumed to be zero because off-peak demand is never higher than the 100 kW rating for the station itself.

Table 4: Demand Charge Impacts on DCFC Charging Costs

	SGS-TOU	MGS
BFC ($/month)	$35.50	$28.50
Demand Charge ($/kW)	$10.66	$6.72
On-Peak Energy	$0.07100	$0.08068
Off-Peak Energy	$0.05754	$0.08068
Energy/Session (kWh)	50	50
Demand (kW)	100	100
15 Total Sessions/Month, Composed of 14 Off-Peak Sessions and 1 On-Peak Session		
Annual Bill	$13,738	$9,132
Cost/Session	$76.32	$50.73
Cost/kWh	$1.53	$1.01
60 Total Sessions/Month, Composed of 59 Off-Peak Sessions and 1 On-Peak Session		
Annual Bill	$15,292	$11,310
Cost/Session	$21.24	$15.71
Cost/kWh	$0.42	$0.31

Two important details are shown in Table 4. First, even with a relatively high utilization rate of 60 sessions per month (two per day), the cost of charging is still fairly high on a $/kWh basis under both rates. Second, a charging unit owner would be better off under Schedule MGS, which is not time-differentiated, because it has a lower demand charge.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR NON-RESIDENTIAL RATEPAYERS IN THIS RATE CASE?

A. No.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR NON-RESIDENTIAL RATEPAYERS IN ANY OTHER FORUM?

A. Not really. The tariffs associated with the Company's transportation electrification proposal generally refer to existing non-residential rates for the purposes of billing, although DEP does propose a few modest modifications under several pilot programs. The non-residential rate options allow for separately metered EV charging, but not submetering, and either fail to provide time-varying price signals or fail to consider the detrimental effects that the existing rate designs would have on charging costs. For instance, the proposed fleet charging program uses the existing SGS-TOU rate. It requires the customer to pay a full BFC and rates under a design for which the principal price signal is an on-peak demand charge assessed during a long-duration peak window.

For multi-family dwelling and public Level 2 charging services, ratepayers would be charged a Level 2 Charging Fee comprised of the utility's first block energy rate of Schedule SGS, plus $0.02/kWh (*i.e.,* no time differentiation). For DCFC charging, DEP's proposed Fast Charging Fee, to be updated quarterly, only applies to its proposed network of utility-owned and operated DCFCs, and would not be available for usage by third-party-owned DCFCs. The pilot programs are also limited in size and duration, and do not reflect permanent offerings that would result in a sustained incentive for off-peak charging.[24]

[24] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Application for Approval of Proposed Electric Transportation Pilot*, Docket Nos. E-2, Sub 1197 and E-7, Sub 1195 (March 29, 2019).

Q. WHAT RATE OPTIONS ARE AVAILABLE FOR ADDRESSING THE EFFECTS OF DEMAND CHARGES ON OWNERS OF HIGH CAPACITY EV CHARGING STATIONS?

A. There are several options as follows:

1. Substitution of time-varying volumetric charges for demand charge components.
2. Establishing limits or caps on demand charges.
3. Allowing aggregation of multiple meters for the purpose of calculating demand charges.
4. Modifying the calculation of demand charges from being based on monthly maximum demand to the daily maximum demand.

Q. HOW COULD THE SUBSTITUTION OF TIME-VARYING ENERGY CHARGES FOR DEMAND CHARGES BE ACCOMPLISHED IN AN EV-SPECIFIC NON-RESIDENTIAL RATE?

A. The simplest way would be to open Schedule SGS-TOUE to submetered EV charging and eliminate or relax the existing 50 kW monthly demand and 30 kW contract demand limits for submetered EV loads. Like Schedule R-TOU, Schedule SGS-TOUE already features attributes that are supportive of EV charging, making it a reasonable place to start for design of a non-residential EV-specific rate.

As a submetered EV rate option, Schedule SGS-TOUE would feature a submetering charge if the EV load is located behind an existing whole building meter, or the otherwise applicable BFC under either Schedule SGS-TOUE or

Schedule SGS-TOU for standalone charging installations. The Schedule SGS-TOU BFC would apply for larger capacity installations that would otherwise only qualify for Schedule SGS-TOU. An increase in the demand limit for submetered EV load could correspond to the 1,000 kW threshold used in Schedule SGS-TOU.

Q. ARE THERE EXAMPLES OF NON-RESIDENTIAL EV-SPECIFIC RATES THAT FEATURE A SIMILAR USE OF VOLUMETRIC RATHER THAN DEMAND CHARGES?

A. Yes. There are several examples of this general design feature, with variations based on the state and utility. In some, but not all cases, the substitution is subject to a specific term and/or phase-out system. This kind of feature provides predictability for charging station owners, helps mitigates cross-subsidization concerns, and reflects an expectation that the impacts of demand charges will be reduced by higher utilization rates in the future. Below are several examples illustrating this model. The examples below should not be viewed as an exhaustive list.

- California (SCE): Southern California Edison ("SCE") offers rates under Schedules TOU-EV-7 through TOU-EV-9 for separately metered EV charging stations with different load sizes (e.g., TOU-EV-8 applies to loads from 20 kW – 500 kW). The rates offer a demand charge free rate for five years (from March 1, 2019 through March 1, 2024), followed by the phase-in of a modest demand charge over the following five years for the TOU-EV-8 and TOU-EV-9 rate schedules. Customers on Schedule TOU-EV-7 (demand of less than 20 kW) retain an energy-only option. Time-varying volumetric energy charges are increased to recover costs that would otherwise be recovered in the demand charge.[25]

- Connecticut (Eversource): Eversource Energy's Electrical Vehicle Rate Rider allows separately metered public charging stations to pay energy charges in place of any otherwise applicable demand rate that would apply under the standard general service rate schedules. The energy charge is determined by the average rate for that rate component. This rider does not have a sunset or phase-out clause.[26]
- Nevada (Nevada Power Company & Sierra Pacific Power Company): Both utilities offer Schedule EVCCR-TOU to customers under the larger commercial rate schedules that install separately metered DCFC stations. The rates offer at ten-year discount schedule under which demand rates are reduced by 100% in the first year (starting April 1, 2019) and the discount declines by 10% each year thereafter to zero after the tenth year (starting April 1, 2029). Customers pay a substitute transition energy charge in place of the demand charges.[27] [28]

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[25] *See e.g.,* SCE Schedule TOU-EV-8. Available at: https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/general-service-&-industrial-rates/ELECTRIC_SCHEDULES_TOU-EV-8.pdf.

[26] Eversource Connecticut. Electric Vehicle Rate Rider. Available at: https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/ev-rate-rider.pdf?sfvrsn=e44ca62_0.

[27] Nevada Power Company. Schedule EVCCR-TOU. Available at: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-south/EVCCR-TOU_South.pdf

[28] Sierra Pacific Power Company. Schedule EVCCR-TOU. Available at: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-north/EVCCR-TOU_Electric_North.pdf.

- Pennsylvania (PECO): PECO Energy Company's Electric Vehicle DCFC Pilot Rider (Schedule EV-FC) applies a five-year discount to billed distribution demand for customers with publicly available or workplace DCFC charging stations. The demand discount is set at 50% of the maximum nameplate capacity of connected DCFCs.[29]

Q. PLEASE DESCRIBE WHAT YOU MEAN BY A DEMAND CHARGE LIMIT OR CAP OPTION.

A. A demand charge cap limits the portion of a ratepayer's monthly bill that is associated with billed demand charges to either a specified percentage of the ratepayer's bill or an implied volumetric rate. Such a rate could be applied more generally as a way to reduce the adverse impacts of demand charges on ratepayers with low load factors. However, in the present context, it more specifically addresses circumstances where EV charging load contributes to demand charges being a very high percentage of a ratepayer's bill due to a low utilization rate and low load factor. A demand charge cap could be deployed as a special condition for ratepayers with under Schedules SGS-TOU or LGS-TOU for ratepayers with EV load (i.e., not separately metered), or it could be reflected in a tariff for dedicated EV charging.

[29] PECO Electric Tariff. Schedule EV-FC at tariff p. 84. Available at: https://www.peco.com/SiteCollectionDocuments/CurrentTariffElec.pdf.

Q. CAN YOU PROVIDE ANY EXAMPLES OF THE DEPLOYMENT OF A DEMAND CHARGE LIMIT OPTION?

A. Yes. In 2019, Minnesota Power received approval to deploy a rate for commercial EV charging that caps demand charges at 30% of a ratepayer's bill. The Order that approved the rate also directed Minnesota Power to establish a three-period time-varying rate design for the commercial EV charging tariff.[30] Minnesota Power's proposal was based in part on an evaluation of six of its customers with on-site EV charging equipment and the effective energy rate those customers paid due to the demand charge. The results of this analysis are shown below in Table 5 followed by the rate that these customers would have paid under the capped demand charge in Table 6. The percentage-based cap produced approximately the same effective energy rate for five of the six customers and only a slightly higher rate for the one remaining customer. The applicable demand rate for this comparison is $6.50/kW of on-peak demand.[31]

[30] Minnesota Public Utilities Commission Docket No. E015/M-19-337. *In the Matter of Minnesota Power's Docket No. Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot.* "Order Approving Pilot with Modifications and Setting Reporting Requirements." December 12, 2019.
[31] Minnesota Public Utilities Commission Docket No. E015/M-19-337. *In the Matter of Minnesota Power's Docket No. Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot.* "Petition for Approval of Electric Vehicle Commercial Charging Rate." p. 13. May 16, 2019.

Table 5: Bills Under Generally Applicable Commercial Rate

Customer	Demand Charge (% of Bill)	Rate Paid ($/kWh)	Percentile Rank (Bill/KWh) Among GSD Customers
1	56%	$0.19	94.80%
2	75%	$0.34	98.80%
3	73%	$0.31	98.70%
4	78%	$0.38	99.10%
5	78%	$0.39	99.10%
6	88%	$0.78	99.70%

Table 6: Bills Under Proposed Commercial EV Rate

Customer	Demand Charge (% of Bill)	Rate Paid ($/kWh)	Percentile Rank (Bill/KWh) Among GSD Customers
1	30%	$0.12	65.50%
2	30%	$0.12	67.00%
3	30%	$0.12	67.70%
4	30%	$0.12	69.70%
5	30%	$0.12	69.80%
6	30%	$0.14	82.70%

I have attached Minnesota Power's application as **Exhibit JRB-7**. Attached **Exhibit JRB-8** contains Minnesota Power's compliance tariff addressing the modifications made by the Minnesota Public Utilities Commission in approving the tariff, most notably shortening the on-peak period from 14 hours to 5 hours.

Incidentally, Duke Energy Kentucky's rates contain a similar limiter. In Duke's Kentucky territory, the generally applicable rate for non-residential service at distribution voltage caps maximum monthly charges, excluding the monthly fixed charge, at a rate of roughly 23.7 cents/kWh. This rate is not specific to EV ratepayers and is available to non-residential ratepayers with demands up to 500 kW.[32]

Q. HOW COULD A DEMAND CHARGE CAP BE SET FOR AN EV-SPECIFIC NON-RESIDENTIAL RATE?

A. One method would be to set the cap as a volumetric rate equivalent or, approximately so, to the rate that a residential ratepayer would pay on flat rate service (*i.e.,* Schedule RES). Since a residential ratepayer has a choice between charging at home or charging at a commercial location, setting the cap in this manner ensures that owners of EV chargers are not effectively paying more than a residential ratepayer would pay to charge an EV at home.

Q. HOW COULD A DEMAND CHARGE LIMIT FOR EV LOAD BE ESTABLISHED IN THE FORM OF A TARIFF?

A. A demand charge limit for dedicated EV charging could be established by modifying Schedules SGS-TOU and LGS-TOU to apply the limit to EV-only loads. For standalone installations, the otherwise applicable BFC would apply. Submetered EV loads behind another meter would incur an incremental submetering charge. I note that this approach would fail to address the long on-peak windows found in Schedules SGS-TOU and LGS-TOU, but it would help mitigate the outsized role that the demand charge plays in determining charging costs.

[32] Duke Energy Kentucky. Rate DS: Service at Secondary Distribution Voltage. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-ky/sheet-no-40-rate-ds-ky-e.pdf?la=en.

Q. PLEASE EXPLAIN THE CONCEPT OF A METER AGGREGATION OPTION FOR THE PURPOSE OF CALCULATING DEMAND CHARGES.

A. Currently, the bills of ratepayers with multiple meters are calculated individually for each meter. For example, a business that has multiple locations within a utility's service territory will pay a separately calculated electricity bill for each location. A policy that allows the aggregation of multiple meters for purposes of calculating demand charges for EV charging would permit these ratepayers to aggregate their demand across all participating locations for the sole purpose of calculating the demand charge. In the context of EV charging, this policy recognizes that a ratepayer with multiple EV charging stations installed across multiple locations could experience diversity with respect to when the charging stations are used. When EV charging station utilization rates are relatively low, and individual metered loads have relatively low load factors, this policy can help reduce the total demand charges paid by a ratepayer with multiple accounts.

It is important to note that this is different from the concept of aggregated billing. Under aggregated billing, a ratepayer's individual charges are combined onto a single bill. In contrast, aggregating meters to calculate demand charges only affects the billing determinant used to calculate demand charges.

Q. ARE THERE EXAMPLES OF UTILITIES PROPOSING TO ALLOW THE AGGREGATION OF MULTIPLE METERS TO ENCOURAGE THE DEPLOYMENT OF EV CHARGING?

A. Yes. As part of its June 2019 rate case filing, Puget Sound Energy ("PSE") in Washington state proposed establishing a five-year Conjunctive Demand Pilot that would allow its Large General Service ratepayers that have accounts in multiple locations to aggregate the demands in the different locations for the purpose of calculating transmission and generation demand charges.[33] Under PSE's proposal, the utility would use the highest hourly interval of demand across a participating ratepayer's multiple accounts during a billing period to calculate billed demand for purposes of recovering power and transmission costs. Distribution costs would still be billed using demands at the ratepayer's individual locations.

In its supporting testimony, PSE noted that "from the perspective of power and transmission cost causation, customers served by PSE through multiple locations look no different to PSE (i.e., have no materially different cost of service) than a single customer with similar load characteristics," yet they could pay more in demand charges than a single customer.[34] PSE expressly justified its proposal as a way to mitigate high demand charges that pose a barrier to EV deployment.[35]

[33] Washington Utilities and Transportation Commission, Docket No. UE-190529.
[34] *Prefiled Direct Testimony of Jon A. Piliaris*, Washington Utilities and Transportation Commission, Docket No. UE-190529 (June 20, 2019).
[35] PSE cited several other examples of utilities that have proposed or implemented such a system in Michigan (Consumers Energy and Detroit Edison) and Minnesota (Northern States Power Company, or Xcel Energy). However, I have not verified the accuracy of these other examples.

PSE's proposed tariffs for implementing the program are attached as **Exhibit JRB-9**.

Q. PLEASE EXPLAIN THE CONCEPT OF A DAILY DEMAND CHARGE.

A. A daily demand charge occupies something of a middle ground between traditional demand charges based on monthly maximum demand and fully volumetric rates. A daily demand charge uses the highest recorded demand each day to calculate charges, either during all hours or during a time-varying demand pricing period. In doing so it reflects an averaged contribution to costs and does not penalize ratepayers for a small number of anomalously high demands. The averaging effect is less than that embodied within a volumetric charge because it derives from peak daily demands whereas a volumetric rate charges a ratepayer based on fully averaged demand across all intervals in a given time period.

Q. HOW COULD A DAILY DEMAND CHARGE DESIGN SUPPORT TRANSPORTATION ELECTRIFICATION?

A. Substituting volumetric charges for demand charges provides the greatest benefit to ratepayers with low load factors. At present, many non-residential EV charging loads have this characteristic. A daily demand charge design could be beneficial to EV charging stations with higher utilization rates and higher load factors because at a certain load factor threshold a ratepayer prefers demand charges to energy charges. Such could be the case for fleet charging, where reasonably predictable charging needs can be managed to consistently cycle vehicles in and out in a way that optimizes the use of charging equipment.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE ESTABLISHMENT OF A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that the Commission direct DEP to deploy a non-residential EV-charging rate under options (1) or (2). Option 1 would accomplish the substitution of energy charges for demand charges by using the fully volumetric time-varying rate design found in Schedule SGS-TOUE. Schedule SGS-TOUE should be modified to allow submetering of EV load, and to eliminate or relax the maximum 30 kW contract demand and 50 kW maximum demand limits for EV load in order to permit high capacity charging. The 1,000 kW demand limit found in SGS-TOU could be applied to separately metered or submetered EV load. Submetered load behind an existing meter would be subject to a submetering charge limited to the cost of the additional metering, while standalone installations would be subject to the otherwise applicable BFC under Schedule SGS-TOUE or SGS-TOU.

Option 2 establishes a demand charge limit for separately metered or submetered EV charging load within Schedules SGS-TOU and LGS-TOU, and uses the same submetering charge and BFC system as Option 1. I recommend that the demand charge limit be designed to produce a maximum implied volumetric rate that is approximately the same as a residential ratepayer would pay to charge an EV under a standard flat rate option such as Schedule RES. Alternatively, a cap based on a percentage of a ratepayer's bill attributable to demand charges could be used to similar effect.

I do not recommend Option (3), demand aggregation, or Option (4), a daily demand charge design, for immediate deployment because both involve greater complexities and consideration of additional issues. However, both of these options should have a place in continued discussions of EV-supportive rates and innovative rate designs more generally. Such a discussion could take place as part of the larger rate design study recommended by Public Staff Witness Floyd in DEC's pending rate case if the Commission adopts that recommendation.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. I recommend that the Commission direct DEP to file separate, targeted EV-specific tariffs for both residential and non-residential dedicated EV charging, reflecting the core characteristics discussed in my testimony. I believe this should occur within 60 days of the order in this rate case.

I also recommend that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements, including quarterly reports from DEP updating the Commission and parties on deployment status, tariff enrollment, ratepayer savings, system cost savings, and any other information that the Commission deems relevant to support evaluation of the tariffs and their future evolution. If the Commission orders the comprehensive rate design study recommended by Public Staff Witness Floyd in DEC's pending rate case, this investigatory docket could become part of or be used to support that effort.

Finally, I recommend that any rates established pursuant to a Commission decision remain available, at a minimum, until any successors or replacements are adopted pursuant to the system of Commission review that I recommend above.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that existing Schedule R-TOU be made available for submetered home EV charging with the modest submetering charge described above in place of the tariffed BFC. With the exception of not being available for submetered use, Schedule R-TOU already contains several characteristics that are supportive of home EV charging, as follows:

1. Three pricing periods and short duration on-peak periods;
2. A price differential between the off-peak rate and the otherwise applicable flat rate that should be sufficient to produce meaningful bill savings for EV charging, taking into account a modest incremental metering charge and a typical amount of home EV charging; and
3. An off-peak pricing period with a duration of at least eight hours that allows ample time for low voltage charging to produce a battery charge sufficient for a reasonable length trip or commute.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that a rate or rates for submetered and standalone EV charging be established for non-residential ratepayers under a design that features time variation and mitigates the outsized effects that demand charges have on charging costs. More specifically, the rate or rates should:

1. Address the issues presented by demand rates for non-residential EV charging installations by doing one or both of the following: (a) modifying Schedule SGS-TOUE to permit submetering for EV loads and eliminating or relaxing the maximum demand-based availability limitations currently contained in Schedule SGS-TOUE for EV load, or (b) applying a demand charge limit to Schedules SGS-TOU and LGS-TOU that caps demand charges at an implied maximum volumetric rate, or alternatively, a percentage of the ratepayer's monthly bill;
2. Use the otherwise applicable BFC for standalone charging stations and a submetering charge in place of the BFC for charging units located behind an existing meter; and
3. Remain available to participants for ten years from the date of their enrollment in order to provide a reasonable level of investment certainty to prospective equipment owners.

I also recommend that the Commission consider the demand aggregation and daily demand charge options discussed in my testimony as it pursues future refinements.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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-1

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments.* July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues.* July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri.* 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar.* 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends.* Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets.* 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar.* 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

North Carolina Utilities Commission. Docket No. E-7 Sub 1214. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

Virginia State Corporation Commission. Docket No. PUR-2019-00060. November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

Georgia Public Service Commission. Docket No. 42516. October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

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

In the Matter of:	)
Application of Duke Energy Progress,	)
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Charges Applicable to Electric Service	)
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DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-2

The State of Electric Vehicle Home Charging Rates

A SUMMARY

PRESENTED TO
Colorado PUC

PREPARED BY
Ahmad Faruqui
Ryan Hledik
John Higham

October 15, 2018

THE Brattle GROUP

Introduction and Methodology

Introduction

- The purpose of this presentation is to summarize residential EV-specific rate offerings in the United States
- The presentation includes the following sections:
  - Drivers and goals of EV-specific rates
  - A survey of current EV-specific rate offerings
  - Review of two pilot studies of EV-TOU effectiveness

Methodology

- The survey draws upon the following sources:
  - OpenEI Utility Rates Database
  - Utility tariff sheets

Drivers and Goals of EV-Specific Rates

Background

EV rate offerings are an opportunity improve the economic efficiency of EV charging behavior

- Consumer electric vehicles use approximately 225-275 kWh per month
- Level 1 charging consumes 1.4 kW of power
- Level 2 charging uses 6.2-7.6 kW of power
- A majority of EV charging occurs at home

Possible Utility Goals

1. Encourage EV adoption by reducing charging costs
2. Provide price signals that encourage optimal EV charging patterns while accurately collecting costs

The impact of rate design on EV attractiveness depends on (desired/actual) charging patterns

Annual EV Charging Cost per Traveler

Charging Profiles \ Rate Designs	Flat rate	TOU (3:1 ratio)	TOU (10:1 ratio)	Inclining block rate	Unconstrained demand charge	Peak period demand charge
Off Peak L1	$744	$510	$289	$971	$562	$550
On Peak L1	$744	$1,059	$1,356	$971	$639	$676
Post-Commute L2	$744	$886	$1,021	$971	$976	$1,155
Off Peak L2	$744	$510	$289	$971	$882	$550
On Peak L3	$744	$1,290	$1,807	$971	$1,335	$1,656
Autonomous Fleet	$744	$824	$899	$971	$808	$904

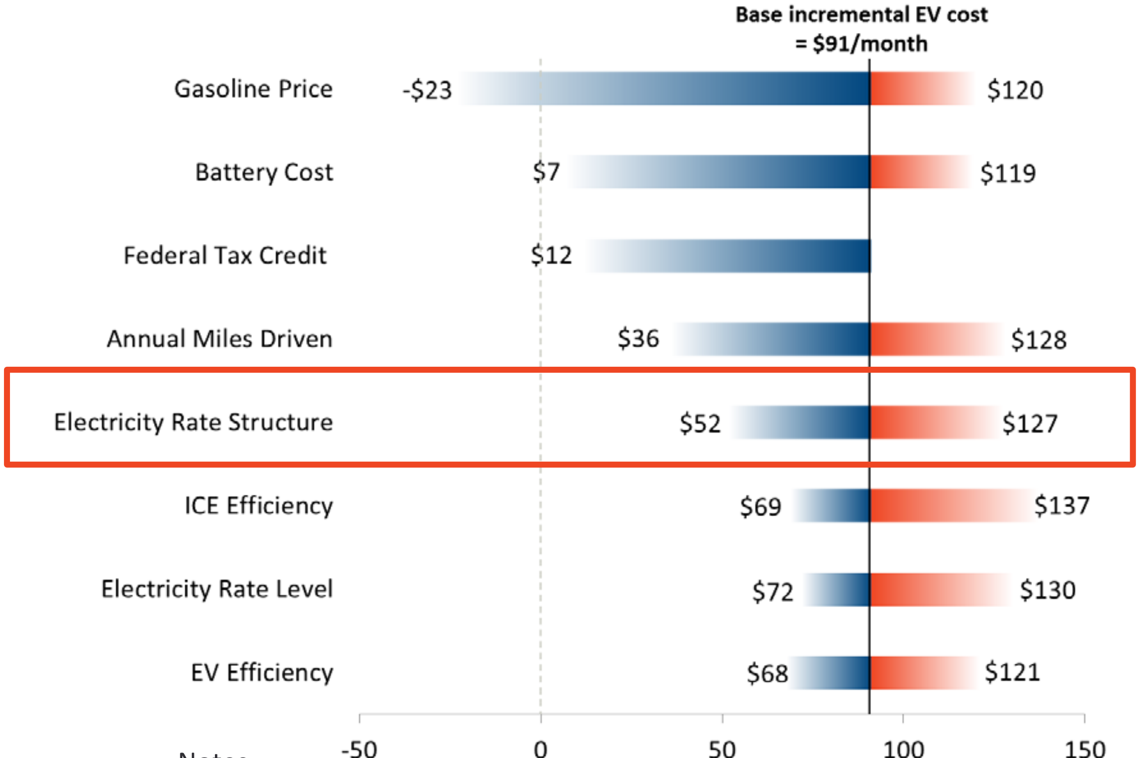
Comparable annual fuel cost of an ICE vehicle at $3/gal, 30 mpg is **$1,460**

Notes:
Rates and charging profiles are purely illustrative
Typical annual residential electricity bill is $1,140
Assumes constant vehicle miles traveled across all charging profiles
Each rate is applicable to whole home load, but figures shown are only incremental EV charging costs
Rates are revenue neutral for a class average residential customer

- TOU and demand charges incentivize off-peak charging but also introduce an element of financial risk for the EV owner
- It will be important to understand the extent to which customers are able and willing to respond to these price signals
- Technology that automates charging control will likely play a key role
- Fleets with higher utilization likely favor frequent, fast charging and potentially have less flexibility to respond to price signals

Rate design appears more likely to influence charging patterns than to impact EV adoption

Incremental Monthly Cost of EV Ownership Relative to ICE Vehicle (Illustrative)



Notes:
Results are illustrative.
The "Base incremental EV costs" is a levelized value over the life of the vehicle (10 years, 150,000 miles) reflecting the higher costs of the battery and lower fuel costs. Range shown is based on "high" and "low" assumptions for each key cost driver. See appendix for assumptions behind sensitivity analysis.

Comments

- Rate design appears to impact total EV ownership costs modestly relative to other cost drivers, though this is heavily dependent on charging patterns
- Additionally, there are significant non-economic drivers of vehicle adoption
- Thus, rate design may be a better tool for influencing the behavior of EV owners rather than being a primary consideration in the vehicle purchase decision

Utilities and Types of Rates

21 US utilities are currently offering EV-specific rates

- 12 Investor Owned Utilities
- 6 Municipal Utilities
- 3 Cooperatives

31 unique EV rate designs

- 27 TOU rates (1 of which has inclining blocks)
- 2 Inclining Block rates
- 1 Flat rate
- 1 Flat rate with flat demand charge

Differences in rate applicability

- 18 rates apply to entire residence
- 8 rates apply strictly to EV charging, metered separately (the costs of separate metering are generally incurred by the customer)
- 5 rates can be applied to entire residence or strictly EV charging

Rates – General Trends

- Diverse array of rate offerings
- Most utilities' EV-specific rates are more advantageous than comparable non-EV offerings. Designed to encourage enrollment and off-peak charging by offering:
  - Cheaper off-peak rates
  - Reduced or eliminated tiers of inclining block rate
- A few rates are less advantageous than comparable non-EV rates (longer or more expensive peak periods). These rates are generally required in order to receive utility-sponsored EV rebates or utility-financed charging infrastructure.
- Several pilot programs are testing ultra-high price ratios (>10)
- Several rates are either identical to other non-EV residential rates or are the only TOU rates offered.

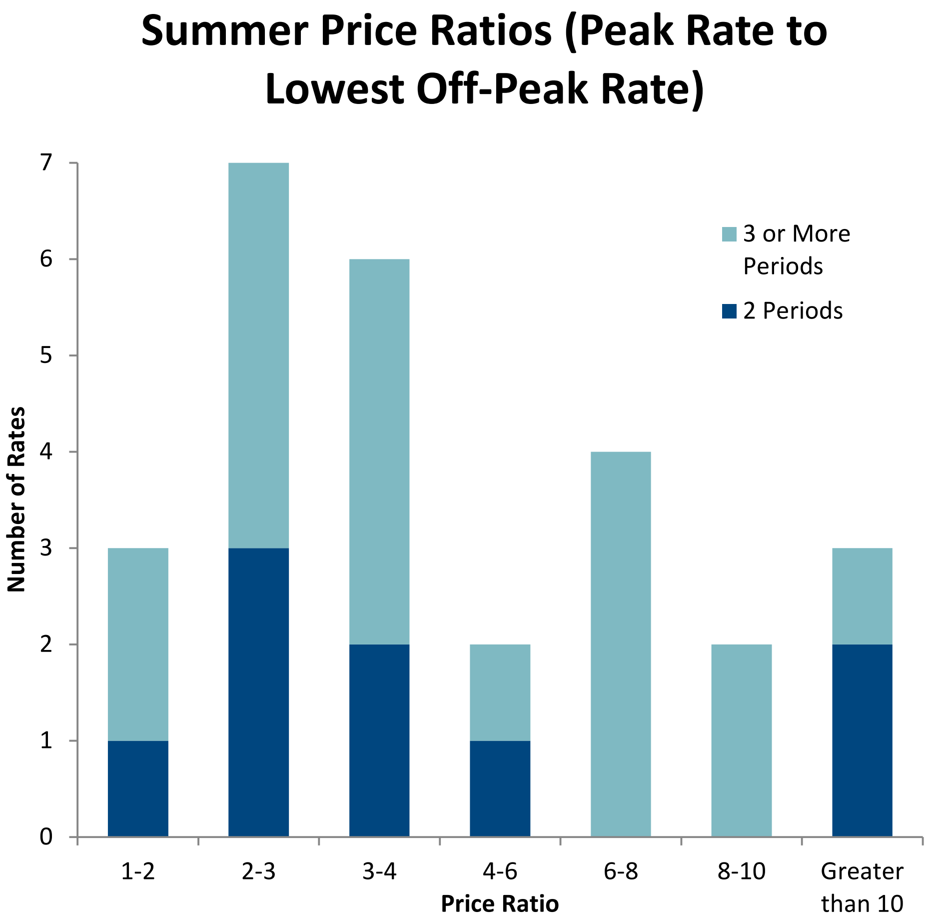
TOU Rates

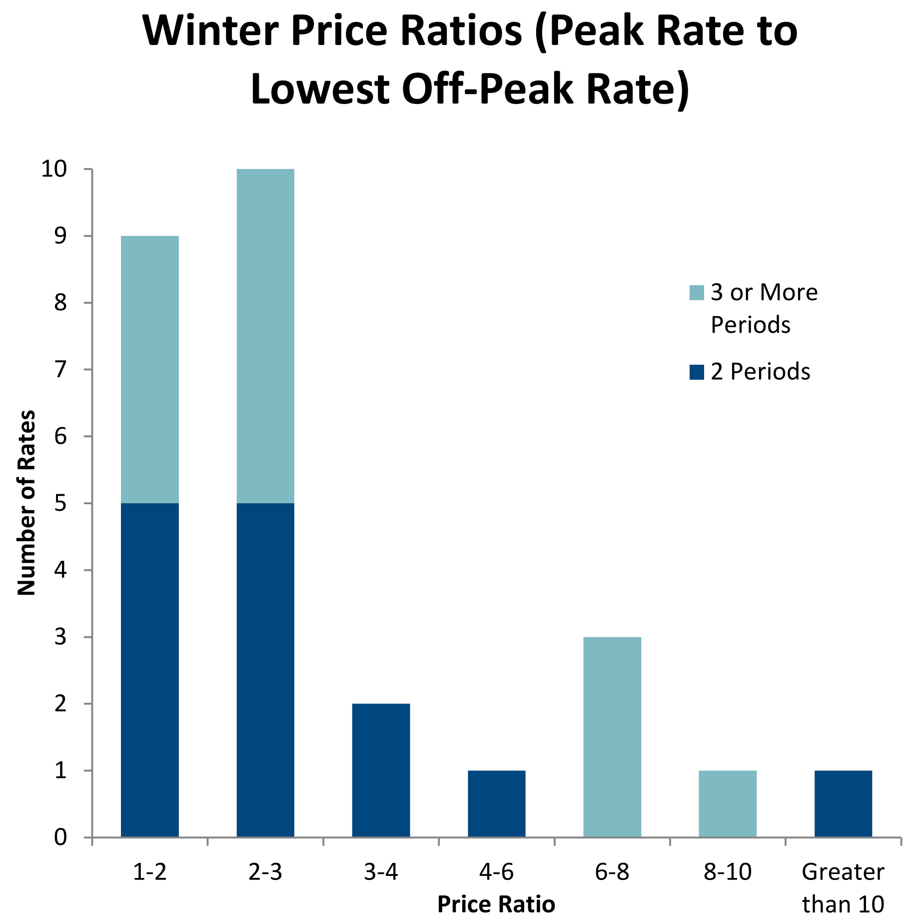
Of the 27 TOU rates:

- 9 have 2 pricing periods in both Summer and Winter
- 11 have 3 pricing periods in both Summer and Winter
- 5 have 3 pricing periods in Summer but 2 in Winter
- 2 have 4 pricing periods

Many different arrangements of pricing periods, seasons, price ratios, and fixed costs.

