



**RATE DESIGN FOR EV FAST CHARGING:  
DEMAND CHARGES**

**White Paper (Part 2 in a Series)**

**ALLIANCE FOR TRANSPORTATION  
ELECTRIFICATION**

**BY THE RATE DESIGN TASK FORCE**

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# Executive Summary

This paper, the second in a series by the Alliance for Transportation Electrification (ATE or the Alliance) on rate design for EVs, attempts to explain the delicate balance that public utility commissions (Commissions) must strike in approving rates based on cost causation principles while allowing for incentives that assist the market transformation for EVs. Specifically, this paper will discuss why demand charges are a necessary component of distribution charges. It will also discuss the specific barriers of high demand charges, which can stymie the deployment of new commercial fast-charging stations by electric vehicle station service providers (EVSPs). The problem typically occurs when station utilization may be low during the initial deployment of public commercial charging stations. Because in this scenario these EV charging sites have sharp levels in demand relative to overall low utilization levels, they can incur relatively high demand charges, which then must be spread over few units of use (kWH) resulting in what can be high costs per kWH unit of usage to the electric vehicle service provider. If the EVSP is unable to recoup those high costs or pass them on to EV drivers, the business model of commercial fast-charging stations becomes uneconomic. If not addressed, this would significantly slow down the deployment of much needed public EV charging stations, which could in turn negatively affect EV adoption levels.

In many cases, the problem is temporary as station utilization levels are expected to increase over time. As utilization increases, the effects of high demand charges are lessened and demand charges at a certain level of utilization become more economic than alternatives based on purely volumetric energy rates. On the other hand, there may be charging stations located in rural or underserved communities or other locations where utilization remains low and cannot be incentive programs. Therefore, public utility commissions (“Commissions”) may need to carefully weigh the costs and benefits of utility rate design or incentive proposals designed to facilitate deployment of commercial EV fast-charging stations. In considering demand charge alternatives, it is also important to point out that each Commission may have differences in the legal precedent and in the application of rate design principles, which may affect their views and willingness to adopt different rate designs.

While it involves some flexibility on the part of all the parties, ATE believes there are effective solutions to the demand charge issue. In many cases, as noted above, the need for alternatives, including tariffs or incentives, to reduce traditional demand charges is temporary - but not in all cases. The Alliance’s recommendations have been developed as a means to provide relief to EVSPs from high demand charges to facilitate deployment of fast charging stations - recognizing the public policy benefits that EV market development provides to citizens of the state.

Specifically, ATE believes that there are four categories of alternative solutions that should be considered for either temporary or more permanent demand charge relief, as needed in particular use cases and situations:

- 1. *Short-term Mitigation of Demand Charges:*** Either waive or apply a discount to demand charges for a defined period of time to support commercial EV fast charging station

deployment to address a market gap. Waiver or discounts on demand charges would be applied on a pre-established schedule, but we recommend that Commissions institute a mid-point review to determine the appropriate timing for continuing or removing the rate support. Another option is to reduce demand charges but increase energy rates to offset some of the utility revenue lost from reduced demand charges.

- 2. *Cost-Based Rates without Demand Charges:*** Some utilities already offer rates to commercial customers that specifically target low load factors and do not include demand charges. But most of the time, the rates are limited to customers without very high peak demand. So, these rates, might for example, be available to Level 2 chargers or the lowest power levels for DC fast chargers