TOU Rates – Price Ratios



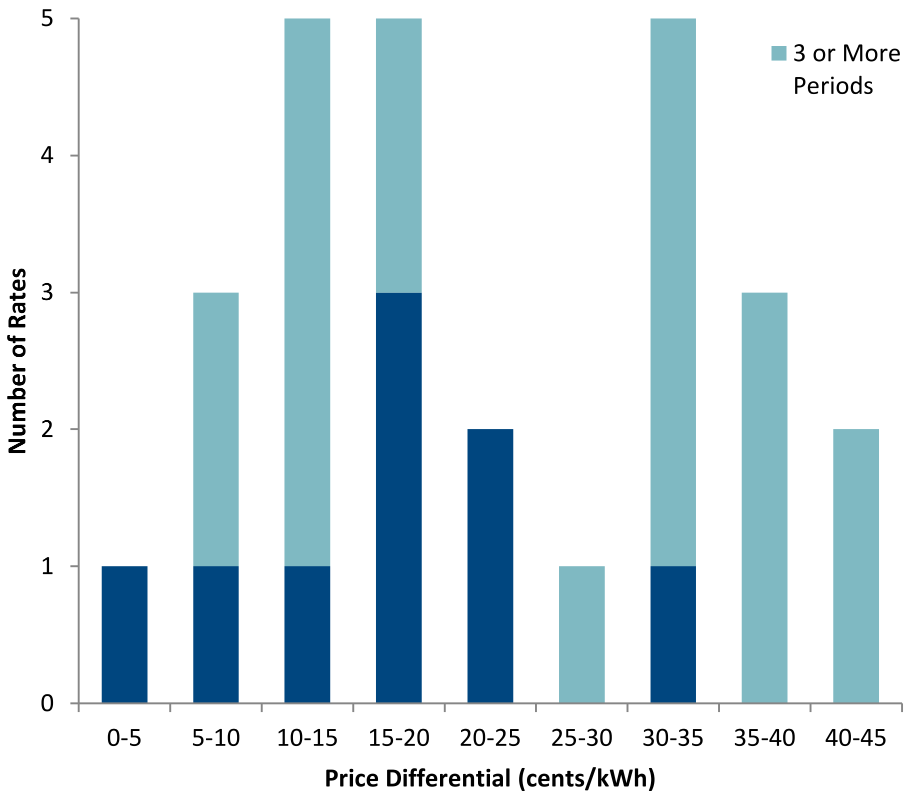


2 Period Median = 3.19
3 or More Period Median = 3.74

2 Period Median = 2.36
3 or More Period Median = 2.54

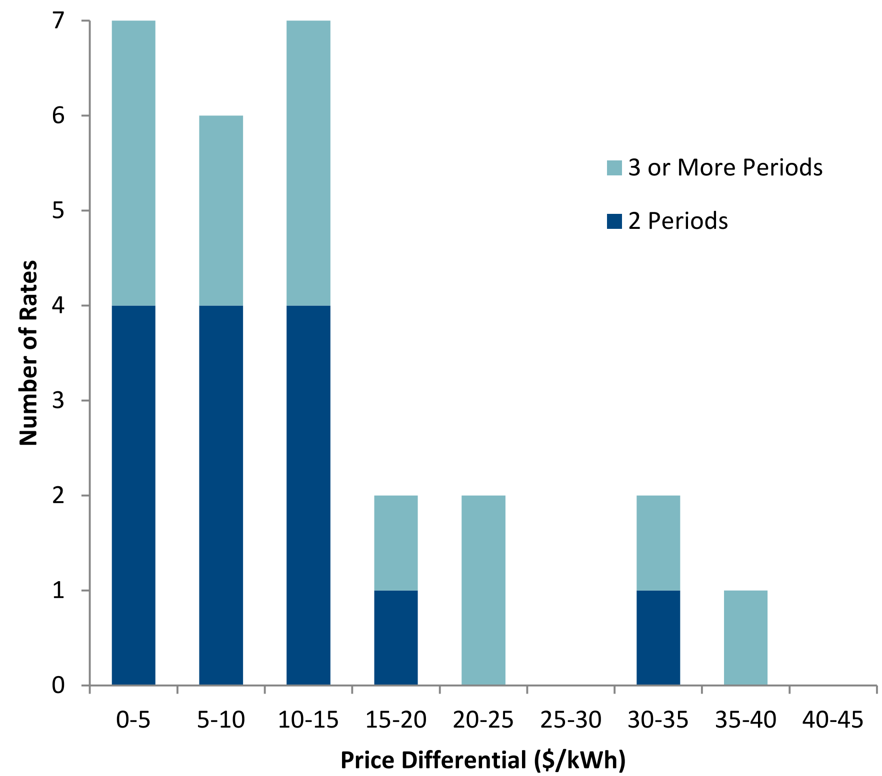
TOU Rates – Price Differentials

Summer Price Differentials (Peak Rate to Lowest Off-Peak Rate)



2 Period Median = 17 cents/kWh
3 or More Period Median = 28 cents/kWh

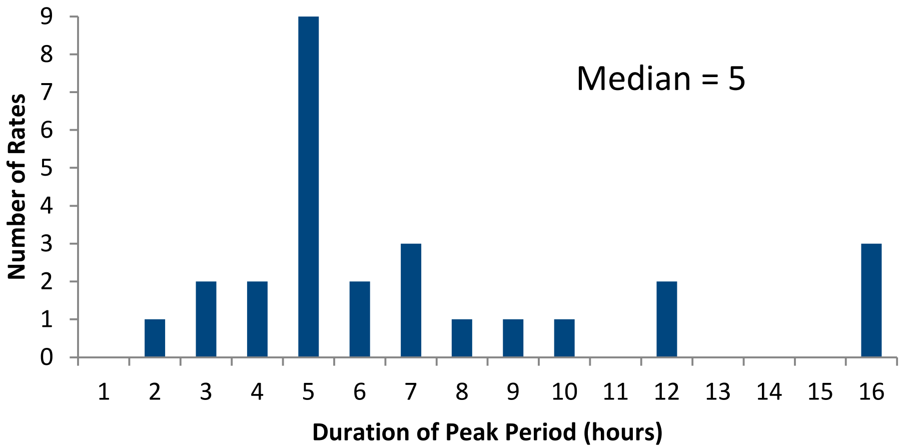
Winter Price Differentials (Peak Rate to Lowest Off-Peak Rate)



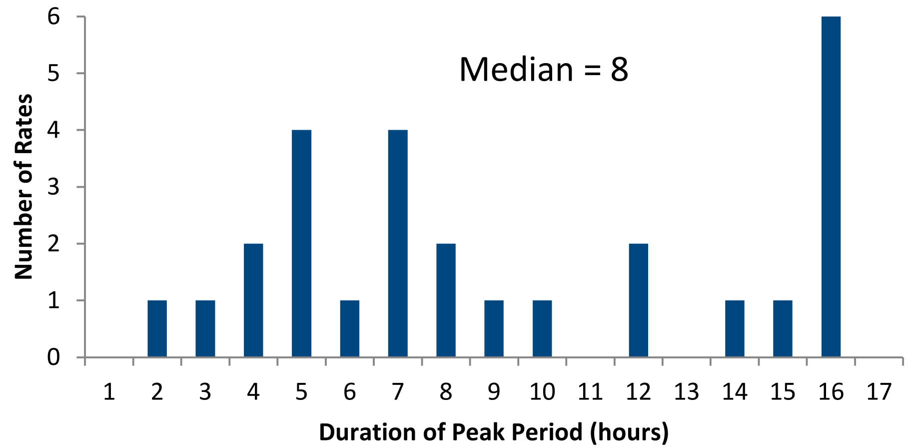
2 Period Median = 9 cents/kWh
3 or More Period Median = 12 cents/kWh

TOU Rates – Duration of Peak Window

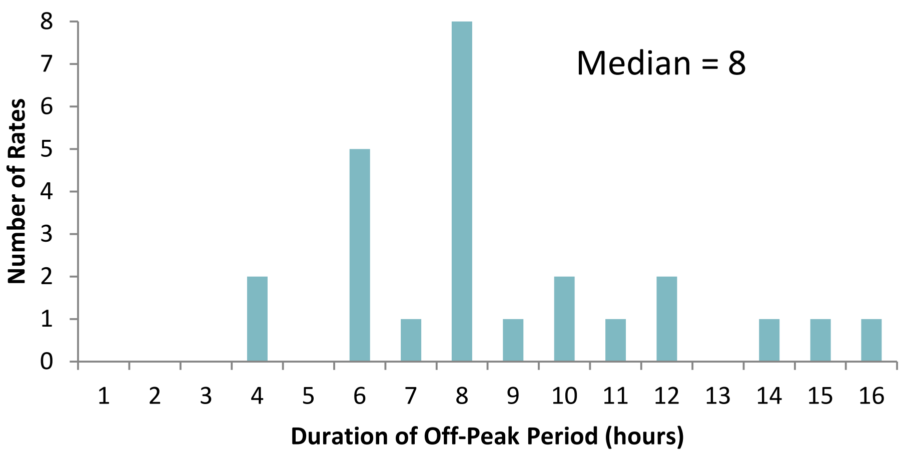
Summer Peak Period Duration



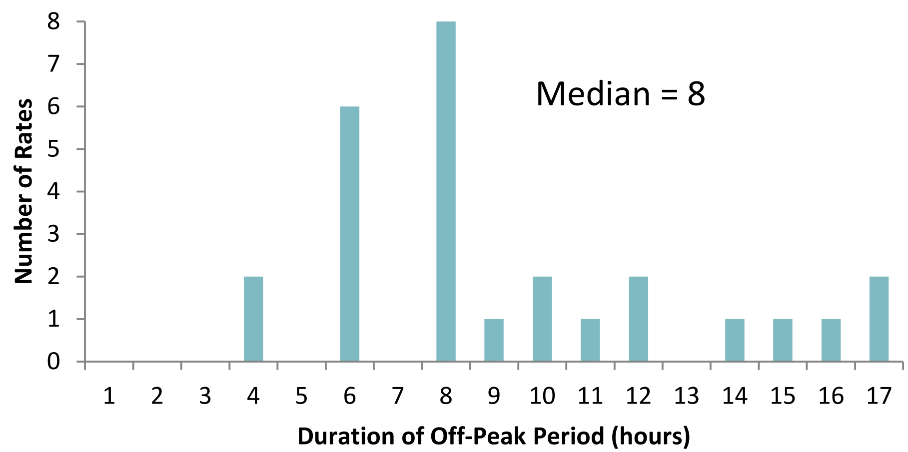
Winter Peak Period Duration



Summer Off-Peak Period Duration



Winter Off-Peak Period Duration



Pilot Studies

San Diego Gas & Electric – EV TOU Pilot Study

- 3 different 3-period rates with varying price ratios (roughly 2, 4, and 6 for peak/super off-peak)
- All rates applied strictly to EV charging, not the entire residence
- 430 participants owning a Nissan LEAF with a charging timer and Level 2 charging
- EV owners were found to be responsive to price signals and shifted a majority of charging to super off-peak hours
- Participants exhibited learning behavior, increasingly shifting consumption as the study progressed

EPRI – Salt River Project EV Driving, Charging and Load Shape Study

- Observational study of 70 EVs of various models subject to different rate plans
- TOU rates found to be highly effective in shifting peak loads
- Energy use and charging load varied widely across different models and charger types

Conclusions

- Electric vehicle owners have significantly different needs, load shapes, and flexibility than other residential customers, supporting the creation of new rate offerings
- EV TOU rates encourage optimal charging patterns, creating a win-win for utilities and EV owners
- Initial findings from two EV charging pilots indicates that charging load is highly responsive to rate design, though further empirical research is needed in this area

References

- Electric Power Research Institute. “Electric Vehicle Driving, Charging, and Load Shape Analysis: A Deep Dive Into Where, When, and How Much Salt River Project (SRP) Electric Vehicle Customers Charge.” 3002013754. July 2018.
- Cook, Jonathan, Candice Churchwell, and Stephen George. “Final Evaluation for San Diego Gas & Electric’s Plug-in Electric Vehicle TOU – Pricing and Technology Study.” Nexant, Inc. Submitted to San Diego Gas & Electric. February 20, 2014.

Appendix: Monthly Cost of EV Ownership Assumptions

General Assumptions:

- 10 year vehicle life
- 24 kWh battery
- 10% registration fee
- 12% charging losses
- $600 charger cost
- 7% annual discount rate

Sensitivity Assumptions:

Component	Units	Low	Base	High
Electricity Rate Level	*cents/kWh*	8	**12**	20
Electricity Rate Structure		Off-Peak w/ TOU (10:1)	**Flat**	Post-Commute w/ Demand Charge
EV Efficiency	*miles/kWh*	5.0	**3.0**	2.0
ICE Efficiency	*MPG*	25	**30**	50
Annual Miles Driven	*miles/year*	30,000	**15,000**	5,000
Federal Tax Credit	*$*	7,500	**0**	---
Battery Cost	*$/kWh*	200	**500**	600
Gasoline Price	*$/gal*	$5.00	**$3.00**	$2.00

PRESENTED BY

Ahmad Faruqui

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Ahmad Faruqui's consulting practice is focused on the efficient use of energy. His areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents. These include electric and gas utilities, state and federal commissions, independent system operators, government agencies, trade associations, research institutes, and manufacturing companies. Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand and the United Kingdom and given seminars on all 6 continents. His research been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He holds BA and MA degrees from the University of Karachi, an MA in agricultural economics and Ph. D. in economics from The University of California at Davis.

Brattle Projects & Research on Electrification

Ongoing

- Forecasting the impacts of new utility initiatives on EV adoption (EPRI)
- System Dynamics based modeling of EV adoption and impacts on utilities (ComEd)
- Developing a framework for evaluating the cost-effectiveness of ratepayer-funded electrification programs (EPRI)
- Reviewing rate design alternatives for public EV fast charging stations (EEI)
- Developing forward-looking ratemaking strategies, including rate design for EVs (GRE)

Recent

- Assessment of the benefits and costs of residential grid-interactive electric water heating (NRECA/NRDC)
- Assessment of the economy-wide technical potential for electrification (Brattle White Paper)
- Exploration of the implications of ride sharing and vehicle automation for electric utilities (Brattle White Paper, Electricity Journal Article, PUF Article)

Additional Brattle Resources

The Electrified Future is Shared, Jürgen Weiss, Public Utilities Fortnightly, PUF 2.0, Mid-February 2018

The electrification accelerator: Understanding the implications of autonomous vehicles for electric utilities, Jürgen Weiss, Ryan Hledik, Roger Lueken, Tony Lee, Will Gorman, The Electricity Journal 30 (2017) 50–57, December 2017

New Sources of Utility Growth: Electrification Opportunities and Challenges; Retail Energy Practice Briefing Series; The Brattle Group, November 2017

Electrification: Emerging Opportunities for Utility Growth, Jürgen Weiss, Ryan Hledik, Michael Hagerty and Will Gorman, January 2017

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Our Electrification Services

- Market Potential Assessments
- Integrated Modeling to Understand Interdependencies
- Multi-criteria Screening of Electrification Options
- Electrification Strategy Development
- Macroeconomic Impact Modeling
- Rate Design for Electric Vehicle (EV) Charging
- EV Adoption Modeling
- Regulatory Strategy and Support
- Pilot Development

About Brattle

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world. We aim for the highest level of client service and quality in our industry.

OUR SERVICES

Research and Consulting

Litigation Support

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OUR PEOPLE

Renowned Experts

Global Teams

Intellectual Rigor

OUR INSIGHTS

Thoughtful Analysis

Exceptional Quality

Clear Communication

Our Practices and Industries

ENERGY & UTILITIES

- Competition & Market Manipulation
- Distributed Energy Resources
- Electric Transmission
- Electricity Market Modeling & Resource Planning
- Electrification & Growth Opportunities
- Energy Litigation
- Energy Storage
- Environmental Policy, Planning and Compliance
- Finance and Ratemaking
- Gas/Electric Coordination
- Market Design
- Natural Gas & Petroleum
- Nuclear
- Renewable & Alternative Energy

LITIGATION

- Accounting
- Analysis of Market Manipulation
- Antitrust/Competition
- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Labor & Employment
- Mergers & Acquisitions Litigation
- Product Liability
- Securities & Finance
- Tax Controversy & Transfer Pricing
- Valuation
- White Collar Investigations & Litigation

INDUSTRIES

- Electric Power
- Financial Institutions
- Infrastructure
- Natural Gas & Petroleum
- Pharmaceuticals & Medical Devices
- Telecommunications, Internet, and Media
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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-3

Smart Electric Power Alliance

Residential Electric Vehicle Rates That Work

ATTRIBUTES THAT INCREASE ENROLLMENT

November 2019

In Partnership with:

THE Brattle GROUP

E4THE FUTURE

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About E4TheFuture

E4TheFuture is a nonprofit organization advancing clean, efficient energy solutions. Advocating for smart policy with an emphasis on residential solutions is central to E4TheFuture's strategy. "E4" means: promoting clean, efficient Energy; growing a low-carbon Economy; ensuring low income residents can access clean, efficient, affordable energy (Equity); restoring a healthy Environment for people, prosperity and the planet. Dedicated to bringing clean, efficient energy home for every American, E4TheFuture's endowment and primary leadership come from Conservation Services Group whose operating programs were acquired in 2015 by CLEAResult. Visit www.e4thefuture.org.

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Enel X is Enel's global business line dedicated to developing innovative products and digital solutions. Enel X's e-Mobility division is the leading provider of grid-connected electric vehicle charging stations with over 50,000 smart stations across the world. The company's JuiceNet® platform provides smart grid management of EV charging, which is used by thousands of drivers, global automakers, commercial businesses and utilities. In North America, Enel X has ~3,400 business customers, spanning more than 10,400 sites, representing approximately 4.6 GW of demand response capacity and 20+ battery storage projects. For more information please visit www.enelx.com.

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The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world. We help energy and utility market participants worldwide anticipate and navigate the challenges and opportunities in changing markets and regulatory environments. Brattle's experts are at the forefront of the latest developments and trends facing the energy industry, and our experience spans the full spectrum of complex, high-stakes matters relating to resource planning and approvals, regulatory policy assessments, rate design, contract litigation, market conduct, performance and enforcement, financial analysis, and mergers & acquisitions. For more information, please visit www.brattle.com.

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Executive Summary

Electric vehicle (EV) market forecasts predict strong growth in adoption, with much of the associated charging load occurring at home. Utilities can influence home charging behaviors through EV time-varying rates that incentivize residential customers to charge off-peak thereby minimizing distribution system impacts and avoiding the need for costly infrastructure upgrades and investments. This report analyzes residential EV time-varying rates based on survey results from customers and utilities and identifies factors that increase rate enrollment. For the purposes of this report, we included **residential time-varying rates that were identified and marketed as rates specifically available to EV drivers**.

To collect insights on residential EV time-varying rates implemented to date, SEPA worked with The Brattle Group to develop and administer a survey for U.S. utilities that had a qualified rate in-place for at least one year. In addition, to collect insights from EV drivers on time-varying rates, SEPA co-developed a survey with Enel X which was distributed nationwide to the company's JuiceNet-enabled charging station customers.

Why Residential EV Time-Varying Rates Are Important

EVs can use between 3.3 to 20 kilowatts (kW) of electricity, which can exceed the total peak demand of a home in some regions. The increase in peak load can also strain the local distribution system, particularly when several EVs are clustered on single transformers. Residential EV charging load is well-suited to respond to price signals. Most light-duty EVs are parked the majority of the day[1] and can be easily programmed through the car and/or the charger to begin charging at a pre-set time. In the future, it will be desirable to have this and more advanced control capabilities across the grid in a more dynamic framework, in order to respond to real-time market and operating conditions.

As illustrated by our utility and customer survey results, time-varying rates are an effective tool for utilities to influence EV customer charging behavior by incentivizing home charging during off-peak periods. While some industry representatives have questioned the need for EV-specific rates—rates designed for and marketed to EV drivers—to capture benefits, we found that customers on an EV time-varying rate were generally 1) more familiar with the rate rules and 2) more likely to charge off-peak compared to their generic time-varying rate counterparts. EV-specific rates also allow utilities to offer rate options that appeal to a wider range of customer types and preferences across their service territories than they could with only a generic time-varying rate. In the near-term, EV-specific time-varying rates—a form of passive managed charging—offer utilities an effective mechanism to shift residential EV charging behavior to off-peak time periods. The following sections highlight key findings from our research.

Factors that Increase Enrollment

According to the research, certain EV time-varying rate attributes lead to higher customer uptake. Utilities that have a marketing budget for these rates see a 3x increase in enrollment. Further, those using more than three marketing channels have a 1.4x increase in customer enrollment (Figure 1). Utility-driven EV time-varying rate initiatives, as opposed to those required or recommended by customers, governance boards, or legislatures, also have a corresponding 2.4x increase in enrollment. Other important factors include free enrollment and realized bill savings for average EV customers.

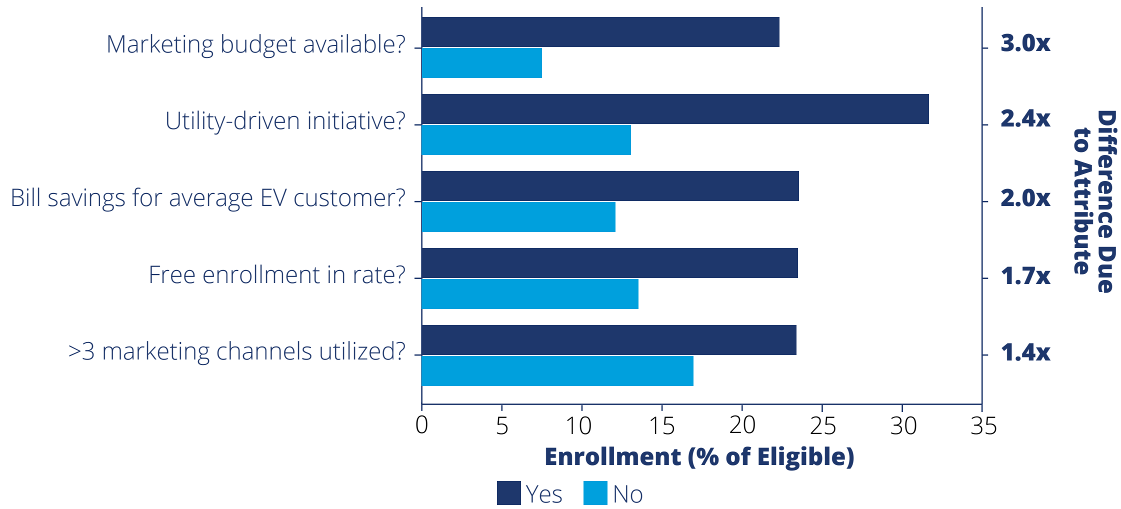
Rate Design and Marketing Are Important

Rate design considerations for time-varying rates, such as bill neutrality, peak/off-peak pricing windows, and peak-to-off peak pricing ratios are also important. An effective rate design conveys price signals that are transparent and actionable, giving customers the necessary information and a strong incentive to shift their charging load from the utility's system peak hours to designated off-peak periods. These factors also directly affect the value proposition for customer enrollment in a time-varying rate. As outlined in this report, the opportunity to reduce their bill is a top motivation for customers. The utility survey results in this report demonstrate that the time-varying rates offered by utilities have successfully shifted charging to off-peak periods, lowering utility bills for the average EV customer.

Further, providing meaningful rate choices, such as offering larger discounts, varied off-peak hours and other significant variations, to customers is more likely to induce higher enrollment and increase off-peak charging behavior. This is reflected in the utility survey results and in the San

1 See Donald Shoup, 2011, The High Cost of Free Parking, which asserts cars are parked up to 95% of the time.

Figure 1: Average Enrollment by EV Time-Varying Rate Attribute



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20

Diego Gas & Electric case study summarized in the report. Rate design considerations can include combinations of whole-home and EV-only rates, metering configurations, and off-peak hour definitions that better serve individual customer and grid-wide needs. Dynamic rates, retroactive bill credits via load disaggregation, or subscription rates can also provide more choices and appeal to a broader base of customers compared to straight time-of-use rates, which represent the majority of rates implemented to date.

Marketing directly affects enrollment and need not be expensive. According to the survey, 70% of customers learned about their time-varying rate through low-cost marketing efforts, such as rate information on the utility website. Of survey respondents that didn't enroll in an available rate, it was largely due to their lack of awareness of the rate and the related potential for savings. While customer awareness of EV rates is high, utilities can take measures to improve education and customer understanding of the rates.

Metering Considerations

Metering techniques are important for rate implementation and can determine the difference between a successful program and a program failure. Meter option considerations include the cost of enrollment and equipment, the type of administration, the ease of integration with existing billing systems, the security and reliability of charging signals, and the ability of the program to handle EV technology evolution.

Today, utilities employ at least five metering approaches to implement EV time-varying rates: 1) existing meter, 2) submeter, 3) secondary meter, 4) telemetry in the EV charger, or 5) load disaggregation via data pulled from a meter or other device, such as a meter collar. While the survey didn't identify a correlation between enrollment and a specific metering approach, it is clear from the data that customers want options that minimize enrollment costs. The report provides case studies of innovative rate programs and metering approaches from Indiana Michigan Power (a subsidiary of American Electric Power), San Diego Gas & Electric, Austin Energy, Xcel Energy Minnesota, and Braintree Electric Light Department.

A Bridge to Direct Load Management

As the utility industry builds the capabilities for direct EV charging load control, utilities may be able to leverage the on-board EV batteries for advanced grid benefits. Time-varying rates are an effective first step in developing a strong relationship with EV customers. Creating a positive customer experience with load management is important. Eventually, direct load control can complement time-varying rates and provide more dynamic grid services than can rates alone. Direct load control can also help minimize the challenges posed by the formation of new 'timer peaks' on the distribution system (e.g., if customers begin charging simultaneously when the off-peak window begins, creating a new spike in load).

Beyond EVs, residential demand response and price-responsive controlled usage can also be provided by other equipment, such water heaters, air conditioners, swimming pool pumps, and laundry equipment. As customers become more comfortable with controlled loads through managed EV charging programs, it may also lead to greater acceptance of other utility load-control programs.

Based on our findings, utilities should engage EV customers early to avoid losing customer engagement "momentum." Understanding customer motivation is valuable, and while customers are primarily motivated by savings, a large percentage of customers in our survey are also interested in helping the environment. Describing how load management can lead to increased use of renewable energy and other environmental goals can help utilities increase enrollment and participation in EV time-varying rate programs.

Residential EV time-varying rates can serve as a bridge between passive and active managed charging options by showing customers how, in exchange for providing grid benefits by controlling their charging, they can save money. Utilities should also consider incorporating direct load control with a time-varying rate program. The timing for doing so will depend on EV penetration and the cost-benefit of load management options. Although the need for direct load control may not be immediate, utilities should ensure that equipment installed today is compatible with future pricing and system reliability frameworks by testing options today.

Report Contents

This report provides a comprehensive overview of residential EV time-varying rates and draws conclusions about next steps for residential EV rate design and programs based on the results of a utility survey and a customer survey. The appendices provide a complete list of EV time-varying rates offered by utilities as of September 2019, a list of suggested reading materials, and definitions of time-varying rates. This report was made possible by funding from E4TheFuture and Enel X.

Table 1: Report Roadmap

The Case for Time-Varying Rates	Defines time-varying rate options and describes the benefits and limitations of these rates.
Residential EV Time-Varying Rates Landscape	Describes why utilities are pursuing these rates, how utilities are marketing them, and why customers are interested in residential EV rates.
Consumer Insights	Provides the customer survey results from nearly 3,000 EV drivers who have either 1) enrolled in a time-of-use (TOU) program or 2) had a utility TOU rate option available, but chose not to enroll.
Features of Effective EV Time-Varying Rates	Highlights the utility survey results to identify the features of rates and programs that contribute to the highest customer enrollment.
What To Do About Metering	Highlights utility metering approaches, the pros and cons of each, and outlines case studies of utilities that have developed innovative rate programs through various metering approaches.
Conclusion	Recommendations for utilities as they consider options for EV time-varying rates and describes other research topics to explore, as the industry continues to investigate load management strategies.
Appendices	▪ Appendix A includes a complete list of EV time-varying rates ▪ Appendix B includes suggested reading materials ▪ Appendix C includes expanded definitions of time-varying rates and illustrations

Source: Smart Electric Power Alliance, 2019.

1) Introduction

Electric vehicles (EVs), in certain regions of the U. S., are quickly becoming one of the largest flexible loads on the grid. Depending on vehicle type, a single EV represents from 1.4 kW to 20 kW of instantaneous load[2], or 500 to 4,350 kWh/year of energy consumption.[3] This is similar to the impact of introducing air conditioning systems and electric water heaters decades ago. As of July 2019, customers have purchased over 1.28 million EVs in the United States,[4] consuming an estimated 4.97 terawatt-hours (TWh) per year.[5]

EV adoption is expected to increase as vehicle prices decline and new models become available. Navigant forecasts that EVs in the U.S. will reach over 20 million in 2030 with an energy consumption of 93 TWh.[6] According to forecasting models by the National Renewable Energy Laboratory (NREL), electrified transportation may result in between 58 to 336 TWh of electricity consumption annually by 2030, depending on the speed and type of vehicle deployment.[7] This represents the equivalent average annual energy consumption of 5.6 million to 32.3 million U.S. homes.[8]

Forecasts predict that much of the future charging load will occur at home, as it does today. Utilities can strongly influence residential charging behavior by incentivizing their customers to charge off-peak to minimize distribution system impacts and avoid the need for costly infrastructure upgrades and investments. As described in the 2019 SEPA report, *A Comprehensive Guide to Electric Vehicle Managed Charging*, this is known as managed charging.

There are two forms of managed charging: passive and active.[9] Passive managed charging uses behavioral load control strategies, including rates and incentives, to influence customers. Active managed charging is direct load control enabled through the charger, the vehicle, or some other interface that can remotely control a charging event to respond to real-time grid conditions.[10]

This report presents empirical evidence regarding the effectiveness and benefits of passive managed charging via time-varying rates for residential EV customers. In the near-term, passive managed charging offers utilities an effective strategy for shifting residential EV charging behavior to off-peak time periods that can effectively lead to more sophisticated active managed charging programs, as discussed in Chapter 2.

In order to collect insights on residential EV time-varying rates implemented to date, SEPA collaborated with The Brattle Group ("Brattle") to develop and administer a survey ("utility survey") for all U.S. utilities that had a qualified rate for at least one year. Further, to collect insights from EV drivers on time-varying rates, SEPA co-developed a survey with Enel X (formerly known as eMotorWerks) which was distributed nationwide to the company's JuiceNet-enabled charging station customers ("customer survey"). Additional survey information is provided in the research methodology.

2 Using Level 1 to Level 2 charging stations; Direct Current Fast Charging (DCFC) load would be higher.

3 SEPA, 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging*.

4 Electric Drive Transportation Association, July 2019, https://electricdrive.org/index.php?ht=d/sp/i/20952/pid/20952

5 Assumes 3,858 kWh per EV per year based on data from the U.S. Department of Energy Alternative Fuels Data Center. Assumes all vehicles sold since 2010 are still operating in the U.S.

6 Navigant forecast provided in April 2019 to SEPA staff. See also: EEI/IEI, November 2018, *EV Sales Forecast and the Charging Infrastructure Required through 2030.*

7 National Renewable Energy Laboratory, 2018, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, https://www.nrel.gov/docs/fy18osti/71500.pdf.

8 Based on 2017 U.S. Energy Information Administration data that residential U.S. electricity consumers used an average of 10,400 kWh per year. See https://www.eia.gov/tools/faqs/faq.php?id=97&t=3.

9 Note: other terms used for managed charging include smart charging, V1G, intelligent charging, direct load control, or passive load control.

10 Additional information about active managed charging can be found in SEPA's 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging* report.

Research Methodology

SEPA collected primary research data from electric utilities that have developed time-varying rates for EV customers. The majority of the rates currently offered by the sampled utilities are time-of-use (TOU) rates. SEPA contacted 50 utilities, of which 28 responded to the survey with a total of 40 EV specific time-varying rates. Of the 28 utilities, 19 were investor-owned, 4 were municipally owned, 4 were member-owned cooperatives and one was a community choice aggregator.

The SEPA survey team employed best practices to maximize response rates, and performed data verification and validation with survey respondents while collaborating with Brattle to analyze the results.

Brattle's analysis focused on identifying factors that contribute to a "successful" EV TOU rate. For the purposes of this analysis, "success" is defined as a high enrollment rate or significant shifting of load to desirable (i.e., lower-priced off-peak) periods. The load shifting data indicates that the TOU rates shifted the majority of charging to off-peak hours. Estimates of rate enrollment were significantly more varied. Brattle's analysis limited consideration of the survey responses to those that would be useful for analyzing drivers of high enrollment. They eliminated survey responses that appeared to be duplicates, where rates had expired, and where enrollment estimates were not provided. Survey responses were reviewed and assigned to specific categories relevant to the quantitative analysis (e.g., assigning a "yes" or "no" flag based on whether or not a utility indicated that budget was available to market the rate). Average enrollment was calculated for each specific category (e.g., average enrollment among those utilities that had a marketing budget versus those that did not). The averages were calculated as a simple average across utilities, rather than weighting by number of customers which would skew the results to the findings of larger-sized utilities. A statistical technique known as "lasso analysis" was then applied to empirically estimate the relative importance of each factor in driving higher enrollment in the TOU rates.[11] Brattle shared their insights with SEPA for the purposes of developing the report.

Concurrent with the utility survey, Enel X and SEPA developed and distributed a customer survey which generated 2,967 US-based responses from JuiceNet users. This provided data on EV customer familiarity with their rate structure and behavioral energy insights. JuiceNet respondents represented a wider customer sample beyond the utilities included in the SEPA/Brattle survey. Many of Enel X's customers reside in California, where close to half of the nation's EVs are located and where residential TOU rates will be the default rate within investor-owned utility service territories. Nearly 50% of respondents to Enel X's survey (1,422 out of 2,967 respondents) live in California. Further, since the survey only sampled the customers of one EV charging manufacturer, the pool of respondents may reflect customers that were specifically interested in the JuiceNet smart charging features.

2) The Case for Time-Varying Rates

As EV adoption grows, significant load will be added to the grid. If customers charge their EVs during peak demand hours, this increase in demand could create unwelcome effects. One way to minimize peak load impacts is through the use of time-varying rates. This section defines time-varying rate options and describes the benefits and limitations of these rates.

A. What Are Time-Varying Rates?

For much of the day, less than half of the electric grid's capacity is being used. This is because the grid is designed to handle peak demand.[12] As a result, reducing the peak—during which the generation and delivery of electricity is more costly—is advantageous for both the utility and customer, as it minimizes the system costs and therefore

11 Least Absolute Shrinkage and Selection Operator (LASSO) is a technique used to improve the prediction accuracy of regression models by identifying a subset of covariates (i.e., model variables) that generally have the most predictive value.

12 Girouard, Coley., 2015, *Time Varying Rates: An Idea Whose Time Has Come?*, https://blog.aee.net/time-varying-rates-an-idea-whose-time-has-come.

the electricity rate ultimately charged to customers. By pricing electricity higher at times when demand is at its peak, customers are incentivized to shift their use to off-peak times, minimizing their electricity use when it matters most to the grid. Rates with prices that vary throughout different hours of the day or days of the week are known as time-varying rates.

The benefits of time-varying rates to utilities and customers are not limited to aligning rates more closely with the underlying costs associated with generating and delivering electricity. Time-varying rates are also an effective tool for motivating customers to shift their energy usage to off-peak or other desirable time periods to help achieve certain grid outcomes, such as renewable energy integration. For example, time-varying rates can help utilities maintain grid stabilization by signaling lower prices to customers for hours during which there is a significant amount of uncurtailable renewable generation.

While a form of time-varying rates—TOU rates—have been offered by utilities for decades, the recent increase in consumer adoption of distributed energy resources has spurred a new wave of rate offerings, including those specifically designed for EV customers.

Definition of EV Time-Varying Rates

For the purposes of this report, we included residential time-varying rates that were identified and marketed as rates specifically available to EV drivers. Often, these rates have specific off-peak or super off-peak windows designed to accommodate the charging duration needs of EVs and to incentivize charging during designated off-peak periods. The rates are sometimes—though not always—limited to EV drivers. Some of these rates apply to the customer's entire home energy usage, while other rates are specific to the customer's EV charging load. There are instances where an EV TOU rate looks similar in design to a generic TOU rate and is marketed as an EV rate. The authors used the rate title and descriptions developed by the utilities to identify the residential EV rates listed in Appendix A and the utility survey outreach contact list.

A typical on-board EV charger consumes about 3.3 to 9 kilowatts (kW) of demand, which can exceed the total peak demand of a home, depending on the region. Level 2 charging loads for vehicles with larger battery packs can be up to 20 kW.[13] A concern utilities face, as the penetration of EVs continues to increase, is the potential for the clustering of EVs in certain sections of the distribution system. If an EV cluster develops on a particular feeder, it could become overloaded and result in the need for costly repairs and upgrades by the utility. Time-varying rates offer utilities a potential solution by incentivizing customers to shift their EV charging load from peak to off-peak time periods, during which feeders have more available capacity and are less likely to become overloaded.

Residential EV charging load is well-suited to respond to price signals.[14] Most light-duty EVs are parked the majority of the day and overnight[15] and can be easily programmed through the car and/or the charger to begin charging at a pre-set time. Time-varying rates are an effective tool to incentivize customers to shift their charging to off-peak periods, as confirmed by our utility and customer survey findings.

In this report, time-varying rates are placed in one of seven categories: Time-of-Use, Subscription Rates, Off-Peak Credits, Real Time Pricing (RTP), Variable Peak Pricing (VPP), Critical Peak Pricing (CPP), and Critical Peak Rebates (CPR):[16]

- **Time-of-Use Rates** typically have two or more price intervals (e.g., peak, off-peak, super-off-peak) that differ based on levels of demand observed throughout the day. Sometimes, these prices vary by season, but both the prices and the designated price interval hours for each tier remain constant.
- **Subscription Rates** allow customers to pay a fixed monthly fee for electricity and other utility-provided services in exchange for unlimited consumption during specified hours of the day or days of the week.
- **Off-Peak Credits** can take the form of a fixed or variable incentive provided as a rebate or a bill credit in exchange for restricting consumption to designated hours of the day or days of the week.
- **Real Time Pricing (RTP)** are variable, hourly prices determined either by day-ahead market prices or real-time spot market prices.

13 SEPA, 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging*, see Table 1.

14 Multi-Unit Dwelling (MUD) customers may face different considerations than typical residential customers when responding to time-varying price signals. For example, tenants residing in MUDs may share common EV chargers and would likely not have equal access to the chargers during lower-priced off-peak time periods. This could result in potential access and equity issues based on the schedules of each tenant.

15 See Donald Shoup, 2011, *The High Cost of Free Parking*, which asserts cars are parked up to 95% of the time.

16 Definitions adapted from: Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf. Subscription Rates and Off-Peak Credits are not discussed in the EDF primer.

- **Variable Peak Pricing (VPP)** is a hybrid of TOU and RTP, with price intervals (e.g., peak, off-peak) that are constant like a TOU rate but allow for the price charged during the peak tier to differ day to day.
- **Critical Peak Pricing (CPP)** has a higher rate at designated peak demand events (also called "critical events") on a limited number of days during the year to reflect the higher system costs during these hours.
- **Critical Peak Rebate (CPR)**, also called Peak Time Rebate (PTR), is the inverse of CPP. Utilities pay customers a rebate for each kWh of electricity they reduce during peak hours of peak demand events.

The latter four rate structures are known as "dynamic pricing" because the price signals are not static and more closely reflect the real-time market conditions. Some of these rate options can be combined on a single rate schedule. For example, a number of utilities offer customers a rate schedule which pairs a TOU rate with a CPP component.

Further details about time-varying rate options and illustrations are provided in Appendix C.

B. Benefits of Time-Varying Rates

Time-varying rates are successful in altering customers' charging habits. Benefits of shifting charging habits via rates, as defined by the Environmental Defense Fund[17] and others include:

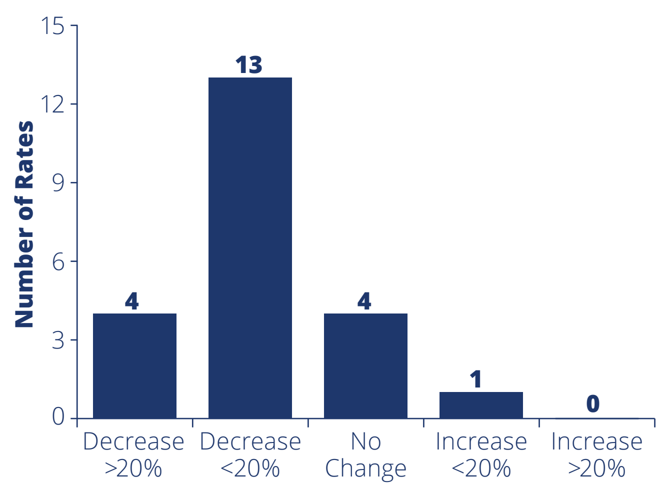
- Reducing energy supply costs by making greater use of lower-cost resources and limiting the use of the highest-cost energy;
- Reducing pollution by shifting demand to times when clean energy sources are generating electricity;
- Providing economic benefits to all utility customers through the grid efficiencies captured using off-peak charging;
- Avoiding or deferring capacity investments in generation, transmission, and distribution;
- Reducing the cost of infrastructure upgrades/replacement/repairs, particularly transformers;
- Responding to customer needs, incentivizing customer EV adoption, and influencing beneficial customer charging behavior; and
- Encouraging sustainable behavior changes, resulting in more reliable, predictable, and pronounced peak load reductions for utilities.

While some industry representatives have questioned the need for EV-specific rates to capture these benefits, our customer survey found those on an EV TOU rate were 1) more likely to charge off-peak a greater percentage of the time compared to their generic TOU rate counterparts and 2) more familiar with the rate rules (see "Customer Insights" chapter).

With the proper rate structure, utilities can use EV specific rates to provide load management, generate cost savings for EV owners, encourage more off-peak charging, and increase customer satisfaction (as indicated by enrollment length). These benefits are verified by responses to the utility survey, including:

- Utilities reported, on average, more than 90% of customers responded to the off-peak price signal.[18]
- The majority of utility respondents saw their average EV customer's charging bill decline (see Figure 2).
- Approximately 40% of utilities surveyed reported persistent changes in charging behavior after the introduction of EV time varying rates.[19]

Figure 2: Change in Customer EV Bill After Enrolling in EV Rate



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=30
Note: Six respondents indicated that the bill change was 'unknown'.

17 Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf

18 Results from utility survey respondents. N=15

19 Results from utility survey respondents. N=29

- Utilities also saw a high level of retention on their EV rate, with over 95% of participants who were enrolled at the beginning of the year remaining enrolled at the end of the year.[20]

A 2014 San Diego Gas & Electric EV pricing pilot[21] found that EV owners were highly responsive to modest price signals and even more so to higher price ratios. Customers exposed to a price ratio of 1-to-1.2-to-2 (super-off-peak to off-peak to peak hours) shifted 73% of their charging to the super-off-peak period, while customers exposed to a price ratio of 1-to-2.4-to-3.8 (super-off-peak to off-peak to peak hours) shifted 84% of their charging to the super-off-peak period. The degree of load shifting increased consistently over the study horizon as customers became more familiar with the time-varying rate. This evidence of customer price-responsiveness is consistent with the customer survey results as discussed in the "Customer Insights" chapter of this report.

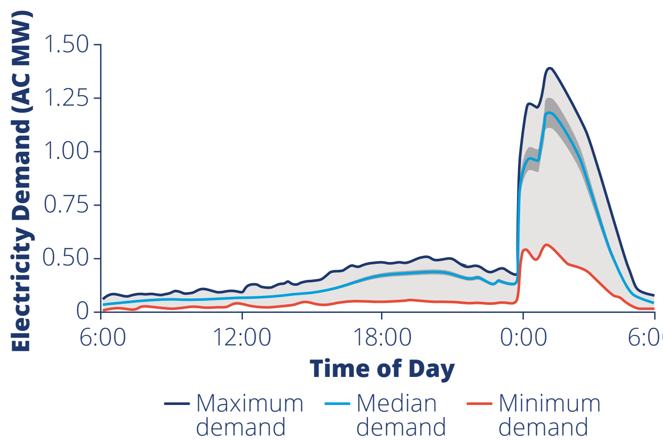
C. Considerations for Time-Varying Rates

While time-varying rates can provide a range of system benefits, they can also present operational challenges, particularly when applied to EV charging. Some concerns exist regarding the potential for households to program their EVs to begin charging exactly at the same off-peak time, leading to a new load "spike" (also known as a "timer peak") during these off-peak hours as illustrated in Figure 3. At the local distribution level, the result could be a new peak that would contribute to capacity constraints, the effect of which could be exacerbated by geographically clustered EVs. This issue was discussed at length in the SEPA report, *A Comprehensive Guide for Electric Vehicle Managed Charging*.[22]

Similarly, FleetCarma found in a 2019 study that static residential TOU rate structures reduce variability but can cause unintentional coincident load.[23] Innovative rate design practices, such multiple pricing intervals that gradually increase the price from the off-peak period over several hours, could help to address this concern. It is, however, an issue that could warrant more active management of charging load as EV adoption increases.

Active managed charging, which enables the utility or another third party to shift charging loads to reduce potential distribution system impacts and better align charging with lowest-cost electricity and renewable generation (e.g., during wind or solar peaks) could provide additional benefits. Beyond EVs, residential demand response and price-responsive controlled usage can also be provided by other equipment, such water heaters, air conditioners, swimming pool pumps, and laundry equipment. Gaining customer comfort with controlled loads, such as enrollment in an EV managed charging program, may contribute to greater acceptance of other programs.

Figure 3: Illustration of San Diego Gas and Electric Weekday "Timer Peak"



Source: MJ Bradley & Associates, 2017[24]
Note: This is a rendition of the original graphic.

As part of a comprehensive EV strategy, utilities should identify the stage gates at which they can introduce active managed charging in addition to passive managed charging programs, such as a time-varying rate. The timing of an active managed charging program will depend on several variables, including the penetration of EVs in a utility service territory (especially among those that can shift loads) and the cost-benefit of load management options. While the exact parameters of this transition are not yet fully defined, from a qualitative perspective, it may resemble Table 2. As an example, utilities in states

20 Results from utility survey respondents. N=16

21 Nexant, February 2014, *Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU Pricing and Technology Study*. https://www.sdge.com/sites/default/files/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf

22 Smart Electric Power Alliance, May 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging*, www.sepapower.org.

23 FleetCarma, 2019, *EV Profile & Manage EV Charging Load For Demand Response*, https://www.fleetcarma.com/docs/ProfileandManage2019-FleetCarma-web.pdf&sa=D&ust=1565040346133000&usg=AFQjCNGcJrPwvJjBb1wDd4vihfFWAh_m8w

24 MJ Bradley & Associates, April 2017, *Electric Vehicle Cost-Benefit Analysis*, https://mjbradley.com/sites/default/files/CO_PEV_CB_Analysis_FINAL_13apr17.pdf

like Hawaii and California facing rapid growth in EVs, high amounts of distributed solar, and higher electricity costs may achieve greater grid benefits through an active managed charging solution than through a traditional TOU rate.

Residential EV time-varying rates could serve as a bridge between passive and active managed charging options. As customers begin their EV journey, building a high level of trust between the customer and the utility is essential to the success of active managed charging. Customers don't buy EVs to provide grid support; however, if they had a positive load management experience using time-varying rates, they may be more likely to consider an active managed charging program.

American Electric Power (AEP) and its subsidiaries, are planning to leverage their existing utility smart meter networks to enable EV-only TOU rate offerings and implement an active load management program as highlighted in the case study in Chapter 6.

Table 2: Potential Residential EV Load Management Options Based on Utility System Conditions

EV Load Management Option	Penetration of Light-duty Residential EVs	Available Distribution Capacity (including substations/ transformers/ feeders)	Integration of Intermittent Loads (e.g., solar, wind)	Cost of On-Peak Electricity
Passive				
Behavioral Load Control (e.g., text message during system peak)	Low	High	Low	Average
Generic Time-of-Use Rate	Low	High	Medium	Above average
Generic Dynamic Pricing Rate	Low	High	High	High
EV Time-of-Use Rate	Medium	Medium	Medium	Above average
EV Dynamic Pricing Rate	High	Medium	High	High
Active				
Managed Charging (designed to minimize distribution impacts)	High	Low	High	Above average
Managed Charging (designed to minimize on-peak electricity costs)	High	Medium	High	High
Vehicle-to-Grid	High	Low	High	High

Source: Smart Electric Power Alliance, 2019.

3) Residential EV Time-Varying Rates Landscape

Utilities are introducing residential EV time-varying rates with a variety of design features, configurations, and marketing strategies. This section identifies the current rates landscape, why utilities are pursuing them, how utilities are marketing them, and the levels of customer interest in residential EV rates.

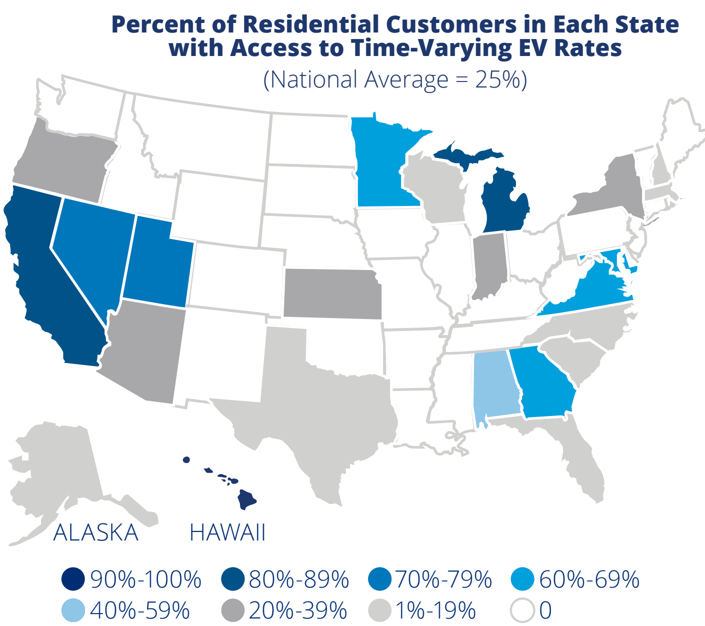
A. Current Status

With the expanded adoption of residential advanced metering infrastructure (AMI), many utilities so-equipped are offering at least one residential time-varying rate. As of 2017, approximately 9% of U.S. utilities and energy suppliers offered a residential time-varying rate with over 6.5 million customers enrolled.[25]

As of September 2019, SEPA and Brattle identified 64 active residential EV rates being offered by 50 utilities.

The landscape of residential EV time-varying rate offerings is changing quickly with the majority of these rates introduced in the past few years. Figure 4 illustrates where these residential EV time-varying rates are located and the share of residential customers with access. It also highlights observations about these rates. Table 3 provides specific insights into the EV time-varying rates provided by the utility survey respondents.

Figure 4: Characteristics of Active Residential EV Time-Varying Rates



28 investor-owned utilities, **12** municipal utilities, and **10** electric cooperatives	**18** pilot programs, **46** fully implemented residential rates

Of the 64 EV rates, **58** were TOU rates, **1** was a subscription rate with an on-peak adder, and **5** were off-peak credit programs.

How the rate applies to the home load:

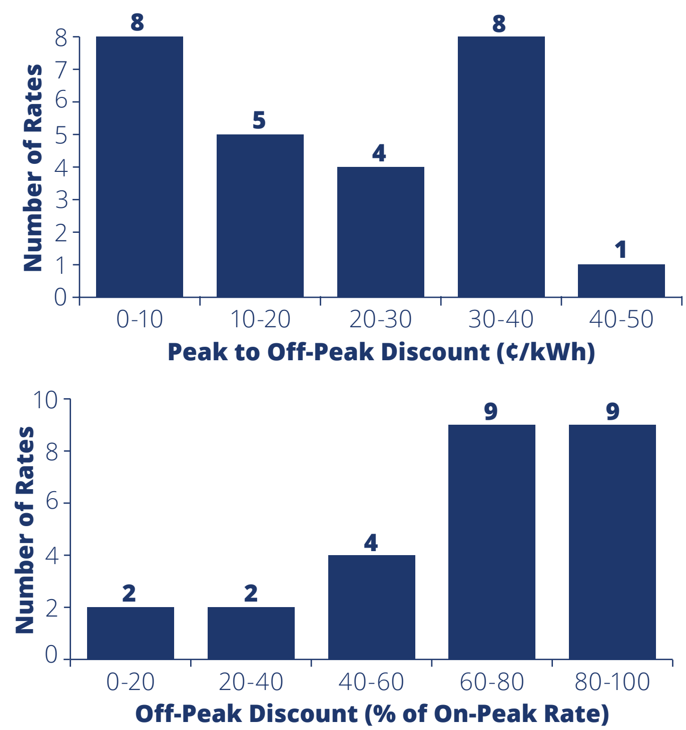
- **35** rates apply to the **total household energy consumption**, including the EV charging load.
- **21** rates **apply strictly to EV charging**. These rates typically require the installation of a second meter or submeter, and two rates are metered from a submeter in the EV charger itself.
- **8** rates allowed customers to **choose between whole home or EV-only options**.

Source: Smart Electric Power Alliance & The Brattle Group, 2019.

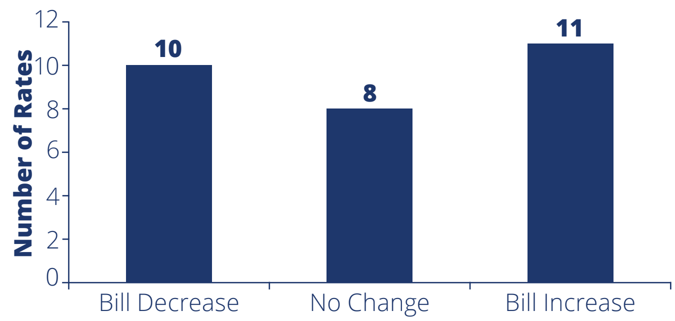
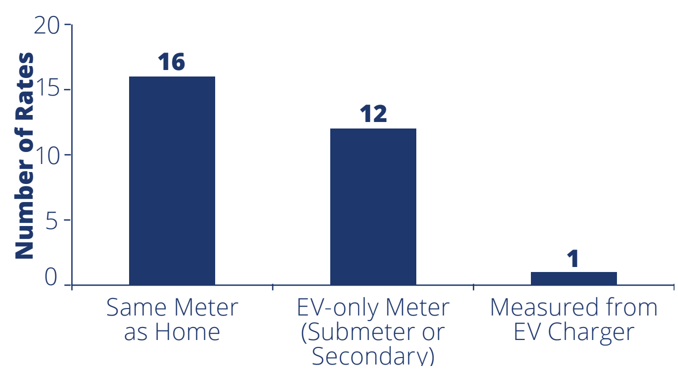
25 U.S. Energy Information Administration, Form EIA-861, 2017. https://www.eia.gov/electricity/data/eia861/. A total of 310 EIA electric power industry survey participants had residential time-varying rates with customers enrolled, in a population of 3,421 utilities and nontraditional entities such as energy service providers. Includes 290 entities with residential TOU rates, 14 with real time pricing, eight with variable peak pricing, 25 with critical peak pricing, and 12 with critical peak rebates. Note that Form EIA-861 does not include Subscription Rates and Off-Peak Credits as forms of time-varying rates.

Table 3: Insights from Utility Survey Respondents with EV Time-Varying Rates	
Utility Motivations for Offering Rate	Utilities designed the rates to: ▪ **Encourage charging during low or negatively-priced wholesale power hours**, such as when renewable generation is being curtailed. ▪ **Discourage charging during specific times** when the distribution system is constrained. ▪ **Encourage EV adoption by lowering the overall total cost of ownership**.
Rate Design Features	The TOU rate offerings in the survey differ significantly across design features such as: ▪ The **peak-to-off-peak price ratio**. Several pilot programs have begun testing rates with significant differentials between the peak and off-peak period, such as peak-to-off-peak price ratios in excess of 10-to-1. ▪ **Number of pricing periods.** ▪ The **timing** of those periods. ▪ **Seasonality.**
Peak-to-Off-Peak Price Ratios	The price ratios of the rates varied from 1.2-to-1 to 15.5-to-1, with a **median of 3.6-to-1**. Similar variation is observed in the absolute price differentials, which range from $0.02 per kWh to $0.44 per kWh, with a **median of $0.20 per kWh**. Figure 5 illustrates the peak to off-peak discount in cents per kWh as identified by the utility survey.

Figure 5: Peak to Off-Peak Discount by Cents/kWh and Percent of On-Peak Rate



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=26.

Table 3: Insights from Utility Survey Respondents with EV Time-Varying Rates (Continued)	
Bill Neutrality Is Not a Standard Feature	Approximately one-third of the time-varying EV rates analyzed in the utility survey would provide an average participant with bill savings compared to the default rate, even in the absence of changes in charging behavior. For the other two-thirds, the customer's bill would remain the same or increase if charging load was not shifted to the off-peak period. Rates offering bill neutrality or savings encourage enrollment, however, as Figure 6 shows, this is not a standard feature. **Figure 6: Expected Bill Impact for EV Customer if Enrolled in EV Rate Without Change to Charging Pattern**  Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29.
Upfront Customer Costs	Despite potential savings, **some customers are deterred by the initial enrollment fees** for the installation of additional metering equipment (e.g., second meter, submeter, meter collar, EVSE). Some utilities socialize those expenses as part of a broader EV program so the customer enrollment fee is less of an issue for participants.
Cost Savings	Most of the rates are **more advantageous for flexible loads such as EVs** (including customers willing to shift EV charging to off-peak periods) **than the otherwise applicable residential rate**, offering significant savings opportunities through cheaper off-peak rates and reduced or eliminated rate tier(s).
Rate Enrollment rRequirements	In some cases, rate enrollment was required for customers to receive **utility-sponsored EV rebates or utility-financed charging infrastructure**.
Metering Configurations	Metering configurations varied widely with a majority being applied to the whole home (Figure 7). **Figure 7: EV Rate Metering Configuration for Utility Survey Respondents**  Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29.

Source: Smart Electric Power Alliance, 2019

Innovative Rate Example: Free Energy! Cobb EMC NiteFlex Rate

Cobb Electric Membership Corporation in Georgia created a unique rate to incentivize EV owners to shift their charging to off-peak hours. Using the NiteFlex rate, customers can recharge their EV during super off-peak for free for the first 400 kWh per month.[26] The rate is split into three tiers with peak, off-peak, and super off-peak times:

- The **peak** rate ($0.1350/kWh) is between 1pm - 9pm.
- The **off-peak** rate ($0.07181/kWh) is between 9pm - Midnight and 6am - 1pm.
- The **super off-peak** rate is between Midnight - 6am where the initial 400 kWh are free, and any additional usage is at a rate of $0.045/kWh.

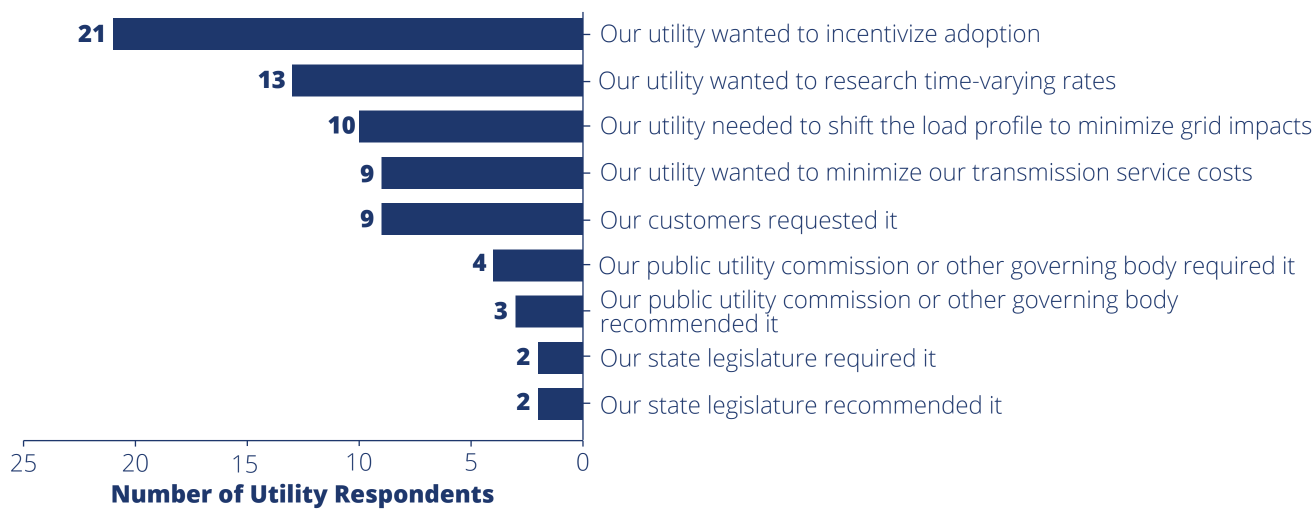
In addition to EVs, this rate also applies to other smart appliances or energy loads that can be shifted to later hours.

B. Why Are Utilities Pursuing EV Time-Varying Rates?

In response to the increased customer adoption of light-duty residential EVs, utilities have been developing and offering their customers EV time-varying rates. As Figure 8 shows, the four most commonly cited reasons were to incentivize (in the context of encouraging and promoting) EV adoption, research time-varying rates, shift the load profile, or minimize transmission costs. Less than half the utilities offering residential EV time-varying rates did so because their customers requested it or because the utility governance board or legislative body required or recommended it. Additional insights about utility motivations and lessons learned are included in the chapter, "Features of Effective EV Time-Varying Rates."

Respondents indicated that customers with Level 2 chargers and battery electric vehicles (BEVs) were more likely to enroll in an EV time-varying rate. Though the reasons weren't captured in the utility survey, higher enrollment for customers with Level 2 chargers and BEVs could be due to the amount of energy required to charge larger batteries leading to potentially higher bill savings. Knowing that enrolled customers are highly motivated by saving money, these larger savings may drive BEV customers to enroll. This may indicate that as more customers purchase BEVs over plug-in hybrid electric vehicles (PHEVs), the pool of potential EV rate customers will grow.

Figure 8: Reasons Utilities Created EV Time-Varying Rate



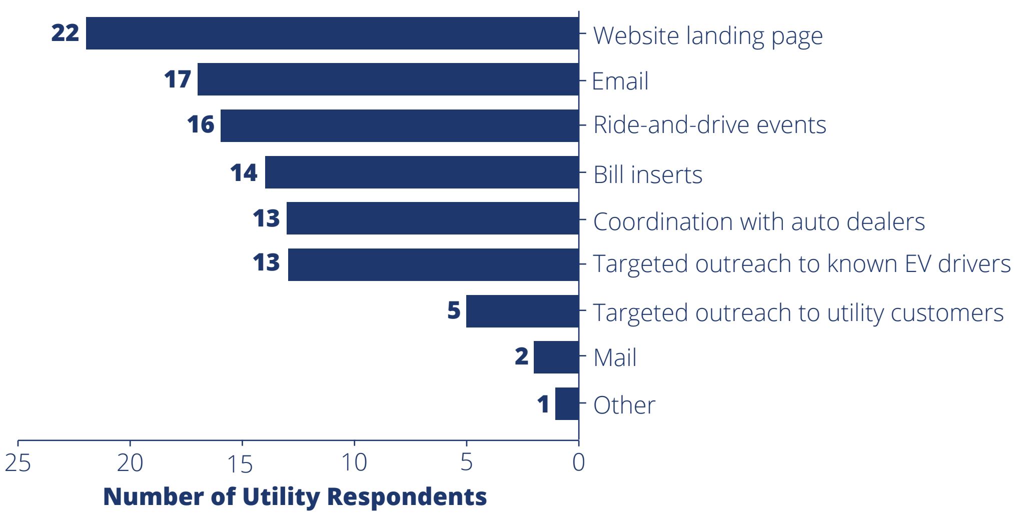
Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29. Respondents selected all that applied.

26 Cobb EMC, 2019, NiteFlex Rate, https://www.cobbemc.com/content/niteflex.

C. How are Utilities Marketing EV Time-Varying Rates?

A wide range of methods are used to market the EV rates. Utilities typically used more than one method, favoring the easiest and lowest-cost solutions such as a website landing page and emails (Figure 9). Ride-and-drive events are also popular among utilities; however, as discussed in the "Consumer Insights" chapter, ride-and-drive events may be less successful at recruitment.[27] Bill inserts, coordination with auto dealers, and targeted outreach to known EV drivers are also common strategies.

Figure 9: Utility EV Rate Outreach Methods



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29. Respondents selected all that applied.

D. Consumer Interest in EV Rates

A recent report, *Rate Design: What Do Consumers Want and Need?*[28], by the Smart Energy Consumer Collaborative (SECC), a nonprofit that has been researching consumers' energy-related needs and wants since 2011, identified interest in EV rates from residential customers. SECC surveyed consumers from two types of rate states:

- **Alternative rate states**[29] offer rates beyond flat rates including TOU, interruptible load, VPP, CPP, RTP, net energy metering, low-income subsidies, and green power plans. These states include California, Wisconsin, Oklahoma, Delaware and the District of Columbia.
- **Traditional rate states** offer flat rates, flat progressive (include pricing tiers that increase in price with volume) rates, and flat regressive (including pricing tiers that decrease in price with volume) rates. These include all remaining states divided between the Northeast, Midwest, South and West.

When customers were asked to rate their interest on a scale of 0-10, with 0 meaning "not at all" and 10 meaning "very interested", respondents gave an average of 6.2 across all states (Table 4).

Interest did not vary significantly from state to state; however, different segments of the population had widely varying levels of interest (Table 5). Green Innovators and Tech-savvy Proteges both indicated an above average level of interest.[30]

27 A possible reason for this difference in data could be that utilities with higher enrollment were more proactive in outreach, and ride-and-drive events were a part of that outreach. The apparent success of ride-and-drive events from the utility's perspective could merely be a sign of the utility's overall more effective methods of outreach.

28 The full versions of SECC's research reports are available exclusively to members of the organization. Learn more about membership at smartenergycc.org.

29 Alternative rate states were defined by SECC and described in the report research methodology.

30 See also: *SECC, Consumer Pulse and Market Segmentation—Wave 7*, 2019. https://smartenergycc.org/consumer-pulse-and-market-segmentation-wave-7-report/.

Table 4: Residential Interest in EV Rate Plans, by State Type			
State Type	**States Include**	**Customer Interest**	**# Responses**
Alternative Rate State	California, Wisconsin, Oklahoma, Delaware and the District of Columbia	6.2 out of 10	N=546
Traditional Rate State	All remaining states that are not alternative rate states	6.0 out of 10	N=592
All States	All states	6.2 out of 10	N=1,138

Source: Smart Energy Consumer Collaborative, 2019.[31]

Table 5: Residential Interest In EV Rate Plans, by Segment			
Segment	**Characteristics**	**Customer Interest**	**# Responses**
Green Innovators	Lead the way in energy conservation. They are primarily middle aged (40%, 35–54) and evenly split gender-wise. They are more likely to have a post-secondary education. The combination of high education and being established in their career corresponds with another segment characteristic — they have the highest incomes. In fact, one-in-five households has a six-figure income.	7.1 out of 10	N=278
Tech- Savvy Proteges	Consumers who have the skill set and interest to save energy but need a push to take action. This segment is more likely to be male and younger. One-third are aged 18–34. Half have a post-secondary education and live with three or more people. Despite having the highest employment rate (67%), they are more likely to be middle-income earners. While they have the highest homeownership rate, they are also the most transient — half have moved cities in the past five years.	6.5 out of 10	N=392
Movable Middle	Straddles most metrics and are neither tuned-out nor highly engaged. Demographically, the Moveable Middle skews older and they're more likely to be retired. They have lower incomes and are less educated than the Green Innovators and Potential Proteges we have discussed. These consumers like to stay put—70 percent have not moved in the past five years, and over half live in an older home.	5.8 out of 10	N=262
Energy Indifferent	The oldest group of consumers overall. One-third are retirees aged 65+ and most have no post-secondary education. They are cost conscious. Many live in energy inefficient older homes, but because they have fewer appliances, their energy bills are relatively low.	4.7 out of 10	N=206

Source: Smart Energy Consumer Collaborative, 2019.[32]

31 SECC, 2019, *Rate Design: What Do Consumers Want and Need?*

32 Ibid.

This SECC research also shows a high level of interest in EV rates among certain segments of the population, which aligns with the customer types most interested and knowledgeable about EVs produced from additional SECC research in 2016 (Table 6). We would anticipate interest in EV rates to increase as more consumers become aware of the technology. However, in the near-term, customer segmentation should be considered as part of any outreach and marketing strategy.

Table 6: Level of EV Interest Defined by Consumer Segment

Segments	Perspectives	Key Demographics	Awareness and Interest in Solar/EV
Green Champions	"Smart energy technologies fit our environmentally aware, high-tech lifestyle."	Youngest, more likely to be college-educated	Relatively highest levels of solar and EV, nearly four times the interest level of Status Quo.
Savings Seekers	"How can smart energy programs help us save money?"	Younger, more likely to be college-educated	Lower level of awareness and interest in all types of solar and EV.
Status Quo	"We're okay; you can leave us alone."	More likely middle age, lower income renters, living in non-single family dwellings, less likely to be educated	Relatively lowest level of awareness and interest in all types of solar and EV.
Technology Cautious	"We want to use energy wisely, but we don't see how technologies can help."	Most likely homeowners who are older in age, less likely to be college-educated	Marginally higher than Savings Seekers on awareness and moderate interest in solar and EV.
Movers & Shakers	"Impress us with smart energy technology and maybe we will start to like the utility more."	More likely middle age, higher income, singe-family homeowners, college-educated	High levels of awareness comparable to Green Champions on average, but moderate interest levels in solar and EV.

Source: Smart Energy Consumer Collaborative, 2016.[33]

4) Consumer Insights

To identify what customers want from time-varying EV rates[34] and why they may have not participated in available utility rate options, the project team developed a customer survey that was sent nationwide to existing Enel X JuiceNet charger customers. This survey gathered nearly 3,000 responses.[35] The vast majority of those sampled said their utility offered a TOU rate (Figure 10). A very low number of EV drivers (10%) were not aware if the utility offered a TOU rate, signifying that the sample was knowledgeable about their utility rate options.

Many of Enel X's customers reside in California, where close to half of the nation's EVs are located and where residential TOU rates are becoming the default rate for residential customers in the Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric service territories.[36] Nearly 50% of respondents to Enel X's survey (1,422 out of 2,967 respondents) live in California. This report isolates the California population from the rest of the survey sample to minimize any survey bias. Not surprisingly, 90% of the California survey population reported having an

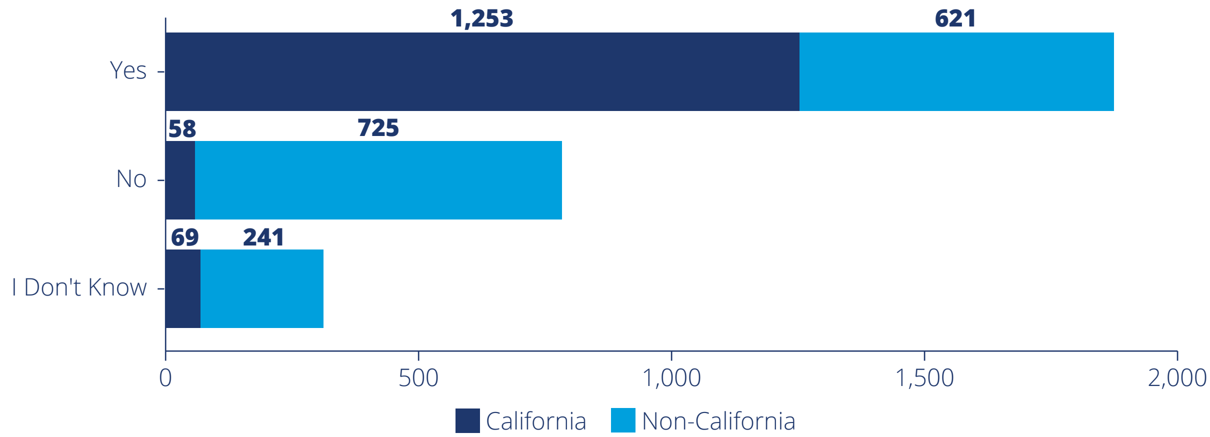
33 SECC, 2016, *Consumer Driven Technologies.*

34 Since the vast majority of time-varying rates currently offered to customers are TOU, we specifically used the term "time-of-use rates" in the survey to minimize customer confusion.

35 Non-U.S. respondents were removed from the sample prior to analysis.

36 Residential customers of these utilities currently have access to an optional TOU rate.

Figure 10: EV Customers with a TOU Rate Option (California and Non-California), by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=2,967.

available TOU rate. Nearly 40% of the non-California survey population had access to a TOU rate.

Survey Results: Enrolled TOU EV Customers and Non-Enrolled EV Customers

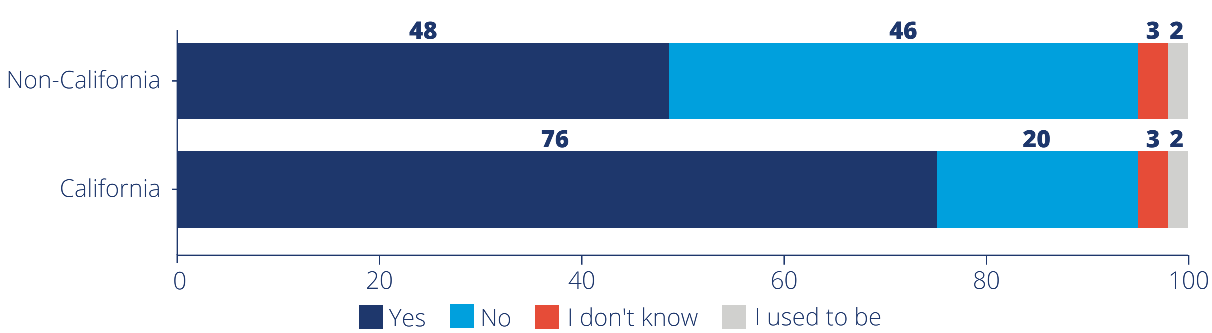
This section analyzes the survey results from two populations of EV driver groups (a total of 1,783 respondents)[37] that had an available utility TOU rate option: 1) enrolled customers and 2) customers that chose not to enroll in a TOU rate, which we term as non-enrolled.

The enrolled customers provided a variety of insights into their motivations, to what type of rate they subscribed (including generic and EV TOU rates), their level of familiarity and participation in the rate, and how they heard about the rate initially. For non-enrolled customers, the survey identified why they didn't participate and what it would take to change their mind.

A. Insights from Enrolled Time-of-Use Rate EV Customers

Among our sample, over 65% of participants in the customer survey said they are currently enrolled in their utility's TOU rate (Figure 11). Among the sample, 75% of California respondents were enrolled and nearly 50% of non-California respondents were enrolled. Of those who are enrolled in a TOU rate, 39% indicated that their TOU rate is EV-specific (Figure 12)—42% for California respondents and 30% for non-California respondents. Only 2% of EV drivers for both populations were enrolled in a

Figure 11: EV Customers Enrolled in a TOU Rate, by Percent



Source: Smart Electric Power Alliance & Enel X, 2019. N=1,880.

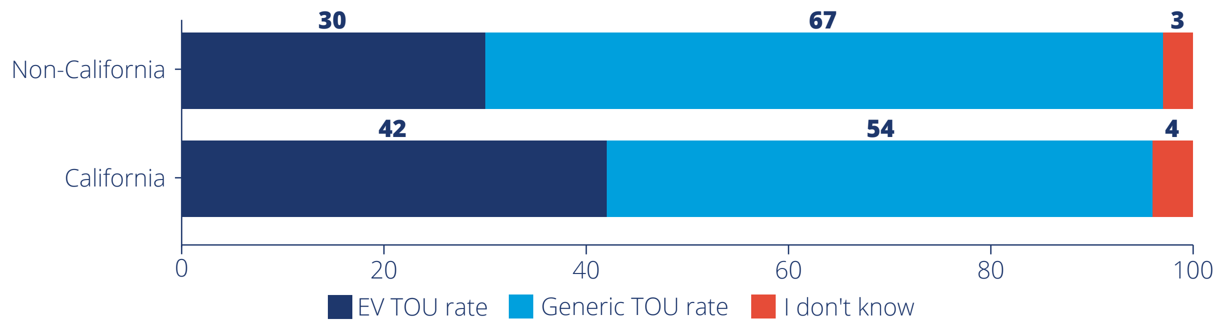
37 This population does not include respondents that did not know if they were enrolled or that were previously (and not currently) enrolled in a TOU rate.

TOU rate, but are no longer. This would suggest that once a customer enrolls, they remain on the rate.

Similar to the results from the utility survey, the Enel X survey respondents reported high levels of behavior shifting, with 87% of consumers charging off-peak 95% to 100% of the time (Figure 13). Respondents on an EV TOU rate were only slightly more likely to charge off-peak compared to their generic TOU counterparts. Perhaps more interesting, 7% more EV rate customers (including CA and non-CA) participated 100% of the time compared to the generic TOU population. This suggests that customers enrolled in a TOU rate understand how to participate and show a willingness to adjust their charging behavior.

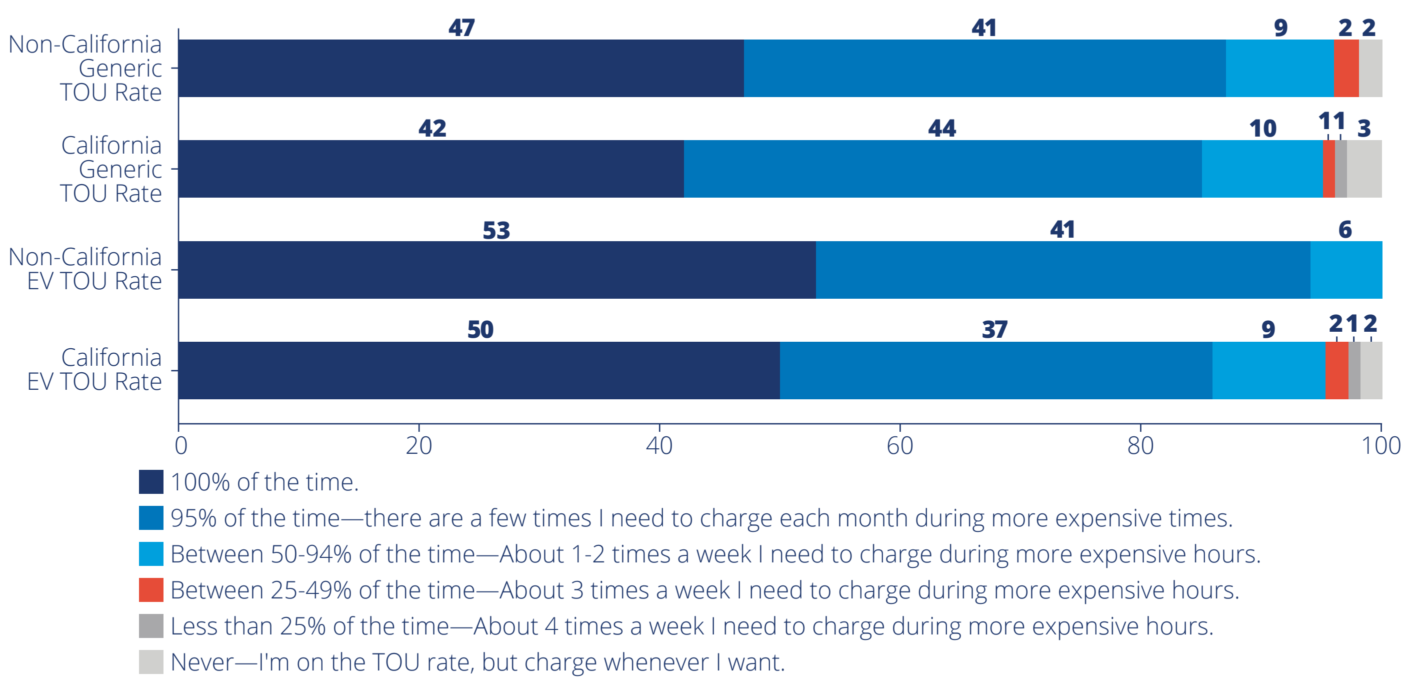
When asked how familiar the EV driver was with the rules around their EV rate, 86% (including CA and non-CA) indicated they were extremely familiar to somewhat familiar. Interestingly, EV drivers on the EV TOU rate were more familiar with their rate rules by nearly 10% (including CA and non-CA) compared to those on a generic TOU rate (Figure 14). While familiarity with these rates was high, these results suggest that utilities could do more to help their customers navigate the rules of the program—particularly with the 'somewhat familiar' group.

Figure 12: EV Customers Enrolled by TOU Type (EV or Generic), by Percent



Source: Smart Electric Power Alliance & Enel X, 2019. N=1,241

Figure 13: Average TOU Enrolled EV Customer Charge Time Done Off-Peak by TOU Type (California and Non-California), by Percent

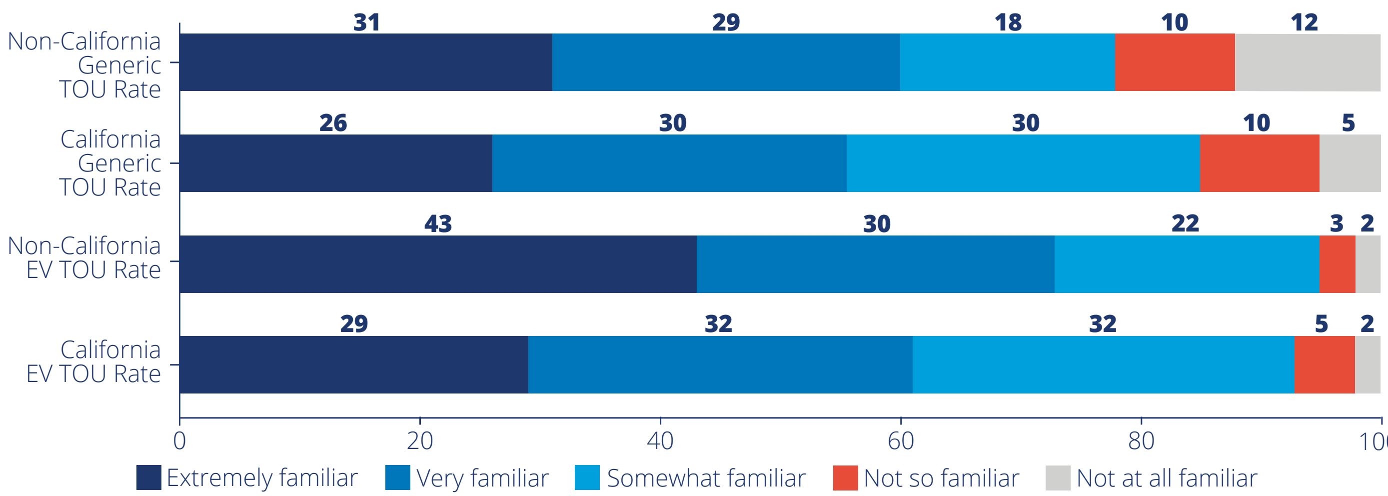


Source: Smart Electric Power Alliance & Enel X, 2019. N=1,167.

When respondents were asked why they enrolled in the TOU rate, 86% (including CA and non-CA) enrolled to save money (nearly 3x more than the next option) and for environmental benefits (Figure 15). Drivers on the EV TOU were 5 percentage points (including CA and non-CA) more motivated by savings than their counterparts on the generic TOU rate. Key for utilities is that while customers are primarily motivated by savings, environmental considerations are also important—by speaking to both of these motivations in program design and marketing campaigns, utilities can appeal to a wider range of customer types and interests.

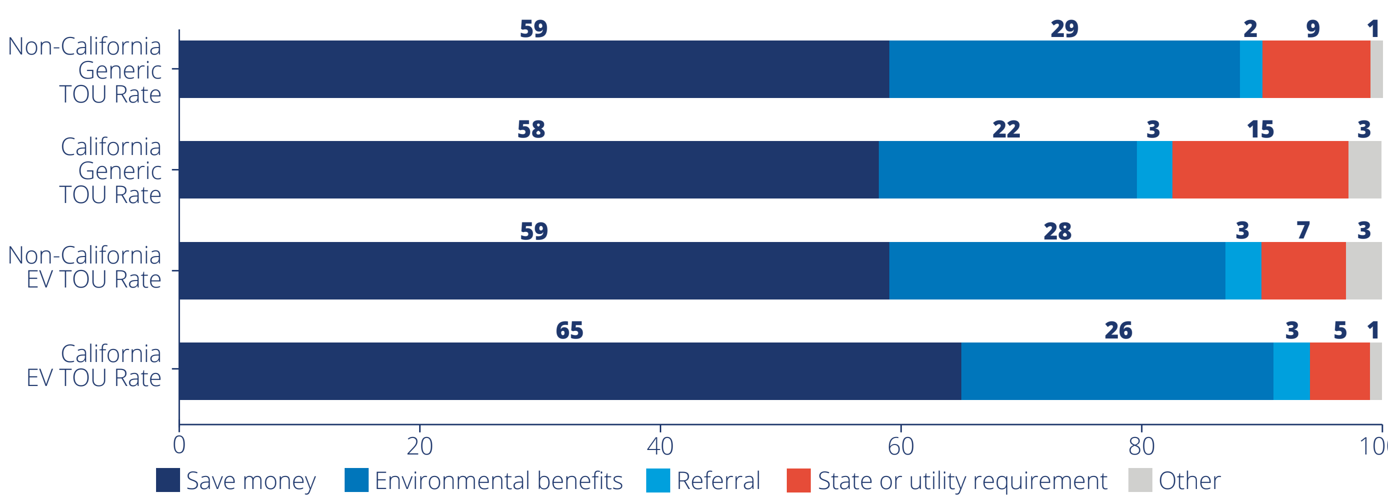
Survey respondents discovered their TOU rate through methods that are inexpensive and easy for utilities to use. Almost 70% discovered the rate through the utility website, bill inserts or flyers, and emails (Figure 16). Only 0.6% (10 out of 1,679) customers discovered their TOU rate through a ride-and-drive event. EV TOU rate participants relied more heavily on information from the utility website and through referrals than their generic TOU counterparts. There was not a significant difference between California and non-California respondents.

Figure 14: Enrolled EV Customer Familiarity with TOU Rate Rules by TOU Type (California and Non-California), by Percent



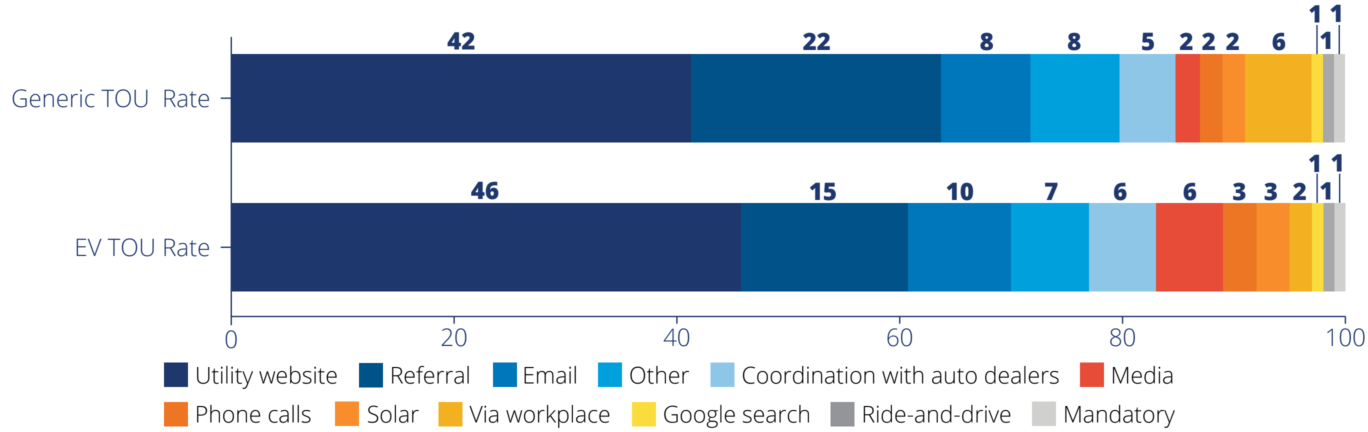
Source: Smart Electric Power Alliance & Enel X, 2019. N=1,107.

Figure 15: Motivation for EV Customer to Enroll by TOU Rate Type (California and Non-California), by Percent



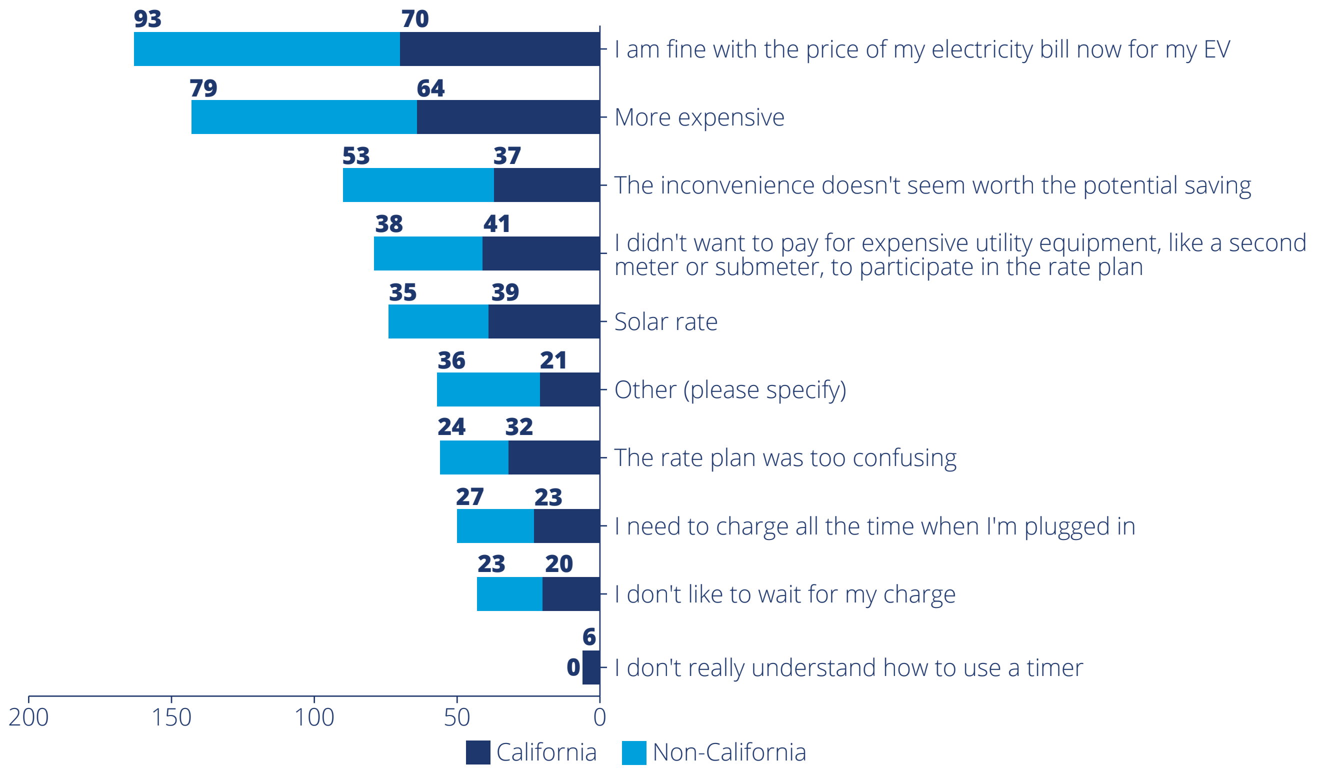
Source: Smart Electric Power Alliance & Enel X, 2019. Respondents selected all that apply. N=1,192. (1,704 options selected)

Figure 16: How Enrolled EV Customers Heard About the TOU Rate by Type, by Percent



Source: Smart Electric Power Alliance & Enel X, 2019. Respondents selected all that apply. N=1,173. (1,611 options selected)

Figure 17: Why EV Customers Did Not Enroll in a TOU Rate, by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=526. (761 options selected)
Respondents selected all that apply.

B. Insights from Non-Enrolled EV Customers

When EV drivers were asked why they didn't enroll in a TOU rate, responses indicated insufficient savings and inconvenience (Figure 17).

Regarding insufficient savings, many did not want to pay for expensive utility equipment, they thought the rate would be more expensive, or they would not save enough money due to their electricity usage behavior. Others indicated that they were satisfied with the current price of their electricity bill. Many also didn't like the inconvenience of waiting for their charge or needed to charge frequently. Responses also indicated confusion about the rate, how to use timers, and conflicts with other existing rates, like solar rates.

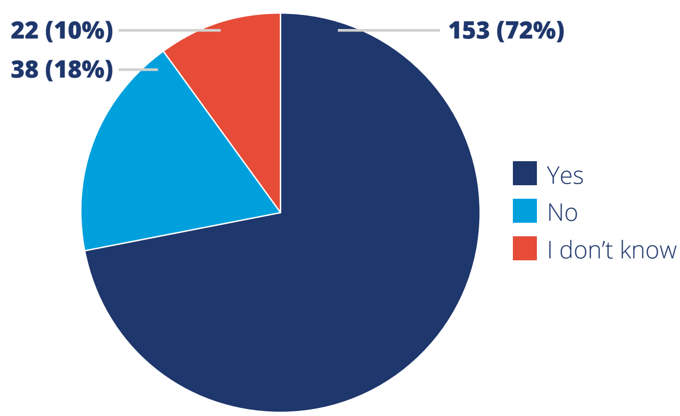
According to the survey, over 72% of non-enrolled customers were willing to charge their EV during off-peak hours (Figure 18).[38] If customers are willing to charge off-peak, but are not sufficiently incentivized by the potential savings, there must be a significant deterrent to enroll. A factor could be the perceived inconvenience of enrollment and compliance with the rate or insufficient financial incentive, as indicated in Figure 19.

Approximately 50% of respondents indicated they would need a savings of $100 or more per year to persuade them to enroll in a TOU rate, though the survey results also indicate that consumer preferences vary and not all customers are equally motivated by savings. Customers seeking more savings through their applicable rate may prefer a time-varying rate with a larger peak to off-peak ratio that offers a higher financial reward for shifting their charging to off-peak periods. Alternatively, as shown by Figure 17, some customers may be deterred by a perceived inconvenience of a time-varying rate with a higher peak to off-peak ratio or a limited off-peak period time window for cheaper charging rates. These findings suggest that it is difficult for utilities to appeal to all different customer types with only one rate design as discussed in the 'What to do about Metering' chapter.

By offering customers multiple rate options with significant variation, utilities may engage broader segments of their customer base and achieve higher enrollment rates.

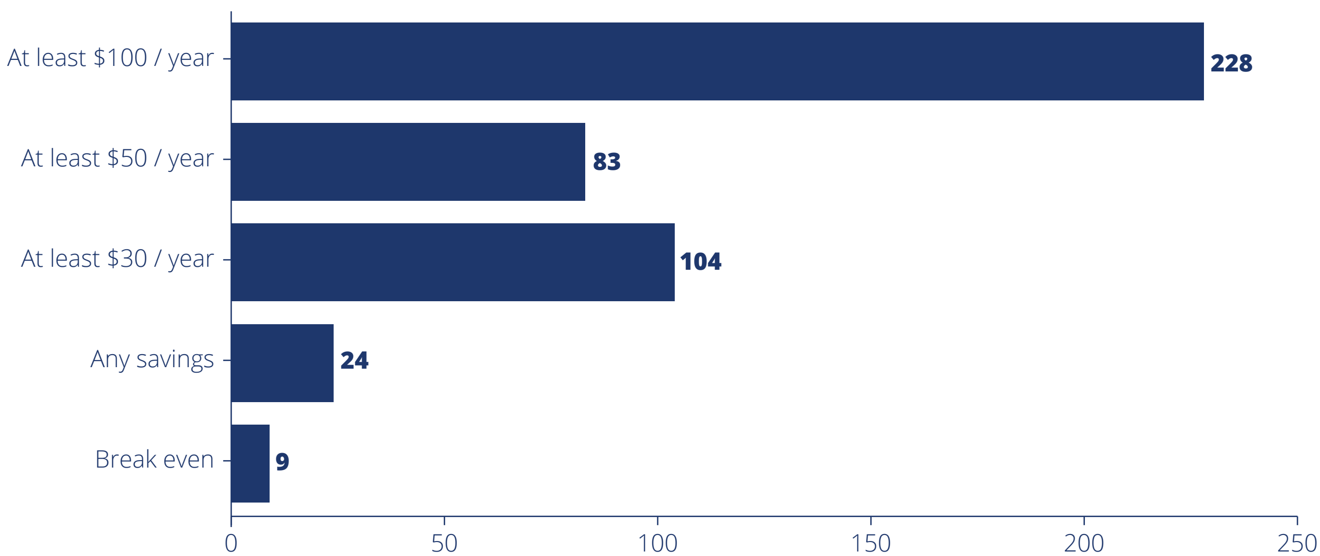
Utilities can employ behavioral programs as an alternative or supplement to a time-varying rate, in order to encourage more customer off-peak charging. Load management may be achieved through a variety of behavioral programs such as email and text alerts or education campaigns. These programs would require nominal utility investment.

Figure 18: Non-Enrolled EV Customers Willing to Charge Off-Peak, by Percent and by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=213.

Figure 19: Savings Required for EV Customers to Enroll in a TOU Rate, by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=448.

38 Note: The survey did not ask if customers were aware of the applicable off-peak hours as part of the available TOU rate.

5) Features of Effective EV Time-Varying Rates

This section summarizes the features of EV rates that contribute to the highest levels of customer enrollment. Data on customer enrollment was obtained through the utility survey, with information collected for 20 active, full-scale (excluding pilots) rate offerings. Nearly half (9 of 20 rates) reached enrollment levels of at least 25% (Figure 20). However, variation in enrollment levels is significant, ranging from less than 1% up to 80% of eligible customers (with 80% represented by Braintree Electric Light Department and highlighted in the case study in Chapter 7). Most rates in the utility survey had been offered for between two and five years with an average age of four years.

A. Utility Survey Findings

The survey identified a number of variations in rate design and marketing. Based on analysis by Brattle, some of these characteristics correlate to enrollment. Figure 21 highlights five of the attributes with the strongest relationship to high enrollment levels. In order of most-to-least influential:

1. Rates with an available **marketing budget** have enrollment 3x greater than those without (22% vs. 7%).
2. Rates driven by a **utility initiative** had significantly higher average enrollment than those offered to satisfy legislative or regulatory requirements or customer demands. Utility-driven initiatives had enrollment of over 30% compared to less than 15% for others;
3. **Rates providing bill savings** (in the absence of adjustments to charging behavior) have enrollment levels 2x higher than those with an expected bill increase;
4. Rates with **free enrollment** and no additional metering cost have enrollment 1.7x higher than rates with an additional cost to enroll; and
5. Rates that were promoted using **four or more marketing channels** have enrollment 1.4x those using three or fewer marketing channels.

These findings are intuitive, but many of the existing time-varying EV rate offerings identified in the utility survey did not include these attributes.

The length of time the rate was offered is not a relevant contributor to its achieved enrollment. Average enrollment is similar for rates that have been offered for at least four years (26%) compared to those that have been offered for less than four years (23%) (Figure 22). Offering a rate for a long period of time is not sufficient to attract customer enrollment. Rather, higher enrollment is driven by actively promoting the rate to customers through specific marketing initiatives.

According to the survey, ride-and-drive events and coordination with auto dealers were two marketing tools most significantly related to higher enrollment levels (see Figure 23). The consumer survey would indicate that ride-and-drive events were less helpful in discovering an EV rate, but this may be due to the limited number of utilities that currently offer them limiting the sample population with the opportunity to participate in an event. It's important to note that those utilities offering ride-and-drive events are using other marketing channels as well. As such, it was difficult to determine a cause and effect relationship specifically related to ride-and-drive events.

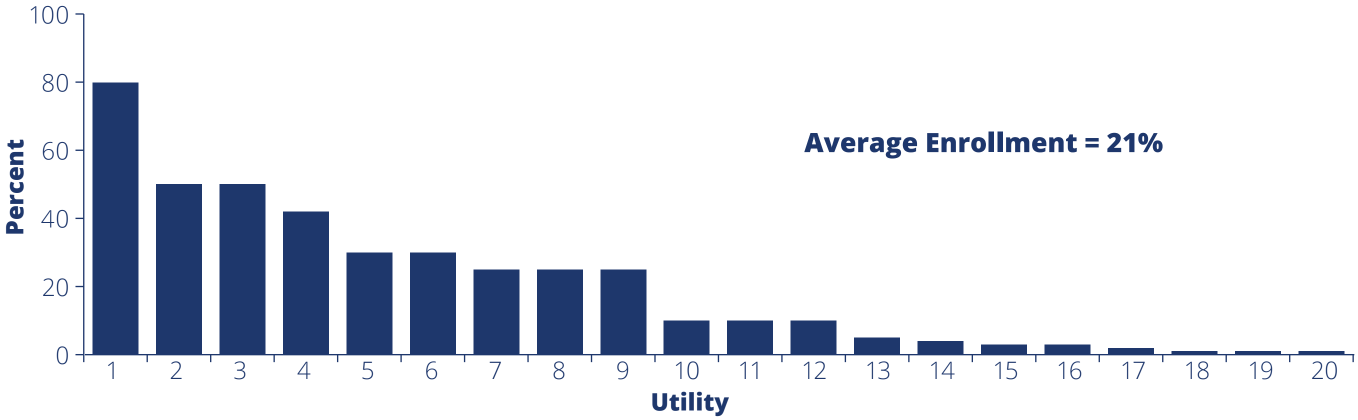
B. Utility Lessons Learned

Utility survey respondents offered lessons learned, primarily regarding customer interest, marketing, rate design considerations, and metering (discussed further in Chapter 7). EV rate design practices are in the formative stages, and the experiences of utilities with EV rates provide unique and useful insights. The following summarizes these perspectives; varied experiences sometimes produce conflicting insights.

Customer Insights and Marketing

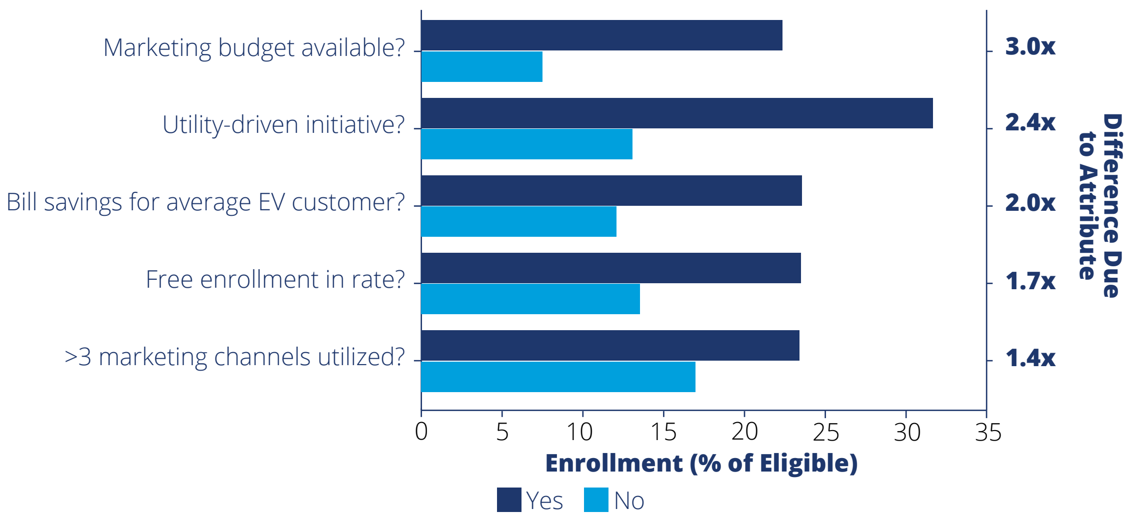
- Customer communication is key. Utilities should not depend on third-parties, such as dealers, to provide utility rate information.

Figure 20: Share of Eligible EV Customers Enrolled in the EV Rate



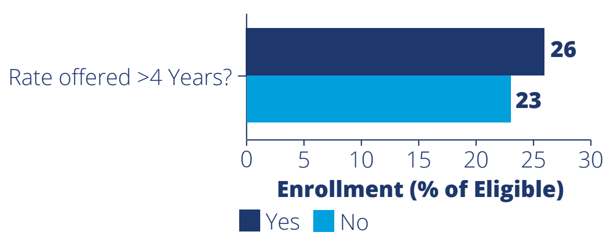
Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20.

Figure 21: Average Enrollment by Attribute



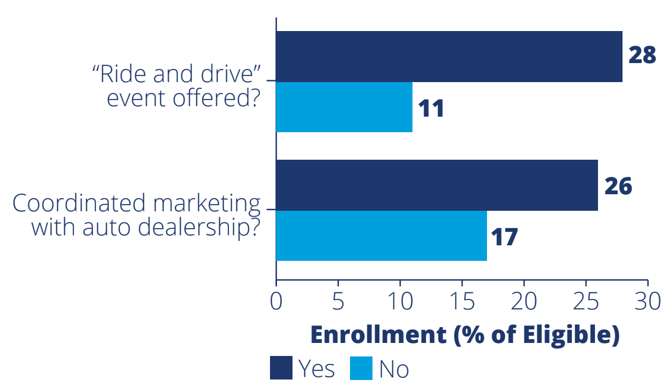
Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20

Figure 22: Rate Offering Duration Is Not a Factor in Enrollment Success



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20.

Figure 23: Rate Marketing Efforts Are Important



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20

- Creative recruitment is required, as enrolling customers is very challenging, even with large incentives and attractive rates.
- One western state utility experienced, "consistently high enrollment in their EV rate over the last 4-5 years, with approximately 25% of EV owners enrolled. This occurred with little active marketing, illustrating that customers (at least early adopters) are interested in saving on fuel costs."
- While some utilities see EV rates as a way to promote EV adoption, one utility suggested that their in-state tax credit was a bigger sales incentive. The rate might encourage those customers to charge at night, but in their state, EV sales were driven mostly by state tax incentives. Further, other rates offered by the utility (e.g., a demand rate) could yield better savings for EV drivers.
- One utility said, "customers are very satisfied with the EV rate and change their charging behavior to maximize their savings. Promote/publicize the EV rate in every way possible and practical to inform the public."

Rate Design

- One utility indicated a need to closely consider the number of hours for the off-peak rate and the price differential between the off-peak and super off-peak. In their case they had six hours in the super off-peak, but that customers preferred eight.
- One utility stated, "Customers are apprehensive to sign up for a rate that applies to their whole house usage as opposed to just their EV charging behavior." Other utilities felt the opposite was true, due to customer apprehension about additional metering costs.
- Utilities also recommended building flexibility into the rate to accommodate changing grid conditions, such as a shift in the timing of the net system peak demand due to growing solar PV adoption.
- Though some utilities are concerned about eroding profitability through favorable off-peak pricing, one utility stated, "Even with a fairly high on-/off-peak differentials, enough usage occurs during peak that revenue is not as severely compromised as some expected."
- As previously noted, the cost to participate is a major factor in enrollment. One utility stated, "Customers are sensitive to up-front costs to participate in the program."
- Another utility found that a one-size-fits-all approach will not work. They suggest giving customers options that help them save money on their EVSE and metering costs. They also suggested using company-provided electricians to help customers set the charging schedule on their vehicles or in the chargers, which increased the possibility of 96% off-peak charging.
- From one utility's perspective, they thought a discount during off-peak hours was a better alternative than increasing the price during the peak period.

Metering

- Utilities had varying opinions about the most effective way to meter and bill customers under a time-varying EV rate. One utility felt that submeters were the most effective metering method for EV time-varying rates given the wide variety of charging equipment options available to customers. Another utility felt that a submetered rate was successful at influencing charging behavior, but at a cost to the customer and the utility. They stated, "Managing that cost will be the primary hurdle to deploying submetering. It is still unclear how much more effective a submetered rate would be at influencing behavior when compared to a whole house rate." A different utility suggested to not mandate a submeter, which for them, resulted in hundreds of extra dollars in cost of installation. They felt that a better alternative was to "require a smart EV charging station that could communicate and send the utility the off-peak usage data to provide an 'incentive' check each month or quarter."
- A utility shared on second service metering options, "a separately metered EV rate is largely unpopular among EV owners. The added cost, time, and effort of adding a separate service is not attractive, and there are not easily apparent savings compared to the whole-house rate, which had similar pricing."
- Another utility stated that due to the unpopularity of the up-front costs for second service, they were piloting other services/technologies, though "the second service is the more economic option.. [for example] cases with detached garages and a fully loaded existing service panel in the customer's home."
- "Whole house EV rates seem successful at influencing behavior, but prevents visibility into specific charging behavior. These rates are relatively straightforward to deploy," was the opinion of another utility.

Notably, the top three drivers of time-varying EV rate enrollment are all factors the utility can control, including:

1. **Residential EV rates that offer customers the opportunity for savings compared to the standard rate:** EV rates must provide customers with an opportunity for financial savings, in order to be attractive to customers. Rates should be designed such

that the price signals are transparent and actionable, so customers have the information necessary and a sufficient incentive to shift their charging load to designated off-peak periods. Rates that are successful in encouraging off-peak charging behavior lower the utility's cost to serve, resulting in lower prices for customers.

2. **No additional metering charge or customer investment required:** The up-front costs associated with any of the metering options, for example a second meter or a submeter, was identified by several utility survey respondents as a deterrent to enrollment. One option to overcome this barrier is to include the customer's entire home load under the time-varying rate, minimizing the initial investment. However, some customers may not want to subject their entire home load to a time-varying rate.This presents a catch-22 for rate analysts. Creative rate design offerings are needed to overcome this tension. For example, the combination of a whole-house meter that does not differentiate by time, and a smart charger that reports TOU data for the EV consumption, can address this.
3. **The rate is promoted via a dedicated marketing effort:** To maximize enrollment, the rate should be promoted when customers are most engaged. This can be achieved at dealerships and ride-and-drive events when customers are making the EV purchasing decision, by electricians and charging station installers when customers are thinking about charging costs, and by tying enrollment to eligibility for utility-sponsored EV rebates or charging infrastructure purchases. This ensures the consumer is aware of the rate early in the process. **Typically, once the EV is purchased and the charger is installed, customer engagement is reduced and "momentum" towards the EV time-varying rate enrollment is lost.**

6) What To Do About Metering

There are many important rate design program considerations, but one of the most important is the meter. The available metering configurations influence the type of rates than can be offered to customers, the costs of enrollment, the type of administration, the ease of integration with existing billing systems, the security and reliability of charging signals, and the adaptability of the program to handle future EV technology changes. There are five basic ways to meter and bill residential customers for EV time-varying rates. The pros and cons for each are discussed in the section below and presented in Table 7.[39]

1. **Existing Meter:** This is used for a whole house rate, and leverages the existing meter.
2. **Second Meter:** This would be for an EV-only rate and requires a second service and the necessary home wiring, in addition to the customer's existing residential service.
3. **Submeter:** This would be used for an EV-only rate and would be connected to the primary meter, and may not require similar additional home wiring.
4. **EVSE Telemetry:** Utilities could leverage 1) built-in EVSE telemetry routed to the utility through the vendor/ network service provider or 2) the EVSE would send data to the utility via AMI backhaul enabled by Power Line Communication (PLC) (e.g., Zigbee, GreenPHY).
5. **Load disaggregation:** Utilities would collect primary meter data and use an analytical tool to disaggregate the load and identify the portion used by the EV. This could also be accomplished with the assistance of a device, such as a meter collar.

Utility approaches to metering varied across the sample set. As new technologies providing improved capabilities emerge, those options will continue to expand. This section highlights utility approaches to metering today, the pros and cons of specific approaches, and case studies highlighting utilities that have developed innovative rate programs via their metering approach.

39 In addition to the evaluation of metering options in Table 7 and discussed throughout this section, utilities must also consider the relevant statutory and regulatory requirements applicable in their jurisdiction. Some metering configurations presented in this report may not be covered or allowed by existing statutes and regulations. For example, the Maryland Public Service Commission recently granted a temporary waiver of certain regulations governing the submetering process to the investor-owned utilities in the state for a five-year EV portfolio program. By granting the temporary waiver, the utilities can utilize customer EVSE devices as electric submeters for billing purposes without violating Code of Maryland Regulations. For more information, see Order No. 88997, "In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio", Public Service Commission of Maryland, Case No. 9478, January 14, 2019.

A. Utility Approaches to Metering Vary

Utilities with active EV time-varying rates (see list in Appendix A) have employed a variety of approaches to metering and billing of EV charging load. Of the 64 EV rates, 43 used the primary meter (of which one used load disaggregation), 28 had a second meter, and 7 used a submeter (of which 2 were through the EVSE) as shown in Figure 24. Thirteen of the rates allowed more than one option under the same rate tariff.

It is important to note that the project team was unable to identify a correlation between the metering configuration and enrollment levels. As discussed in Table 7, challenges exist with all metering approaches, but utilities can develop creative solutions that help consumers meet their needs. For example, Braintree Electric—one of the featured case studies in this section—successfully enrolled 80% of EV customers in a whole home rate using load disaggregation to incentivize off-peak charging through a retroactive incentive payment (also known as an off-peak credit). Utilities also overcame metering limitations through effective marketing strategies.

Using a whole-house meter avoids the costs of installing a second meter or submeter, however, it requires the entire home to be on the same rate as the EV. This creates customer concerns about bill increases or potential inconvenience related to changing behavior. While there are some tools customers can use to mitigate these concerns, a preferable solution may be to use a secondary meter or submeter to separately bill the EV portion of the consumption. However, it is important to address how to recoup the equipment and installation costs for the secondary meter or submeter through cost recovery.

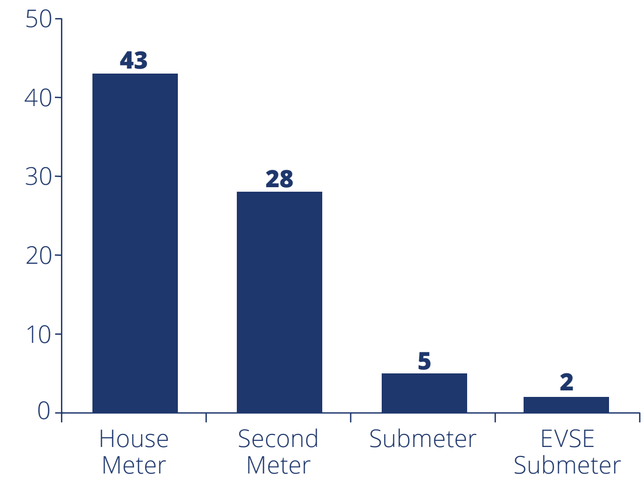
There are two options for cost recovery:

1. collecting the costs directly from the customer (this could be via a lump-sum fee or monthly charge) or
2. socializing the costs across a broader group of customers.

According to the utility survey, 50% recovered the costs directly from the EV rate customer (in a lump sum fee or a monthly charge) and the other 50% recovered from all customers.[40]

Alternatively, utilities could leverage the primary smart meter through whole-home rates or load data disaggregation techniques to provide a more accurate accounting of EV charging load. One such technique, known as non-intrusive load monitoring (NILM) has been developed to disaggregate load components based on historical data of load signatures. These techniques become considerably more accurate when load data is collected in sub-hourly intervals. An example of this is highlighted in the Braintree Electric Light Department case study.

Figure 24: Metering Configuration for EV Rate Population



Source: Smart Electric Power Alliance, 2019. N=64
Note: The authors did not identify AMI vs. non-AMI meters.

While there are potential benefits of using the telemetry in the EVSE, including lower submetering costs and customer choice, a major challenge is providing the data from an independent vendor/network service provider to the utility billing system. The integration is often costly and varies from utility to utility. Open standards will assist in lowering these costs but have not yet been implemented. The data needs to be in the proper format, and the business processes to use it have to be aligned, as well (e.g., timing of data delivery, rules for dealing with missing or invalid data, how the data file transaction occurs—i.e., how is it started, how is data receipt confirmed). Additional information about using the EVSE telemetry can be found in the Xcel Minnesota and San Diego Gas & Electric case studies in Section C.

40 Based on utility survey. N=12

Table 7: Pros and Cons of Different Metering Approaches

	Existing Meter	Secondary Meter	Submeter	EVSE Telemetry	AMI Load Disaggregation
Ability to Meter EV Charging Separately	No—Does not separate the EVSE from rest of load	Yes	Yes	Yes—Accuracy for billing purposes depends on EVSE manufacturer	Yes—Accuracy depends on ability to identify unique kW signature of EVSE
Utility Bill Integration	Easiest to integrate	Easiest to integrate	Easier to integrate	Difficult to standardize among multiple vendors and retroactively integrate into billing system; data via AMI backhaul more accurate	Depending on the format of the disaggregated data, may not integrate
Consumer Participation Cost	No additional cost	Depending on tariff, no up-front cost to consumer, or consumer pays for the full cost	Depending on tariff, no up-front cost to consumer, or consumer pays for the full cost	No additional cost if consumer already purchased the equipment; potential additional cost for compatible EVSE	Depending on tariff, some cost for administration, third-party costs, or equipment
Volume of Eligible Customers with AMI	Highest—independent of EVSE type	Highest—independent of EVSE type	Highest—independent of EVSE type	Limited to eligible EVSE vendors	Highest—independent of EVSE type

Source: Smart Electric Power Alliance, 2019.

B. Pairing Rates with Meters: Offering Customers More Choices

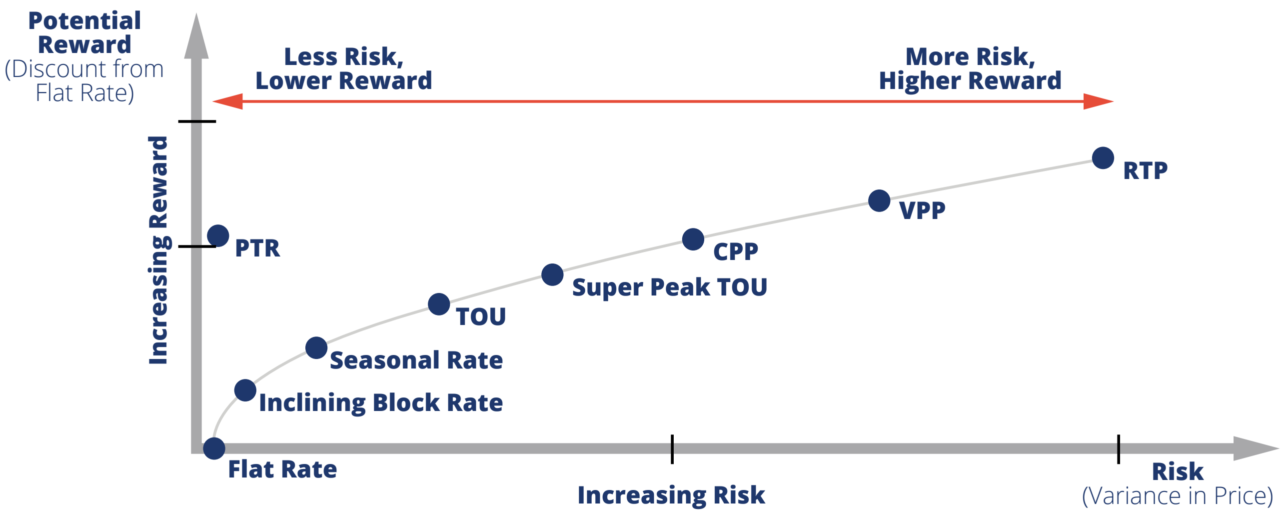
Rather than focusing on identifying a system-wide metering solution, utilities and customers may be better served by a combination of rate and metering configurations. As highlighted above in Table 7, and further explained below in the utility case studies, each type of rate offering and metering configuration offers advantages and disadvantages for utility implementation and customer appeal. For example, a separately-metered EV-Only rate option may allow utilities to design a rate to convey price signals specific to customer EV usage patterns. A benefit of this option is that utilities do not have to consider other household appliances and load in the design of the rate. Likewise, customers will not be required to adjust their non-EV residential energy consumption in order to maximize savings under the rate. This flexibility could allow the utility to design a rate that appeals to EV customers with higher financial risk tolerances by offering a TOU rate with a higher peak-to-off-peak price ratio or a dynamic pricing rate.

When considering time-varying rate options, financial risk-reward trade-offs are associated with each rate that utilities consider, as not all customers will tolerate the same risk (see Figure 25). According to the Regulatory Assistance Project, "rates offering the most reward (in terms of bill savings potential) are also the most risky (in terms of exposing the customer to the volatility of wholesale electricity markets). Which rates customers select will be determined by their risk tolerance."[41]

Alternatively, a whole-house rate may offer utilities a more forward-looking approach to encourage customer off-peak consumption for not just their EV, but other energy-intensive appliances such as electric water heaters. As rate designs continue to evolve and technologies mature, utilities may find that more complex and comprehensive "smart house" rates—providing grid-integrated water

41 Regulatory Assistance Project and The Brattle Group, July 2012, *Time-Varying and Dynamic Rate Design*, https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

Figure 25: Conceptual Representation of the Risk-Reward Tradeoff in Time-Varying Rates



Source: The Brattle Group, 2012.[42]

heating, smart thermostats, smart laundry, and smart charging as a package, for example—offer an appealing opportunity for grid benefits and customer savings in addition to technology or appliance-specific rates.

The best metering configuration for a customer is influenced by multiple factors, such as pricing, their rate structure (e..g, TOU or a dynamic rate), applicable enrollment or equipment fees, and the hours designated as peak and off-peak time periods. In addition to a customer's financial risk tolerance, utilities also need to consider important behavioral considerations, such as work schedules and the flexibility to shift electricity consumption to designated off-peak hours for particular appliances or for the entire home. These factors interact, and can represent an array of different EV customer "types" (Figure 26). Examples could include:

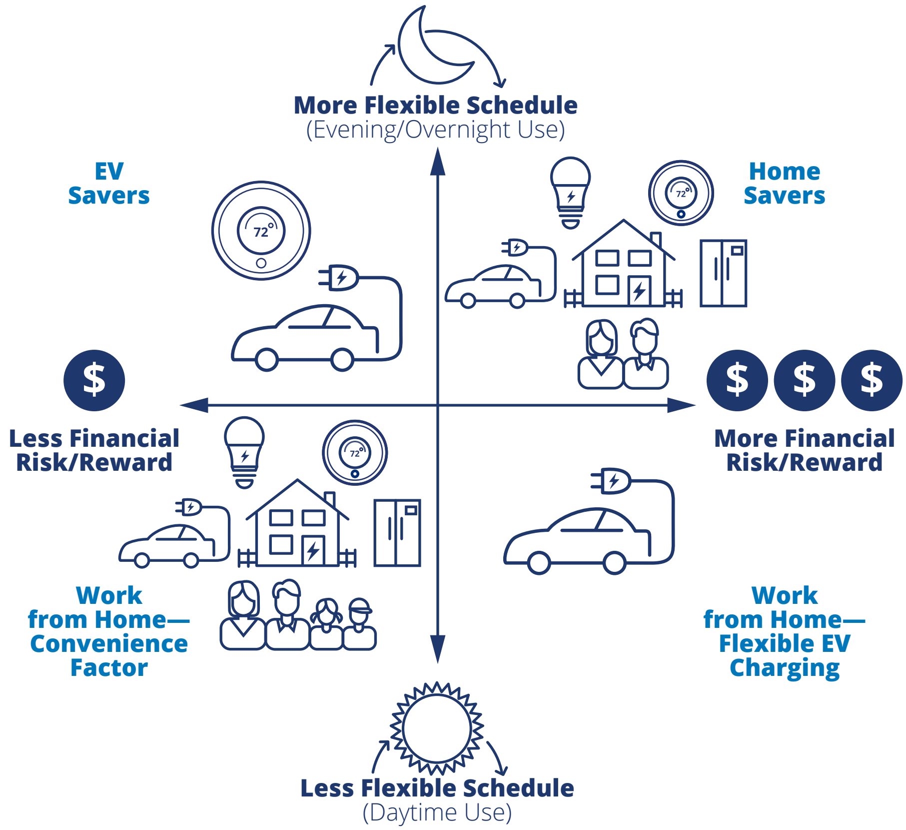
- **"Home Savers"—Outside the house during the day:** Households with more flexibility to shift entire household load to the off-peak hours and a strong interest in savings (Potential Solution: Whole House time-varying rate).
- **"EV Savers"—Outside the house during the day:** Households with flexibility to shift some load to the off-peak hours but less interested in savings, and more concerned with avoiding higher prices for entire household consumption (Potential Solution: Separately-metered time-varying rate for EV Only + other select household appliances).
- **"Work from Home"—Flexible EV charging:** Households with less flexibility to shift entire household load to avoid on-peak usage, but still have a strong interest in savings (Potential Solution: Separately-metered time-varying rate for EV only).
- **"Work from Home"—Convenience factor:** Households with less flexibility to shift entire household load to the off-peak hours and are more concerned with avoiding higher prices for on-peak usage (Potential Solution: Participate in a retroactive bill credit program.

As previously highlighted, a number of utilities offer their customers multiple rate and metering configurations for their home charging. Of the rates surveyed, 13 allow for more than one metering configuration under the same rate schedule. The most common pairing is a Whole House TOU rate (serviced on a single home meter) and a separately-metered EV-only TOU rate.

In addition eliminating barriers to participation, such as up-front costs or fees for customers, utilities can encourage higher enrollment by offering customers different rate and metering configuration options that appeal to a wider group of customer types and preferences across their service territories.

42 Regulatory Assistance Project and The Brattle Group, July 2012, *Time-Varying and Dynamic Rate Design*, https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

Figure 26: Illustrative EV Customer "Types"



Source: Smart Electric Power Alliance, 2019.

C. Utility Metering Case Studies

It is worthwhile to explore options to 1) integrate EV charging data into a utility billing system at the lowest cost, 2) increase convenience and satisfaction for the customer, and 3) ensure accuracy, reliability, and security. The following case studies feature innovative utility programs that implement different metering methods, specifically for:

1. Submeter (Indiana Michigan Power)
2. Submeter—EVSE telemetry (San Diego Gas & Electric)
3. Submeter—EVSE telemetry (Xcel Energy Minnesota)
4. Second meter—subscription rate (Austin Energy)
5. AMI load disaggregation (Braintree Electric Light Department)

The case studies discuss these integration opportunities, and highlight rate design and program implementation opportunities. These were among the most innovative programs identified in the survey.

1) Submeter: Indiana Michigan Power Leveraging Smart Meter Networks

Indiana Michigan Power—a subsidiary of American Electric Power (AEP)—found that EV customers want to know two things from their utility company: 1) how much it costs to charge their vehicles, and 2) if the utility offers incentives for charging. According to AEP, many EV owners either receive charging hardware with their vehicle or purchase directly from a retailer, and therefore may not need or want utility program-specific charging hardware.

One of the first decisions customers make after buying an EV is how they charge at home. Some customers are content with level 1 charging, others use the level 2 cordset chargers that come with their car (e.g., Tesla, Nissan, Audi) and install 240 volt service, while some others purchase a more sophisticated networked level 2 charging station. Regardless of the charging hardware chosen, EV owners can easily schedule charging through the car's in-dash screen, automaker apps, third-party apps, and even through digital voice assistants.

Given this ease of scheduling charging, customers will typically schedule their charging on nights and weekends if given a price signal. AEP has found TOU pricing to be very effective for shifting EV load to off-peak times.

AEP has identified a problem with offering only whole-house TOU rates in that they often require other customer behavioral changes related to heating and cooling that can hinder customer adoption. Instead, allowing customers to meter only their EV charging with an EV-only TOU rate can remove the customer apprehension around whole-house TOU rates.

AEP evaluated options for metering EV-only TOU rates:

- Via networked charging stations
- Through a separate utility service connection
- Using an EV-specific AMI submeter

AEP evaluated each option, considering cost, accuracy, security, communication reliability, billing integration, and other factors.

For the option of metering through network charging stations, they found challenges with:

- The reliability and security of customer Wi-Fi when communicating with the chargers.
- The difficulty of integrating charger network data with their existing utility CIS/billing system, which can be expensive to modify. Receiving usage files from a variety of network operators would require manual billing. This can result in mismatched time stamps, missing data due to loss of Wi-Fi connection, and significant opportunity for errors.
- The potential expense of accessing managed charging networks, including unpredictable network fees with uncertain future increases.
- Requiring customers to buy a utility-specified charger and utilize the associated network as a condition of program participation, which the customer may not need or want.
- The ability to adapt to future changes as the EV market evolves. OEMs are increasingly including level 2 cordset chargers as standard equipment with their vehicles, so the utility programs need to accommodate this change.

When considering establishing a separate utility service, AEP found that other utility programs incurred high administrative and equipment costs. The additional service increased costs for customers by requiring additional electrical hardware, incurring a second 'customer account charge', and duplicating other costs. They concluded this wasn't a cost-effective option for their customers.

When evaluating the use of an EV-specific AMI submeter, AEP found many benefits:

- The meter meets the regulatory accuracy requirements for billing tariffs.
- The security of the meter hardware and the interface with AEP's systems is inherent.
- Use of the existing AMI RF communications network is reliable.
- Integration with CIS and billing systems doesn't require significant IT investment or expensive manual billing.
- The purchase price of the meters is reasonable under existing utility-scale purchase volumes.
- The solution avoided exposure to unknowable future charger network access fees.
- AEP could potentially leverage the basic on/off control functionality of the AMI submeters for active-managed charging in the future, if that is needed.

For the customer, this solution avoids the need to completely adjust their behavior to accommodate a whole-house TOU-rate, or to purchase a utility-specified charger. It also allows customers to choose how they wish to control their vehicle charging. AEP found this approach to be the simplest, most convenient, adaptable, and lowest cost option.

2) Submeter—EVSE Telemetry: San Diego Gas & Electric (SDG&E) Power Your Drive

SDG&E developed the Power Your Drive pilot program aimed at workplace and multi-unit dwelling property owners to encourage increased EV adoption, especially in communities of concern. Once the chargers are deployed, EV drivers at the sites can sign up and gain access to over 3,000 charging stations at over 250 locations. The program has a special pricing plan that offers lower prices during grid-friendly times such as times of high renewable penetration or low grid congestion. Customers can set a maximum price to charge their EV. When the hourly price exceeds the maximum price, charging stops.

In the development of this rate, SDG&E tackled challenges of both diversity between circuit and system peaks, as well as diversity of peaks and load shapes across different circuits, while ensuring all customers are treated equitably. Because the program targeted specific locations, locational pricing was a concern for regulators. If a utility charged solely based on load, it could create inequity from one location to another. To address this, SDG&E used a critical peak price (CPP) concept and incorporated circuit level pricing. By applying the same price to every circuit, they resolved the issue of equitable pricing for customers across locations.

Each location has the exact same pricing structure, but at different times.

When examining time-varying rate options, Cyndee Fang, manager of energy research and analysis at SDG&E, recommends utilities ensure that the options they provide customers are purposeful, which may mean a limited number of choices but making the choices meaningful for the customer. Too many rate offerings can be confusing and too few fail to address specific customer needs. A static time-of-use rate is best for customers who are able to shift usage out of defined high cost hours, whereas dynamic rates help customers who are more responsive to tap into additional savings.

Hannon Rasool, the clean transportation business development manager at SDG&E, stated that, "submetered[43] EV-only rates allow for more complexity in the rate design as they require fewer human behavioral adjustments around the home." Given the potential size and flexibility of EV loads, an EV-only rate provides the opportunity to create a rate that is flexible and forward looking. "If you can get the design out there, people are able to get the technology to match the rate design," said Fang.

Rasool added that utilities planning to develop an EV-only time-varying rate should be focused on incorporating the EV load to the grid in a manner that doesn't increase costs. "Proper rate design can help save money and achieve the environmental benefits we all want to see. Utilities planning an EV program should look into how they can incorporate the additional load into the grid and that is where actionable rate signals really matter," said Rasool.

A significant opportunity provided by SDG&E's rate is that despite its complexity, it is a more dynamic rate offering and opens up more low-cost hours for flexible loads such as EV charging. This makes it meaningful for customers, and gives them choices. "Utilities have to be mindful about options put out there and ensure they bring value for customers," said Fang.

3) Submeter—EVSE Telemetry: Xcel Energy Minnesota Residential EV Service Pilot

Xcel Energy Minnesota launched a Residential EV Service Pilot in 2018 offering an EV TOU rate that leveraged networked Level 2 charging equipment to lower the initial cost to enroll.[44] The pilot was designed to test the potential for cost savings and improved customer experiences through a combination of new equipment deployment and off-peak rate design. By leveraging the telemetry capabilities of the EVSE, utilities could use charger equipment to provide billing-quality data. The program avoided the need for customers to pay for the installation and cost of a second meter. In addition, the pilot improved the customer experience while maintaining a safe and reliable electricity service.

The pilot was capped at 100 participants with average savings of the cost of EVSE and metering installation of $2,196 per customer compared to the costs associated with equipment and installation for the separately metered option.[45] Actual savings were dependent on the availability of an existing 240 volt dedicated circuit needed for the Level 2 charger as well as proximity to the garage, panel location, and circuit pathway.

Xcel Energy offered customers chargers from two EVSE manufacturers, ChargePoint and Enel X. Xcel Energy found that while the data provided by the charging equipment was sufficiently accurate, formatting the data so it could be received by the company and successfully uploaded to the billing system required significant collaboration with the vendors. Moving forward, Xcel Energy plans to explore ways in which it can improve integration and operations between its systems and charging equipment options.

The pilot resulted in a 96% of the charging load was off-peak. Based on an assumption of 350 kWh of usage per month and the current level of off-peak charging, enrolled customers would save $9.76 per month or $117.12 per year on the TOU rate.

The pilot provided a positive turn-key customer experience for electric vehicle charging in the home, with customer satisfaction scoring 87% for enrollment and 95% for charging equipment installation. From the 63 survey responses, Xcel Energy also identified areas for improvement, including explaining rate pricing, communicating with customers, and providing information about the charger options. While customers understood and recognized the pricing signal (in that charging their EV during off-peak hours is cheaper and provides benefits), they were confused about the pricing, components of the rate and on-bill presentation, as well as the expected

43 In PYD, SDG&E used data collected from submeters in the EV chargers for billing after qualifying the submeters through a rigorous testing process. Two chargers were accepted, from Siemens and ChargePoint, meeting the testing criteria of +/- 1.0%.

44 Note: This pilot was intended for customers who wanted a new EVSE at their home. Xcel has other rate options, such as a whole home TOU, for customers that prefer level one charging, a non-networked charger, or other options. Additional information about the program is available in the *Residential Electric Vehicle Charging Tariff Docket* No. E002/ M-15-111 and E002/ M-17-817, 2019.

45 The savings are measured by asking electricians to provide the customer with (at least) two estimates for wiring their home—one being a separate service/meter, one being a dedicated circuit behind the customers main panel/existing meter. Xcel identified the difference between these estimates as the savings vs the existing separately metered rate.

fuel savings and payback period for their investment. Xcel Energy plans to leverage digital tools and more comprehensive energy consumption data to provide customers with better insights into the benefits.

Seventy-three percent of participants in the EV Service Pilot preferred to pay for the charging equipment and installation through a bundled monthly charge, instead of the prepayment option, indicating that customers prefer to reduce upfront costs and simplify participation. Xcel Energy plans to adjust the tariff as needed and experiment with subscription models.

4) Second Meters: Austin Energy EV360 Subscription-based Rate

In 2015, Austin Energy developed three new pilot rates with the goal of offering customers more rate options. Along with an EV-only subscription rate, a prepayment rate and a whole-home Time-of-Use rate were piloted. The subscription, titled EV360, offers customers with a capacity demand of less than 10 kW the ability to use unlimited off-peak (7pm-2pm weekdays, anytime during weekends) kWh's for EV charging for a fixed monthly fee of $30.[46] Customers with demand over 10 kW have a fixed monthly fee of $50. Customers are able to charge on-peak, but will incur a bill adder of $0.14/kWh during the winter and $0.40/kWh during the summer.

The subscription coupled TOU-like hours with a fixed charge to give EV customers a predictable bill. To date, the rate has resulted in 99% of participants using off-peak electricity. However, Austin Energy has yet to determine how much it has changed charging behavior beyond initial survey data.

Lindsey McDougall, the Program Manager for the EV360 program, published a report in September 2019 which highlighted key takeaways and lessons learned from the pilot program.[47] A key element of the pilot's success was educating customers. Participation required a large investment by the customer, as they had to install both a conduit and meter socket for the meter, obtain a permit, and hire an electrician. This meant the pilot was limited in reach, with those interested in participating being well-educated and eager to participate. Pilot participation required significant guidance from the utility. Austin Energy worked closely with EVSE installers to inform them about the program and created an "Installers tab" on their website.

As EV360 was a small pilot with 100 participants, management and administration of the program was performed by one person—Lindsey McDougall. While manageable for a small pilot, if Austin Energy decides to offer the rate to all customers, additional staff would be required, as well as training the call center to handle customer inquiries.

Reflecting on the pilot, McDougall noted that subscription rates will be important to EV drivers and utilities. "EV drivers charge off-peak for green initiatives and cost savings and utilities will be expected to have the same values. Consequently, there will be huge demand for utilities to not penalize customers for having an EV, but instead having rate structures that encourage conservation where possible."

In addition to EV-only rates, McDougall also noted that subscription structures could apply to other scenarios, for example the whole home. "Especially with distributed energy service providers, utilities will see a more dynamic relationship between energy resources and consumption. There will become a two-way channel between the utility and the customer."

5) AMI Load Disaggregation: Braintree Electric Light Department (BELD), Bring Your Own Charger®

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. Typically gathering energy consumption data in 15-minute intervals, AMI meters can generate vast amounts of data, with the exact data varying based on utility and system.

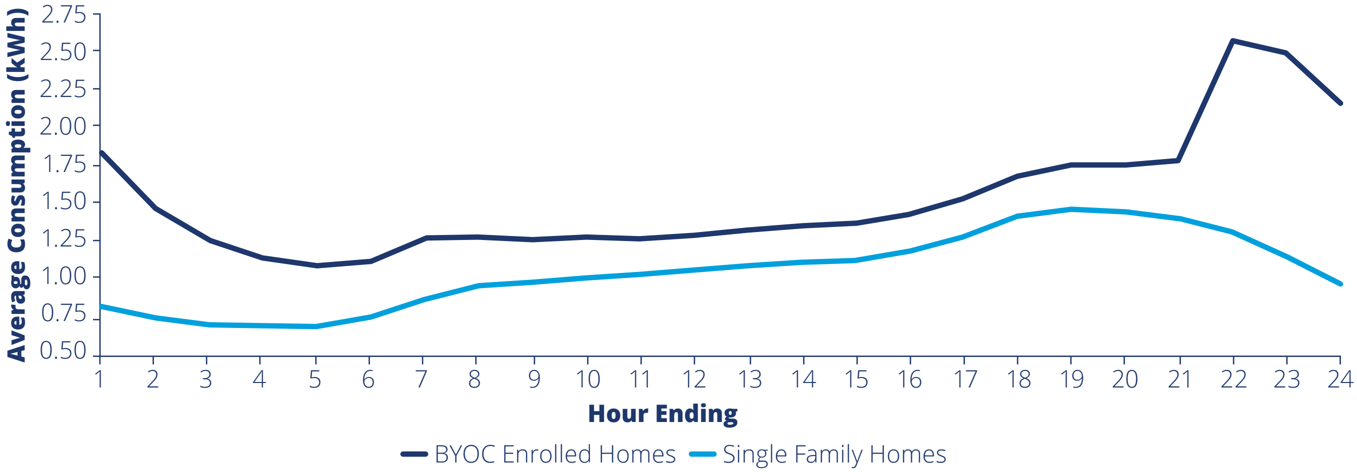
BELD launched Sagewell's Bring Your Own Charger® (BYOC) electric vehicle load management program in 2017, and has approximately 80% of known EVs in their service area under load management. The BYOC program does not require any load control hardware because it utilizes AMI meter data to verify off-peak charging compliance.

BELD began residential EV load management three years ago, initially focusing on load control through EV smart chargers. However, they quickly identified difficulties in getting a significant volume of smart chargers installed and high program costs as key obstacles and transitioned to Sagewell's non-hardware-based BYOC solution to

46 Additional details about the rate design are on page 7: Austin Energy, EV360 Whitepaper, *Austin Energy's Residential "Off Peak" Electric Vehicle Charging Subscription Pilot: Approach, Findings, and Utility Toolkit*, https://austinenergy.com/wcm/connect/b216f45c-0dea-4184-9e3a-6f5178dd5112/ResourcePlanningStudies-EV-Whitepaper.pdf?MOD=AJPERES&CVID=mQosOPJ.

47 See Austin Energy, EV360 Whitepaper, *Austin Energy's Residential "Off Peak" Electric Vehicle Charging Subscription Pilot: Approach, Findings, and Utility Toolkit*, https://austinenergy.com/wcm/connect/b216f45c-0dea-4184-9e3a-6f5178dd5112/ResourcePlanningStudies-EV-Whitepaper.pdf?MOD=AJPERES&CVID=mQosOPJ.

Figure 27: Identifying the Load Profile from Average Enrolled EV Home Compared to Average Single Family Home in Braintree



Source: Sagewell Bring Your Own Charger (BYOC), 2019.

monitor EV charging using whole-home smart meter load disaggregation (Figure 27). Through the program, BELD has tracked customer charging of over 12,000 EV charging days and verified over 95% off-peak charging compliance.

EV owners who agree to program their vehicles to charge during off-peak hours are given a bill credit as an incentive. If on-peak charging is identified from the AMI meter data, customers were reminded they could lose the incentive for the month. This daily tracking and accountability drove significantly higher rates of successful off-peak charging than do TOU rates, which achieve 70% to 80% of EV charging during off-peak hours, based on Sagewell's AMI meter tracking data.

BELD found that eliminating load-control hardware caused a higher percentage of EV owners in its service territory to enroll in the program. The average customer enrollment time is only 7 minutes via smartphone. Sagewell provides support and program oversight to help customers as they begin enrollment. BELD also found that enrolling customers early in their EV ownership led to maximum enrollment as enrollment rates decreased the longer a customer owned an EV. BELD has used Sagewell's EVFinder algorithm daily to find new EVs in utility smart meter data and to direct EV program marketing messages that included BYOC information to those customers who recently acquired an EV.

BELD's analysis of smart meter data also highlighted that utilities should carefully analyze their TOU rates because many may be discounting their regular residential rates too much and giving up more in margins than the peak load reduction justifies. The BYOC program produced significantly higher program participation and larger peak load reduction at a lower cost than TOU rates. Sagewell encourages utilities to carefully analyze their EV load management options and to use their AMI data to find the peak load reduction potential for customers rather than using modeled results or data from other utilities. For example, differences in weather, miles driven and utility coincident peak times between different regions make it challenging to compare results between different EV load management programs and highlights the importance of using local AMI meter data for the analysis.

7) Conclusion

Time-varying rates are a valuable tool for utilities to manage system costs by influencing residential EV charging behavior. Specifically, the quantitative analysis described in this study shows that EV time-varying rates effectively incentivize off-peak charging, and that customers are interested in using them. Enticing the maximum number of EV customers to enroll in these rates is essential to ensuring that EV charging load is managed effectively. Designing rates that encourage off-peak charging, save customers money, require limited up-front fees, and that are easily available to EV customers leads to the highest customer enrollments.

This section includes recommendations for utilities as they consider options for EV time-varying rates, and provides next steps for other research topics, as we continue to refine our knowledge about load management strategies.

A. Recommendations

Utilities can take advantage of early opportunities to improve EV-grid integration through time-varying rates. Recommendations compiled from the survey results and utility interviews include:

1. Minimize the up-front costs for customer enrollment wherever possible. Utility costs may include metering equipment (and in some cases EVSE), installation, and in-house utility overhead such as IT setup, marketing, etc. Determining which costs the customer bears, the manner in which they are collected (e.g., bundled monthly charge versus a prepayment option), as well as the recovery mechanisms for costs not recovered directly from participants are critical considerations for utilities and regulators.
2. Make the price differential between 'on-peak' and 'off-peak' significantly large to incentivize participation, but not so large that it deters customers from enrolling. Offering multiple rate options with different designs allows utilities to appeal to and engage more customer types and preferences.
3. Where possible, incorporate an "opt out" rather than passive "opt in" elective—especially for programs containing a rebate or incentive for a charger or vehicle purchase.
4. Make the time-varying rate options for consumers meaningful, with substantive differences in the rate structures rather than offering customers several rates that have only slight variations. Provide tools and information to help customers make a rate choice that works best for them.
5. Consider innovative approaches to rates and incentives, such as dynamic rates, off-peak credits, subscription rates, and load disaggregation with retroactive incentives.
6. Ensure adequate marketing funding to promote the rate to customers. Use multiple marketing channels to amplify the message. Target rate marketing among known or likely EV drivers.
7. Build a long-term strategy to transition from passive managed charging to active managed charging, considering the time it may take to introduce and get regulatory approval for new rates and programs.
8. Work with EVSE providers to deliver unified open standards that could lower the cost of integrating networked EV charger telemetry.

B. Future Research

While this report provides valuable new insight into EV time-varying rates, a number of questions remain. These include elements of rate design, evaluation, measurement, and verification (EM&V) of rate effectiveness, lower-cost alternatives to collecting charging data, how to measure the key performance indicators (KPI) of marketing efforts, the appropriateness of ratebasing program costs, and more, as outlined below.

Active Load Management

- What is the time horizon for active load management offered by utilities and private vendors? What is the value of active load management and what are the use cases?

Rate Design

- Which customer segments prefer a separately metered EV-only rate to a whole-home rate? What portion of the customer base—enough to justify utilities offering customers both options?
- How can utilities design rates to promote efficient utilization of lower-cost and clean generation resources?
- Will customers shift load to the off-peak period if it occurs in the middle of the day (e.g., when there is excess solar PV output)?
- Do customers respond differently to peak/off-peak pricing than to rate discounts, monthly incentives, or bonuses for charging at night?

- Nearly all of the EV Time-Varying Rates reviewed in this report are TOU programs. Should utilities explore other time-varying rate options for EV charging and would some residential EV customers be better off under one of these alternatives versus a TOU rate?
- Should time-varying rates be required for participants in ratepayer-funded EV home charging programs to ensure that all customers benefit from large-scale shifts in EV charging load to off-peak periods?

Rate Performance

- Is time-varying EV pricing effective at encouraging EV adoption, or is it primarily for encouraging off-peak charging once the EV has been purchased?
- How will these rates impact charging behavior—especially among later adopters of EV technology?
- How will utilities evaluate, measure, and verify the effectiveness of EV rates—particularly utilities transitioning from a pilot to a rate of general application?
- How do you measure the KPI of marketing expenditures to increase the number of consumers on a rate and/or who purchase an EV as a result of the rate?

Cost Recovery

- Should secondary or submetering costs be recovered from participants (which could be a significant deterrent to participating) or will the rate lead to off-peak charging and benefit all customers, thereby justifying recovery of the meter cost from a broader group of customers? Should costs be recovered differently for "early adopters" versus "late adopters" of EV technology? How should the costs associated with EV rate and program marketing, IT set up costs, and other overhead be recovered?

Technology Considerations

- Will additional incentives encourage higher enrollment and more off-peak charging?
- Can customers enrolled in one demand management program, such as EV charging, be motivated to join other programs, such as smart thermostats or grid-integrated water heating?
- How can new tools help increase enrollment, such as showing customers their average charging patterns in monthly bills, compared to a different charging pattern or a different rate?

Appendix A: List of Available Residential EV Time-Varying Rates

The list of available residential EV time-varying rates was compiled using research from SEPA The Brattle Group, OpenEI, and other online resources. This list was updated through September 2019 and includes 64 rates from 50 utilities that were open for enrollment at the time they were collected. This list does not include expired or grandfathered rates.

Table 8: Available Residential EV Time-Varying Rates, September 2019

	Utility Name	Rate Name	Rate Type
1	Alabama Power Company	PEV Rate Rider	Time-of-Use
2	Alaska Electric Light and Power Co.	Off-Peak Electric Vehicle Charging	Time-of-Use
3	ALLETE (Minnesota Power)	EV TOU Rate	Time-of-Use
4	Anaheim Public Utilities	Developmental Schedule D-EV Rate (Developmental Domestic Electric Vehicles)	Time-of-Use
5	Austin Energy	EV360	Subscription
6	Baltimore Gas and Electric	Schedule EV	Time-of-Use
7	Belmont Light	Bring Your Own Charger	Off-Peak Credit
8	Berkeley Electric Coop Inc.	Off-Peak EV Rate	Time-of-Use
9	Braintree Electric Light Department	Bring Your Own Charger Program	Off-Peak Credit
10	City of Burbank Water and Power	Optional Time-of-Use Rates for Electric Vehicle Owners	Time-of-Use
11	Coastal EMC	TOU-PEV-1	Time-of-Use
12	CobbEMC	NiteFlex	Time-of-Use
13	Concord Municipal Light Plant	Rate R-1	Time-of-Use
14	Concord Municipal Light Plant	EV Miles Program	Off-Peak Credit
15	Consolidated Edison Company	Special Provision E of SC1 Rate III	Time-of-Use
16	Consolidated Edison Company	Special Provision F of SC1 Rate III	Time-of-Use
17	Consumers Energy Co.	REV-1	Time-of-Use
18	Consumers Energy Co.	REV-2	Time-of-Use
19	Dakota Electric Cooperative	Schedule EV-1 Pilot—Residential Electric Vehicle Service	Time-of-Use

Table 8: Available Residential EV Time-Varying Rates, September 2019			
	Utility Name	**Rate Name**	**Rate Type**
20	Delmarva Power & Light	R-PIV	Time-of-Use
21	DTE	D1.9 EV Time-of-Use	Time-of-Use
22	Evergy	Residential Electric Vehicle Rate	Time-of-Use
23	Georgia Power Company	Schedule TOU-PEV-6—Plug-in Electric Vehicle	Time-of-Use
24	Gulf Power Co.	Rate Schedule RSVP Residential Service Variable Pricing	Time-of-Use
25	Hawaii Electric Light Company	Schedule TOU-RI	Time-of-Use
26	Hawaiian Electric Company	Schedule TOU-RI	Time-of-Use
27	Indiana Michigan Power Company	Tariff RS-PEV	Time-of-Use
28	Indianapolis Power & Light Company	IPL Response: Rate EVX	Time-of-Use
29	Jackson EMC	Residential Plug-in Electric Vehicle Rate (APEV-19)	Time-of-Use
30	Los Angeles Department of Water and Power	EV TOU	Time-of-Use
31	Madison Gas & Electric	Shift & Save	Time-of-Use
32	Maui Electric Company	TOU EV	Time-of-Use
33	New Hampshire Electric Cooperative	EV Time-of-Use Rate	Time-of-Use
34	Norwood Light Department	Bring Your Own Charger Program	Off-Peak Credit
35	NV Energy	OD-REVRR-TOU	Time-of-Use
36	NV Energy	ODM-1-TOU REVRR	Time-of-Use
37	NV Energy	ORS-TOU REVRR	Time-of-Use
38	NV Energy	ORM-TOU RMEVRR	Time-of-Use
39	Orange and Rockland Utilities	O&R SC19	Time-of-Use
40	Otter Tail Power Company	Off-Peak EV	Time-of-Use
41	Pacific Gas & Electric	EV-2A; Electric Schedule EV—Rate A	Time-of-Use
42	Pacific Gas & Electric	EV-B; Electric Schedule EV—Rate B	Time-of-Use
43	Pacific Power (PacifiCorp)	Schedule 5—Separately Metered Electric Vehicle Service For Residential Consumer	Time-of-Use
44	Pepco Holdings, Inc.	Whole House EV TOU	Time-of-Use

Table 8: Available Residential EV Time-Varying Rates, September 2019			
	Utility Name	**Rate Name**	**Rate Type**
45	Piedmont Electric Membership Corporation	Schedule R/SGS-TOD-E-PEV	Time-of-Use
46	Rocky Mountain Power (PacifiCorp)	Schedule 2E—Residential Service—Electric Vehicle Time-of-Use Option—Temporary—Rate Option 1	Time-of-Use
47	Rocky Mountain Power (PacifiCorp)	Schedule 2E—Residential Service—Electric Vehicle Time-of-Use Option—Temporary—Rate Option 2	Time-of-Use
48	Sacramento Municipal Utility District	Schedule R-TOD, rate category RT01	Time-of-Use
49	Salt River Project	E-29 Residential Electric Vehicle Price Plan	Time-of-Use
50	San Diego Gas & Electric	EV TOU 2	Time-of-Use
51	San Diego Gas & Electric	EV TOU 5	Time-of-Use
52	San Diego Gas & Electric	EV TOU	Time-of-Use
53	San Francisco Public Utilities Commission	Schedule REV-1	Time-of-Use
54	Sawnee EMC	Schedule PEV-7	Time-of-Use
55	Southern California Edison Co.	TOU-D-PRIME	Time-of-Use
56	Virginia Electric & Power Co.	Schedule EV	Time-of-Use
57	Virginia Electric & Power Co.	Schedule 1EV	Time-of-Use
58	Wake Electric Membership Corporation	EV Rate	Time-of-Use
59	Wake Electric Membership Corporation	EV TOU	Time-of-Use
60	Wellesley Municipal Light Plant	Bring Your Own Charger Program	Off-Peak Credit
61	Wright-Hennepin Cooperative Electric Association	EV TOU Rate	Time-of-Use
62	Xcel Energy MN	Residential Electric Vehicle Pilot Service Rate Code A80	Time-of-Use
63	Xcel Energy MN	Residential Electric Vehicle Pilot Service Rate Code A81	Time-of-Use
64	Xcel Energy MN	Residential Electric Vehicle Service Rate Code A08	Time-of-Use

Source: Smart Electric Power Alliance, 2019. Updated through September 30, 2019.

Appendix B: Recommended Reading

- Baltimore Gas & Electric, 2018, *BGE Electric Vehicle Off Peak Charging Pilot*, Docket 9261: In The Matter of the Investigation Into the Regulatory Treatment of Providers of Electric Vehicle Charging Stations and Related Services.
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    - https://drive.google.com/file/d/1hpIClxrFYwLxulg1tXW2jAPhxbMnloMQ/view

Appendix C: Time-Varying Rate Definitions

For the purposes of this report, time-varying rates are grouped into seven categories: Time-of-Use (TOU), Subscription Rates, Off-Peak Credits, Real Time Pricing (RTP), Variable Peak Pricing (VPP), Critical Peak Pricing (CPP), and Critical Peak Rebates (CPR).[48]

These rates are illustrated in Figure 28.[49]

- **Time-of-Use (TOU)** rates typically have two or more price intervals (e.g., peak, off-peak, super-off-peak) that differ based on levels of demand observed throughout the day. Sometimes these prices vary by season, but generally speaking both the prices and the designated price interval hours for each tier remain constant from day to day.
- **Subscription Rates** allow customers to pay a fixed monthly fee for electricity and other utility-provided services in exchange for unlimited charging during certain hours of the day or days of the week. Customers would subscribe to a plan which meets their specific needs, varying from "economy" packages which give the utility some ability to control their load at restricted and pre-published times to help meet grid needs, to high-priced packages with long-term subscriptions and access to new technologies without upfront costs.
- **Off-Peak Credits** can take the form of a fixed or variable incentive provided as a rebate or a bill credit in exchange for restricting consumption to designated hours of the day or days of the week.

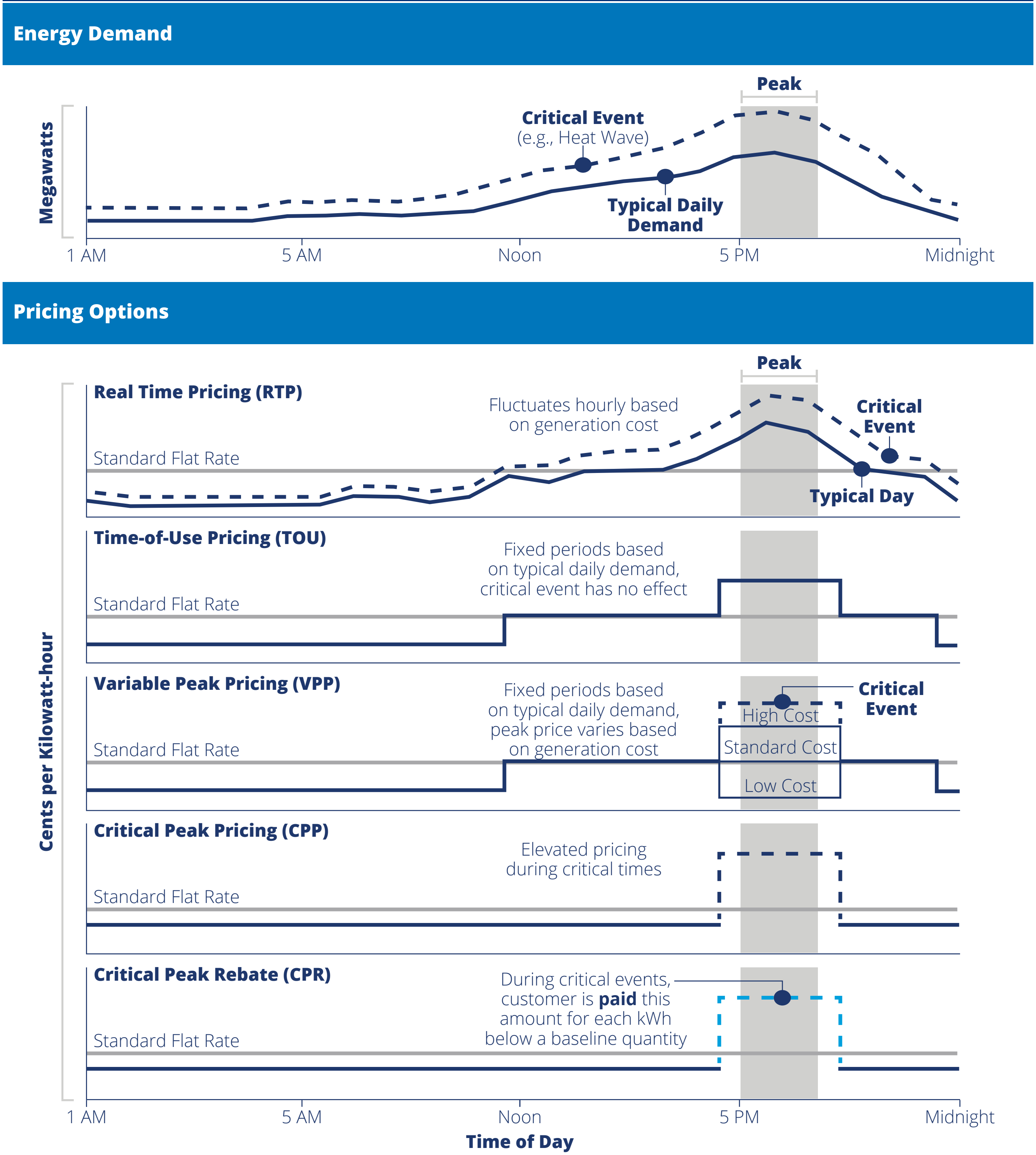
Dynamic Rates (time periods and prices vary based on system conditions and power cost):

- **Real Time Pricing (RTP)** is the most complex time-varying rate. Variable, hourly prices are determined either by day-ahead market prices in order to allow the customer to be notified with time to alter consumption decisions, or real-time spot market prices.
- **Variable Peak Pricing (VPP)** is a hybrid of TOU and RTP, with price intervals (e.g., peak, off-peak) that are constant like a TOU rate but allow for the price charged during the peak tier to differ day to day. The peak price charged varies from day to day either based on market prices or a set of predetermined levels, to reflect system conditions and costs.
- **Critical Peak Pricing (CPP)** has a higher rate at designated peak demand events (also called "critical events") on a limited number of days during the year to reflect the higher system costs during these hours. The customer can avoid paying high prices by reducing electricity use during these periods of high demand (which may only occur up to a predetermined number of times per year) and benefit from a lower price for non-event hours relative to the flat rate.This pricing provides a strong incentive for customers to reduce consumption during peak hours of critical event days, but provides no incentive to reduce use on non-event days or hours.
- **Critical Peak Rebate (CPR)**, also called Peak Time Rebate (PTR), is the inverse of CPP. Utilities pay customers a rebate for each kWh of electricity they reduce during peak hours of peak demand events. Similar to CPP, this pricing incentivizes a reduction in use during even days, but does not provide an incentive for customers to reduce use on non-event days or hours.

48 Definitions adapted from: Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf . Subscription Rates and Off-Peak Credits are not discussed in the EDF primer.

49 Ibid.

Figure 28: Time-Varying Rate Options



Source: Environmental Defense Fund, 2015 with edits by the Smart Electric Power Alliance.[50]

50 Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf

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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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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.

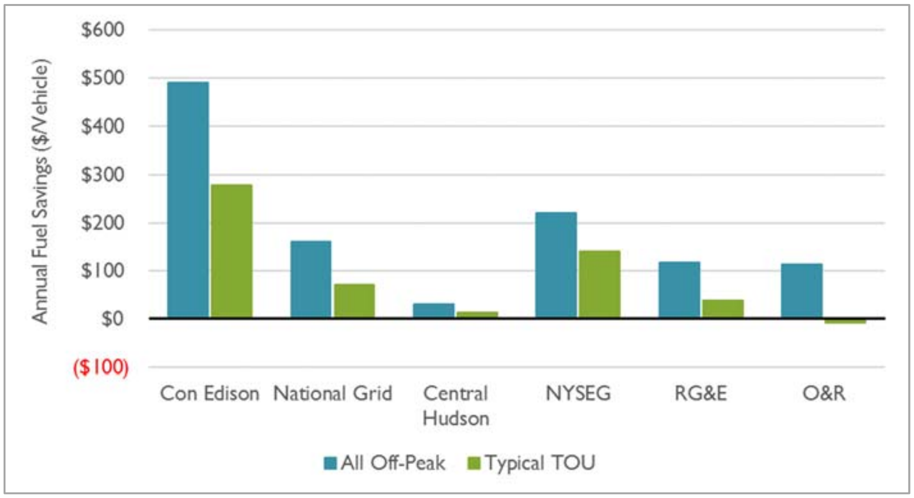
- **Metering:** None of the New York IOUs have proposed a submetering option using an EVSE for their EV rates, nor have they explained why submetering was not proposed. Instead, the IOUs that offer an EV-only rate would require a second traditional utility meter, with the exception of Consolidated Edison 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

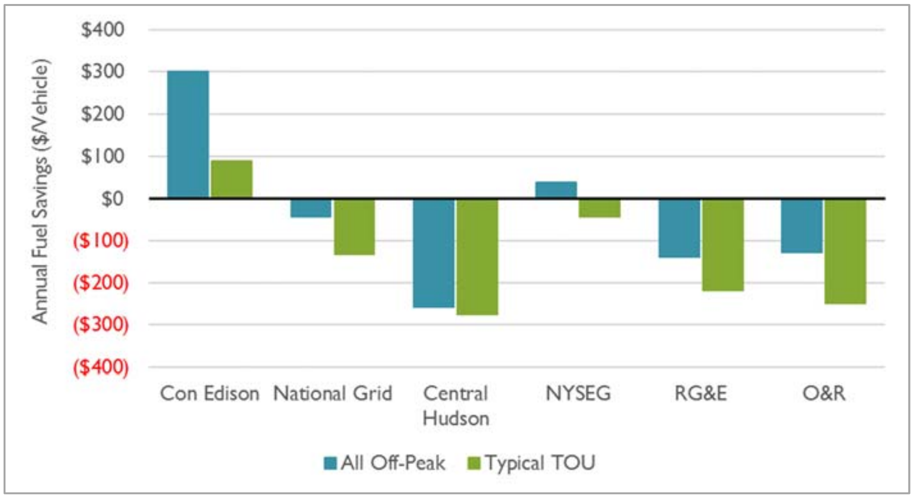


Source: Synapse Energy Economics analysis.

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.

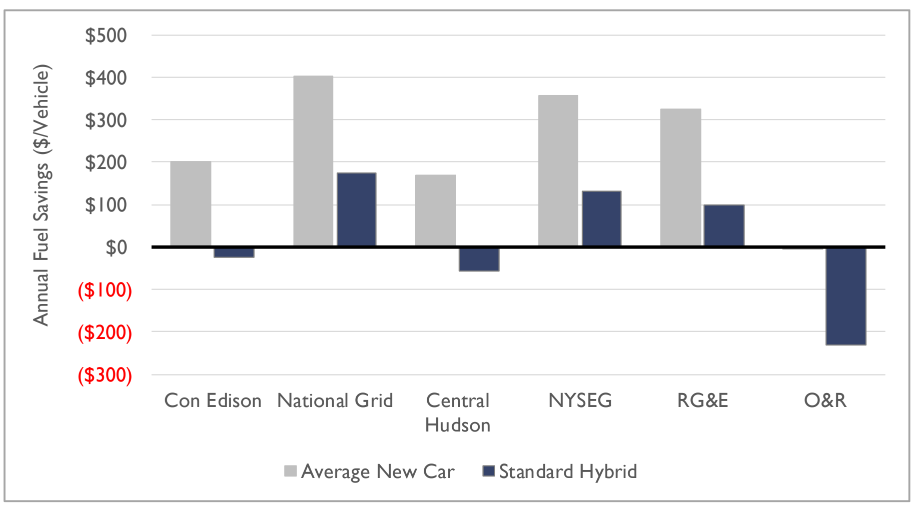
Figure ES-2. EV-only TOU rate annual fuel cost savings relative to standard rate



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.

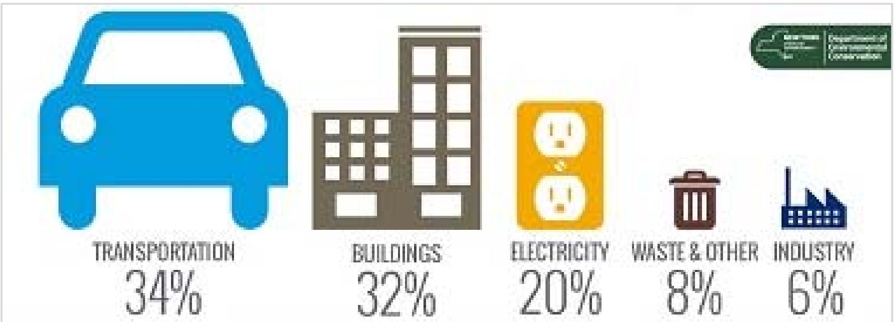
[7] We use the term "electric vehicles" to refer to both plug-in hybrid electric vehicles and battery electric vehicles.

[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]

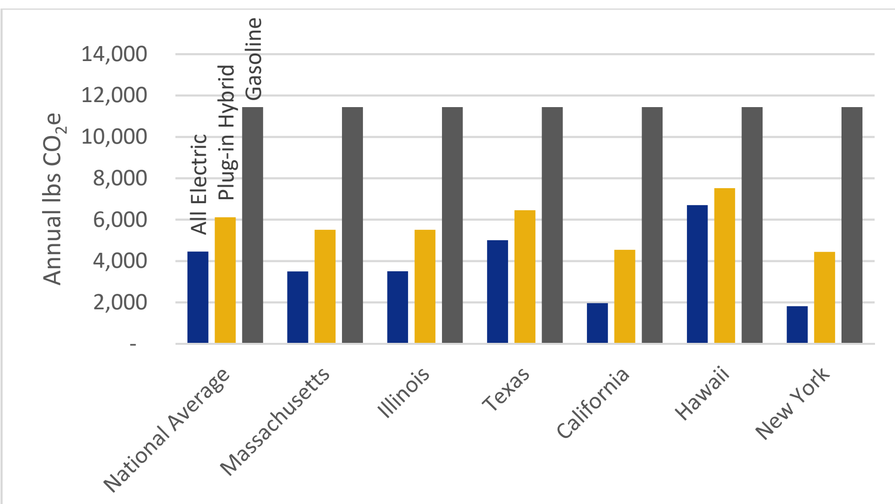
Figure 1. Greenhouse gas emissions by sector in New York



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.

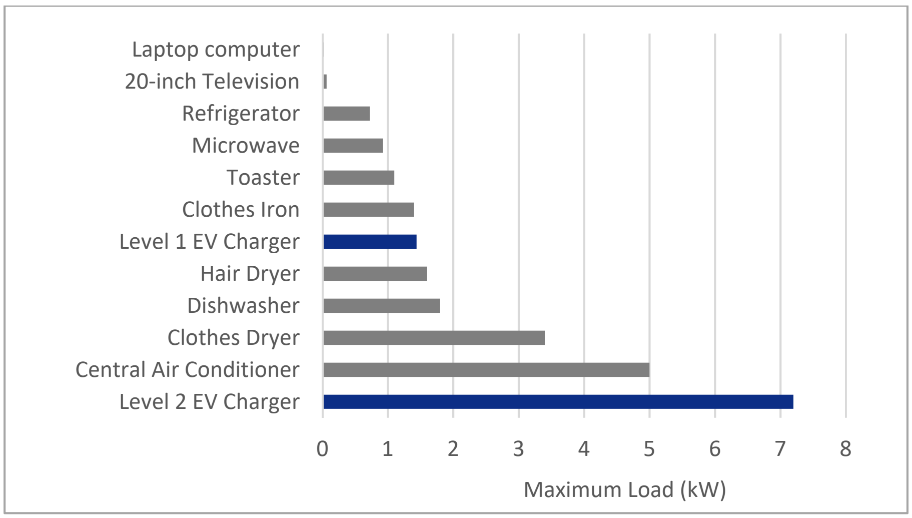
[12] U.S. Department of Energy Alternative Fuels Data Center. 2015. "Emissions from Hybrid and Plug-In Electric Vehicles." Available at: www.afdc.energy.gov/vehicles/electric_emissions.php.

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.

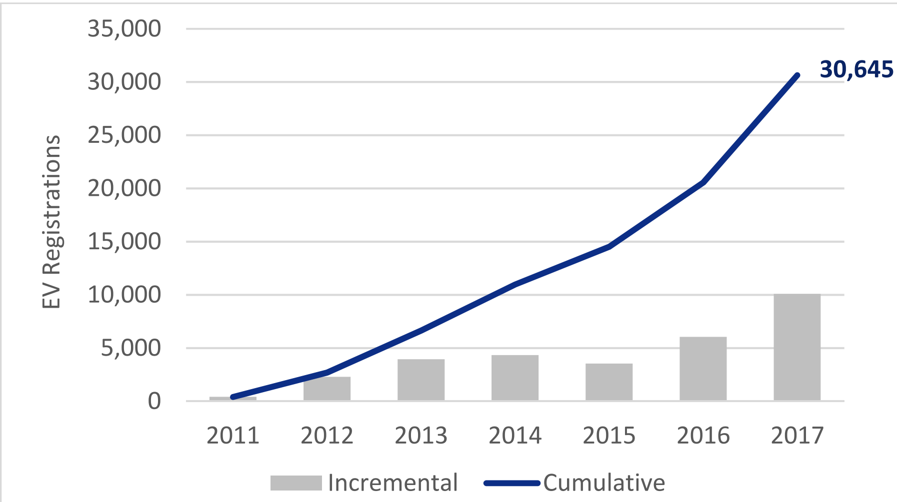
owners of public EV charging stations, thereby reducing demand for EVs and slowing the transition to the cleaner transportation system necessary to meet state goals.

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

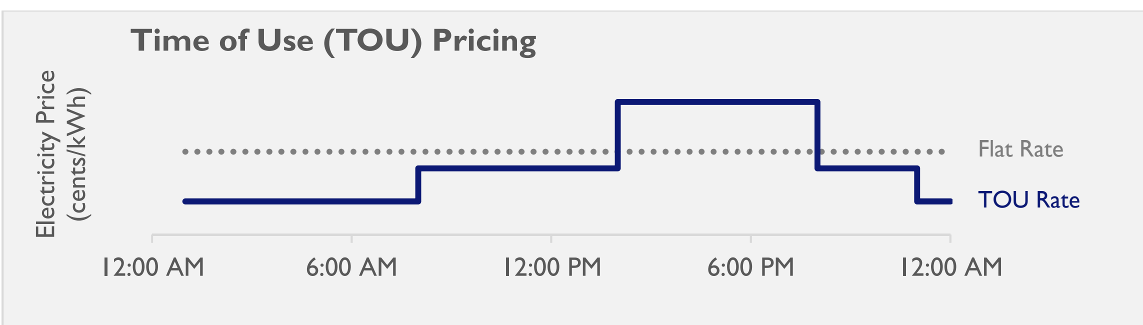
4) Reduce emissions by better aligning charging with renewable energy production.

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.

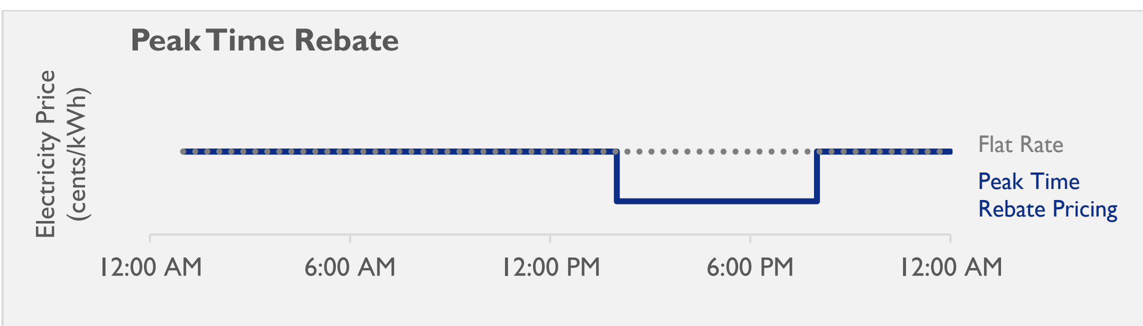


- *Critical Peak Pricing (CPP):* This rate structure is often used in conjunction with TOU rates but can be used with an otherwise flat rate structure as well. Critical peak pricing implements a very high price tier that is only triggered for very specific events, such as system reliability or peak electricity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

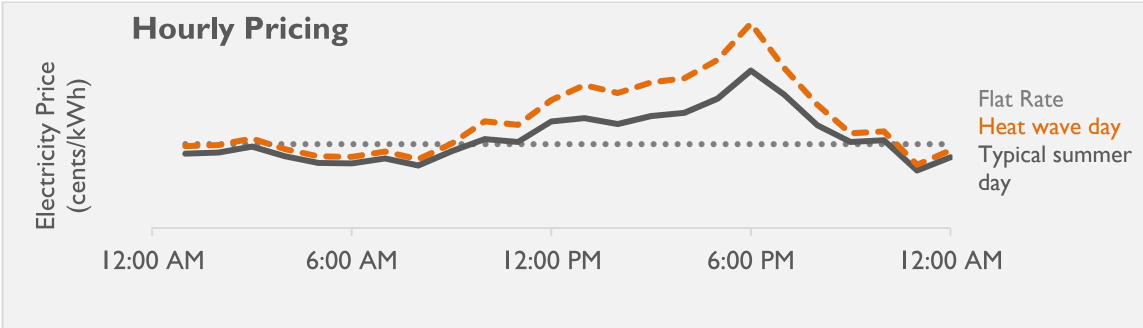


- *Real-Time Pricing and Hourly Pricing:* These rates charge customers for electricity based on the wholesale market price rather than a pre-set rate schedule.[19] Rates fluctuate hourly or in 15-minute increments, reflecting changes in the wholesale price of

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

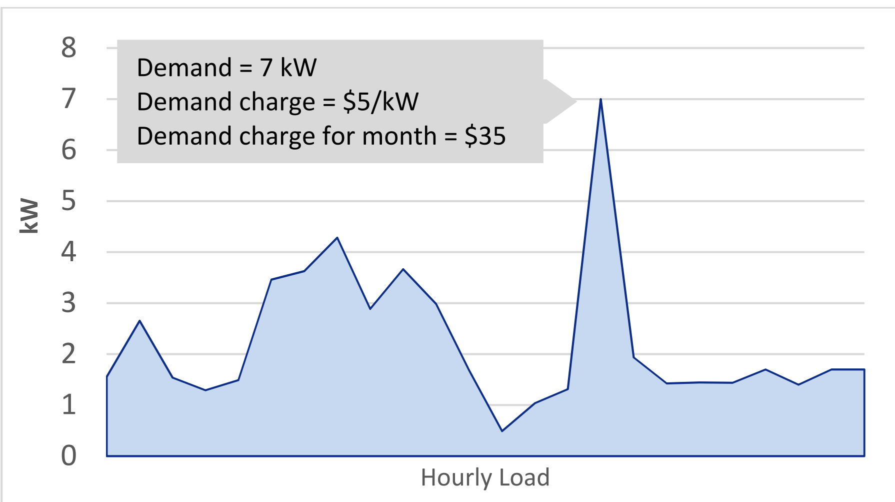
[19] *Id*.

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

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[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

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[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

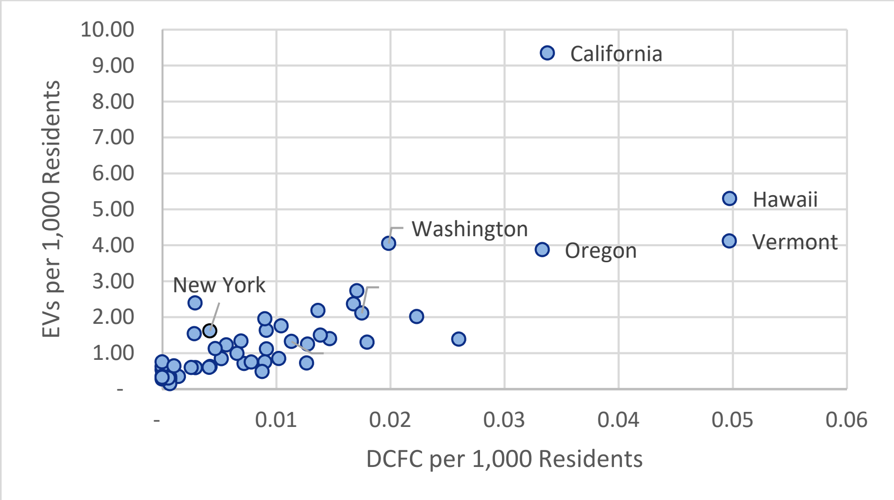
		High Case	Mid Case
Demand Charge ($/kW)		$20	$6
Customer Charge (4/Month)		$70	$70
Energy Charge ($/kWh)		$0.08	$0.08
Energy per Session (kWh)		50	50
15 charging sessions/month	Annual DCFC Bill	$25,560	$8,760
	Cost/session	$142	$49
	Cost/kWh	$2.84	$0.97
60 charging sessions/month	Annual DCFC Bill	$27,720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

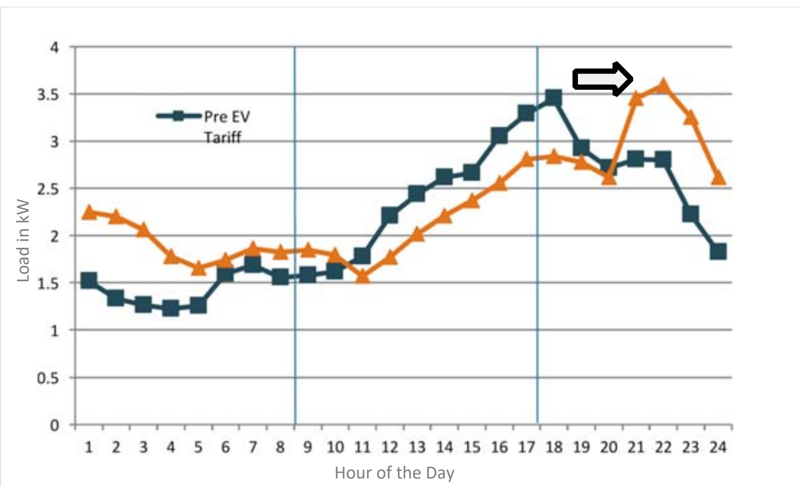
3. IMPLEMENTATION OF EV RATES: LESSONS FROM THE FIELD

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.

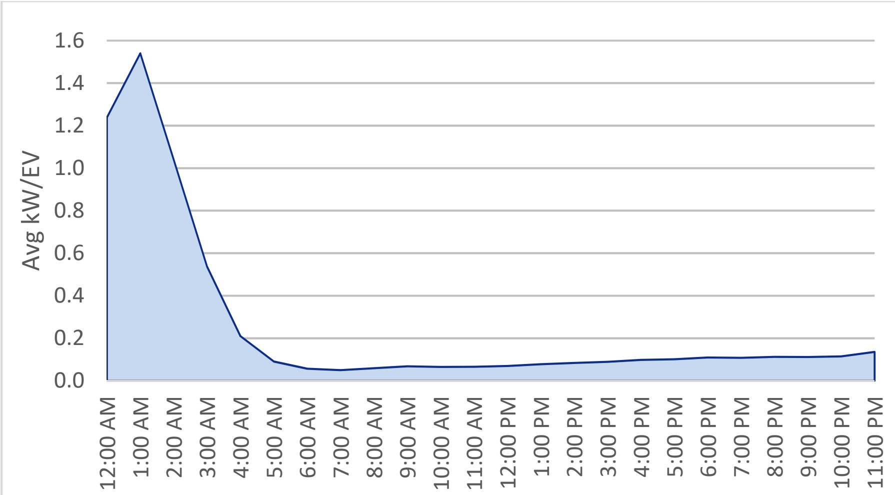
Figure 7. Results of BGE EV tariff pilot



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

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[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]

[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

Technical Challenges and Progress

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

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[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,

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.

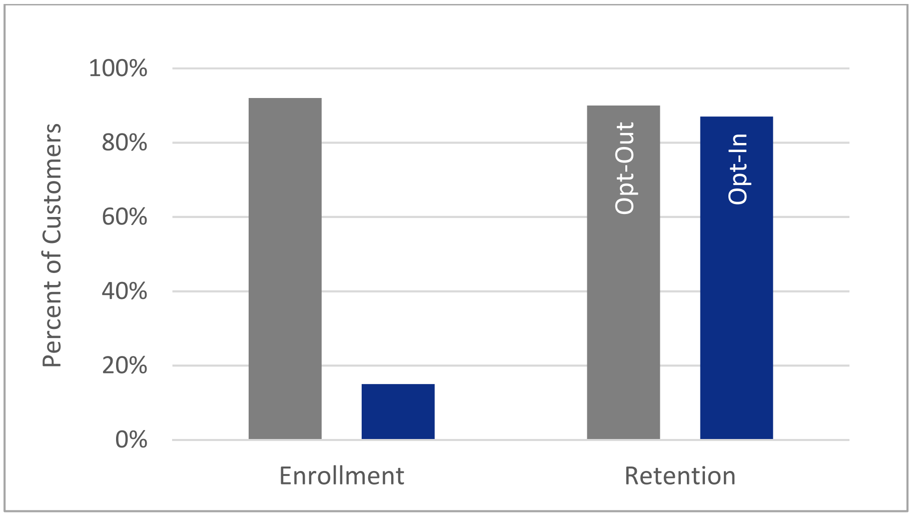
[66] California's submetering pilot program documents are available at http://www.cpuc.ca.gov/general.aspx?id=5938.

[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.

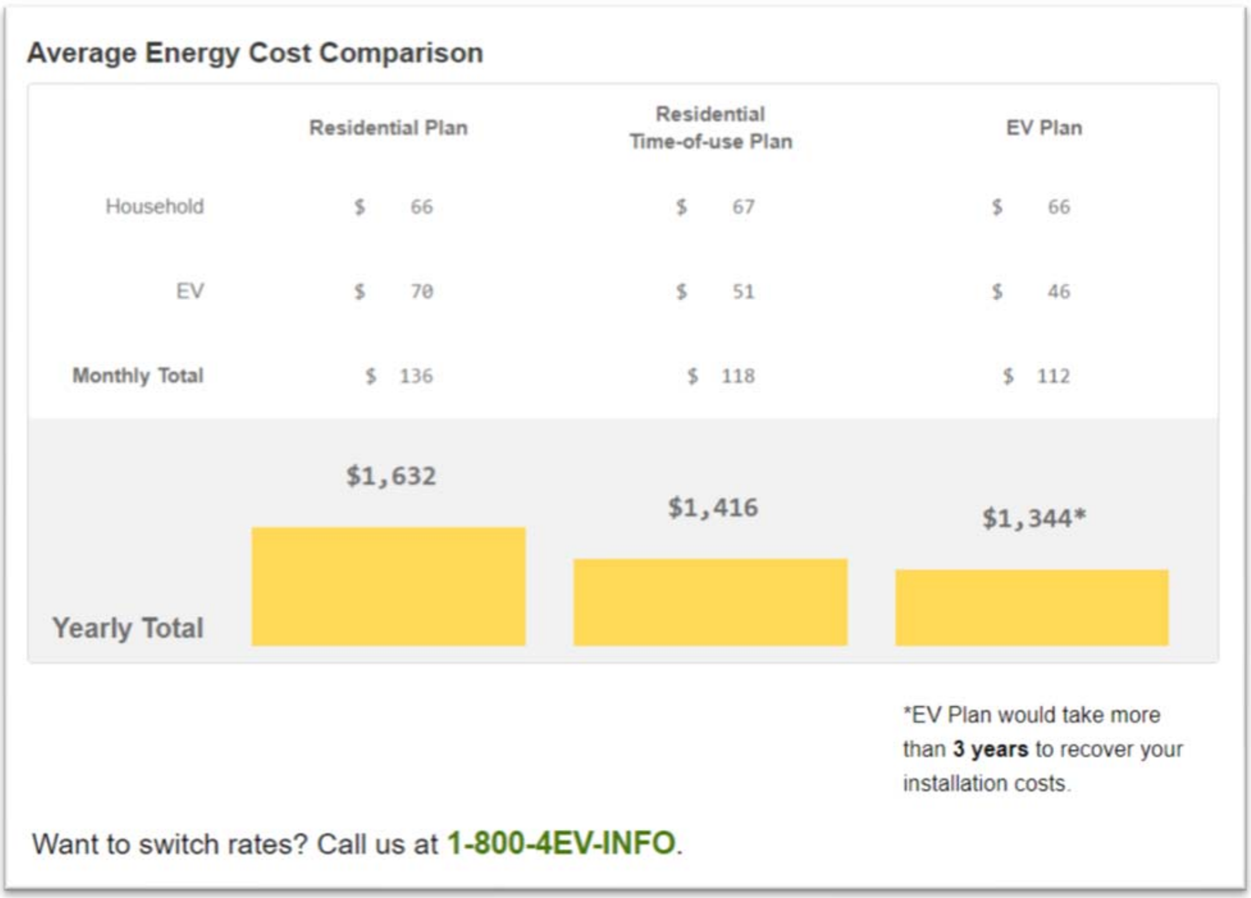
Activities to maximize EV customer enrollment in EV rates may include:

[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.

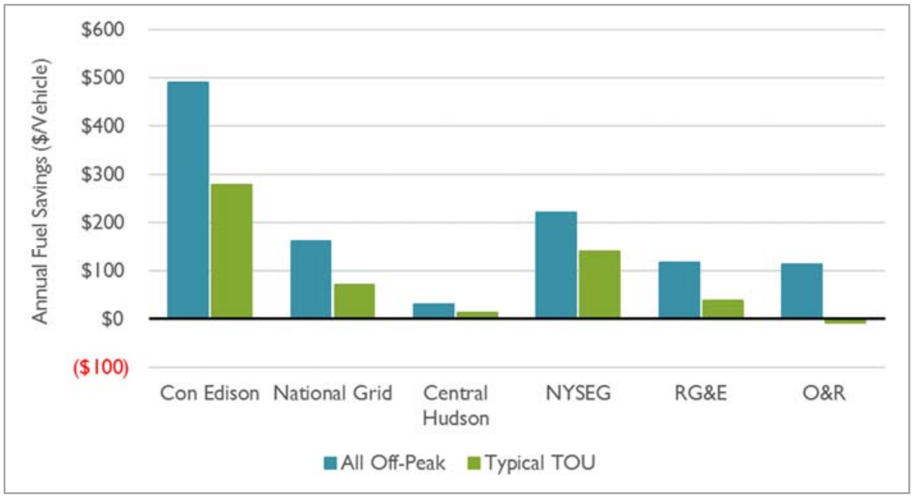
[81] AAA Foundation for Traffic Safety, American Driving Survey 2015-2016. https://aaafoundation.org/wp-content/uploads/2018/02/18-0019_AAAFTS-ADS-Research-Brief.pdf; AAA Foundation for Traffic Safety, American Driving Survey 2013-2014. https://newsroom.aaa.com/wp-content/uploads/2015/04/REPORT_American_Driving_Survey_Methodology_and_year_1_results_May_2013_to_May_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.

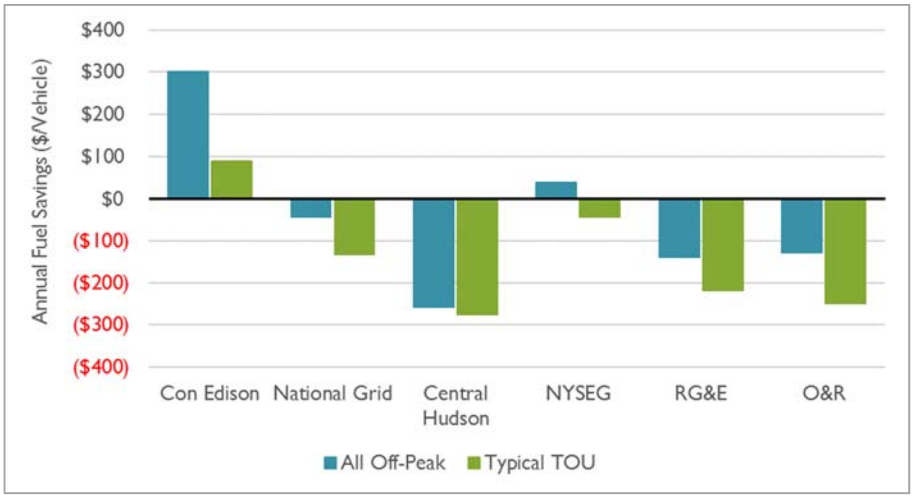
Under the scenario in which most, but not all, charging occurs during the off-peak period, the fuel cost savings are reduced substantially. A typical 100-mile BEV customer would be expected to save an average of approximately $250 per year at Con Edison. In contrast, we would expect that a typical O&R 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]

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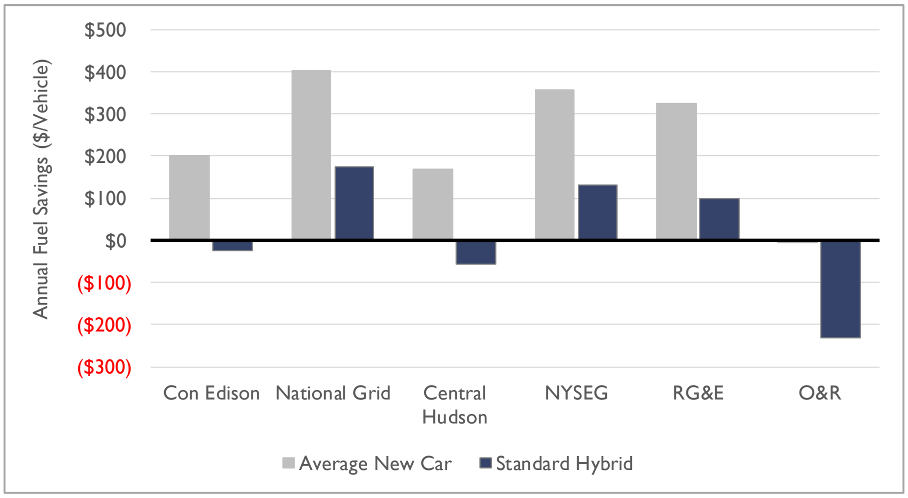
84 Although National Grid and Central Hudson did not specifically propose to allow EV customers to separately meter their EV loads, for the purposes of a comparative analysis we assumed that this would be allowed. The changes in fuel cost savings from Figure 15 to Figure 16 for National Grid and Central 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.

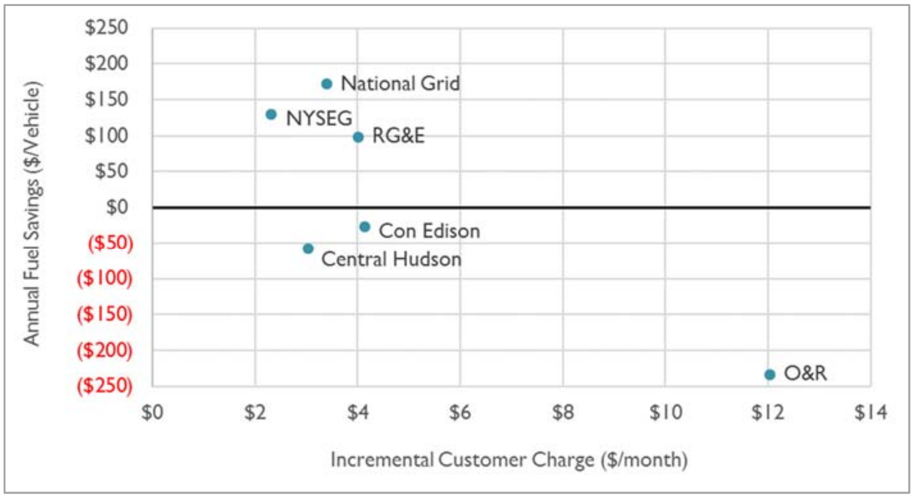
When compared to a standard hybrid vehicle, such as a Toyota Prius, EV fuel savings largely disappear. At three of the six IOUs, an EV customer would likely have higher fuel costs relative to a hybrid vehicle. This comparison is important, because customers considering purchasing an EV are likely to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

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[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

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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.

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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).

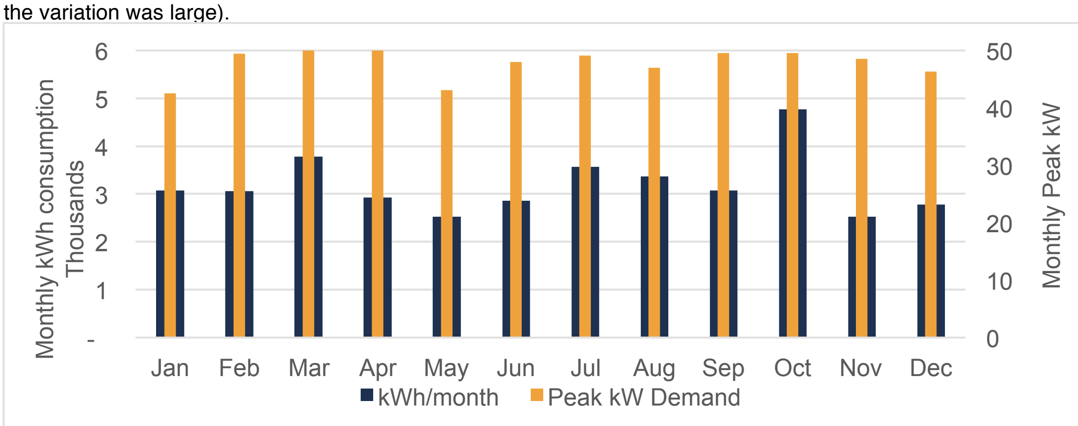

Figure 1: Monthly energy use and peak demand of an individual EVgo host site

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.

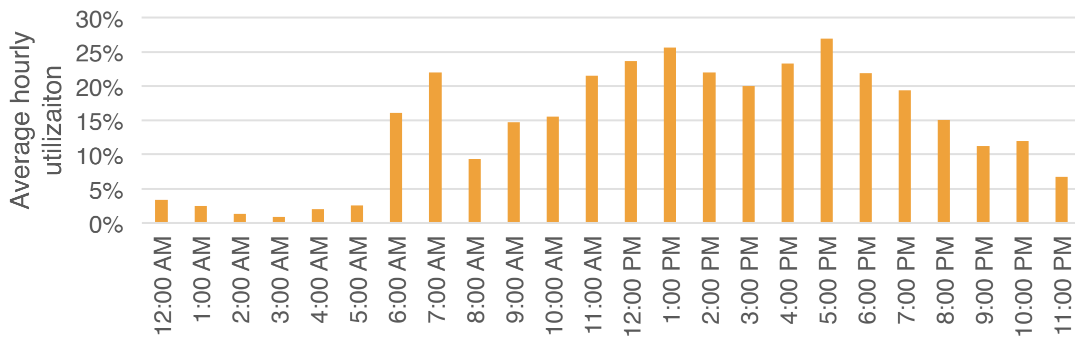

Figure 2: Hourly utilization rates of an individual EVgo host site

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.

[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.

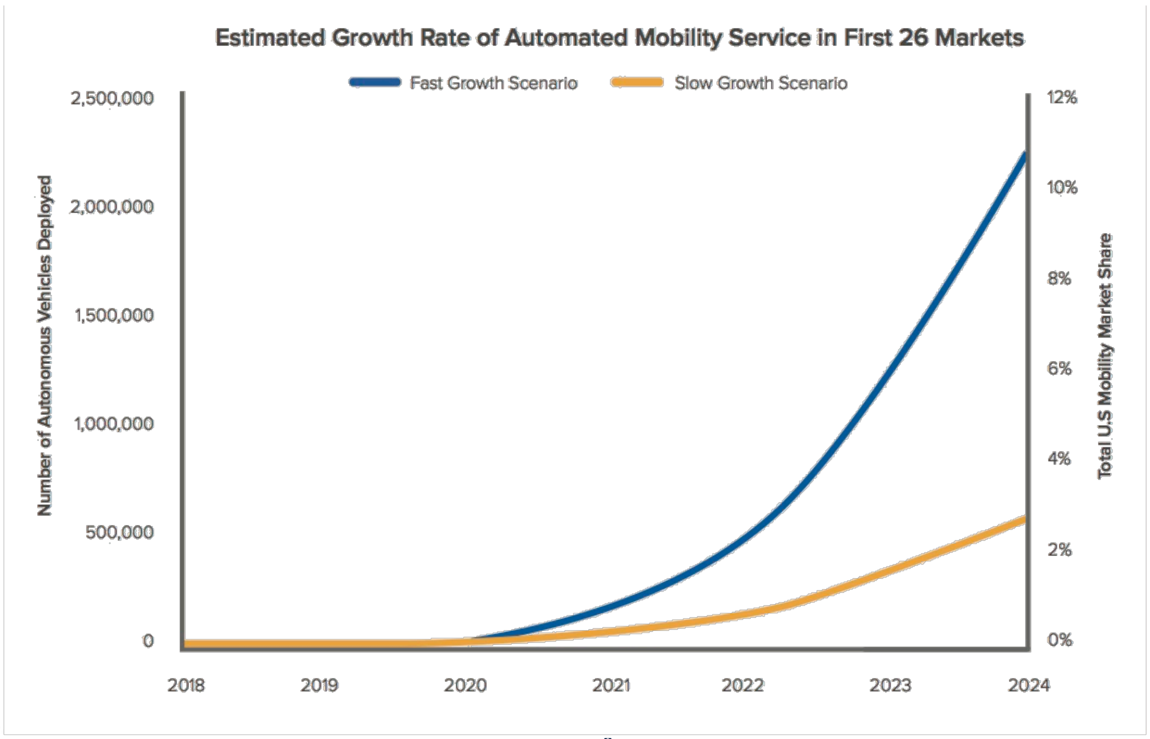

Figure 3 Mobility-as-a-service scenario. Source: RMI 2016, *Peak Car Ownership*[2]

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.

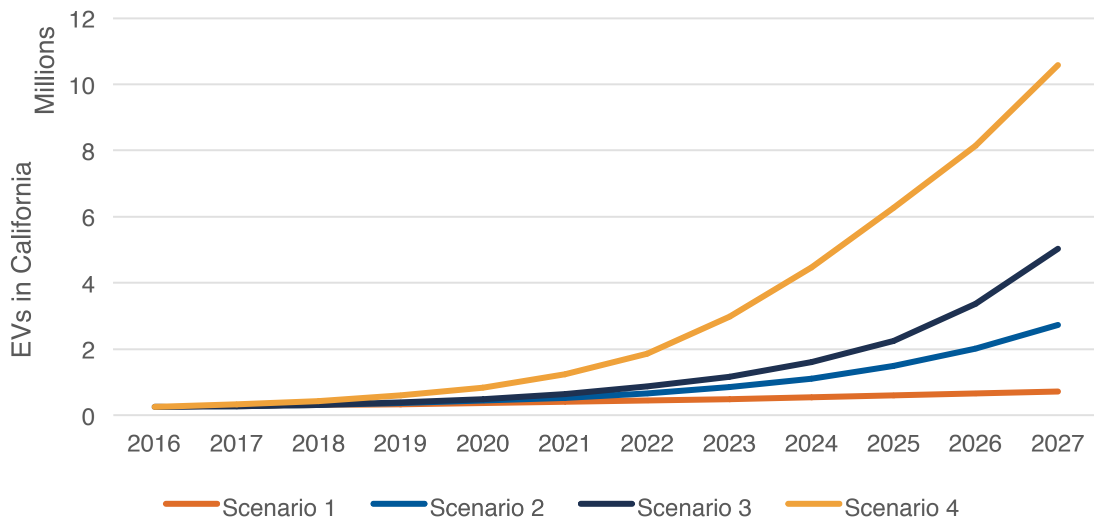

Figure 4: California EV deployment in the scenarios

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.)

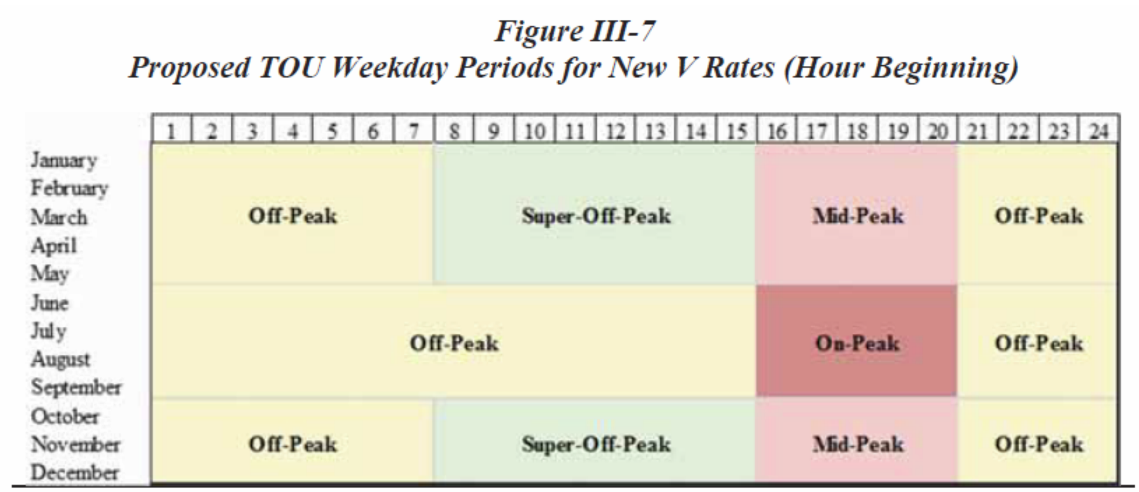

Figure 5: SCE's proposed ToU schedule for new EV tariffs. Source: Southern California Edison[14]

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.

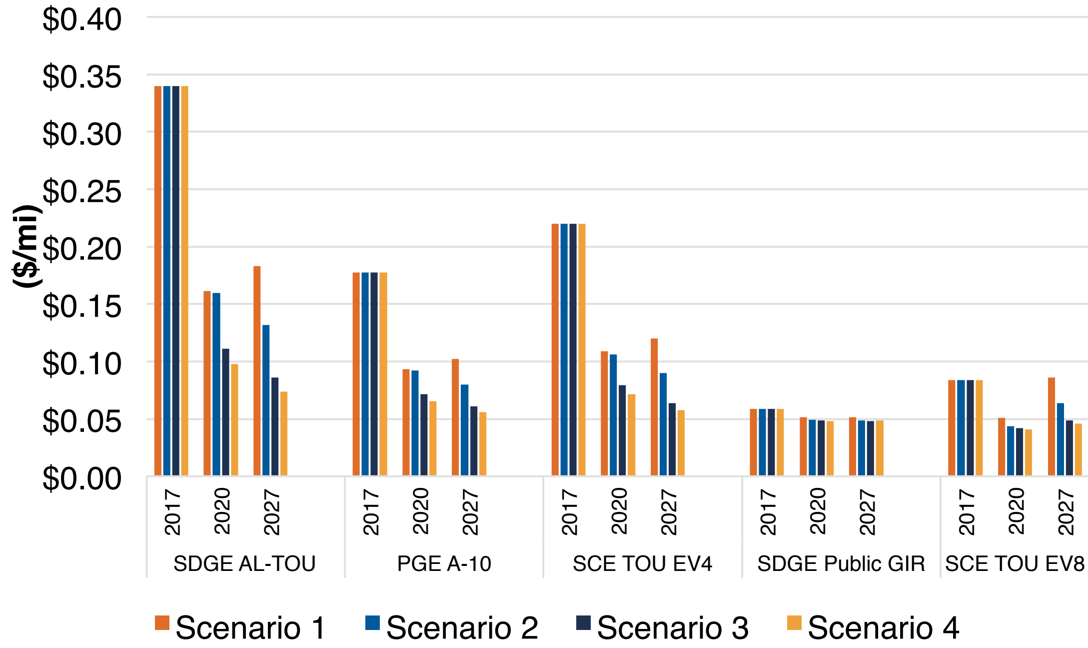

Figure 6: EVgo's cost per mile to deliver one mile of EV charge for existing and proposed EV tariffs

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

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[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

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

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.

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.

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.

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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.

<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.

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.

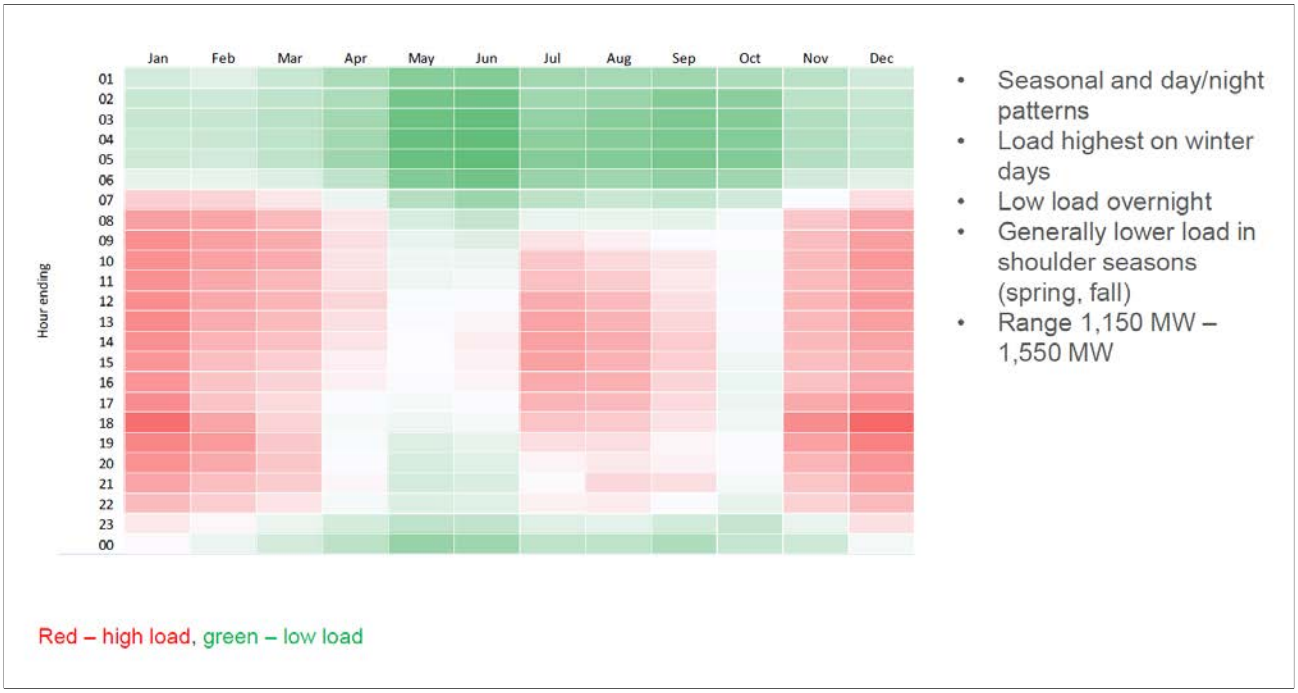

Figure 1: Gross Load Heat Map

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

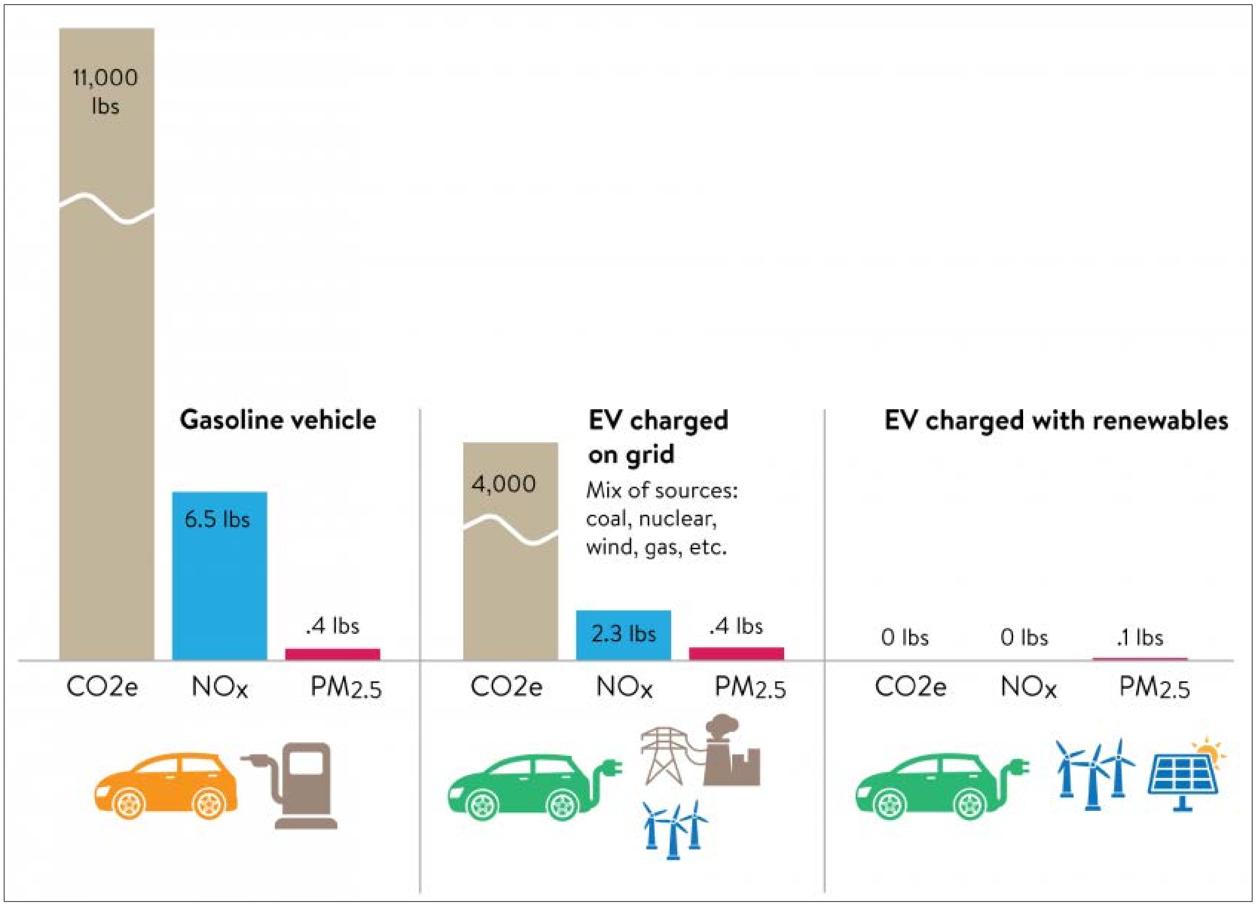

Figure 2: Annual emissions from electric vehicles and gasoline vehicles in Minnesota (12,000 miles)

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

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[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,

J Warmuth

Jenna Warmuth
Senior Public Policy Advisor
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30 West Superior Street
Duluth, MN 55802
(218) 355-3448
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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)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
ELECTRONIC FILING

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
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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
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.

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¢

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.

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	)	AFFIDAVIT OF SERVICE VIA
	) ss	E-FILING AND
COUNTY OF ST. LOUIS	)	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.

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

Issued By Puget Sound Energy
By: Jon Piliaris **Title:** Director, Regulatory Affairs

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)

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

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

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

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

Issued By Puget Sound Energy
By: Jon Piliaris **Title:** Director, Regulatory Affairs

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)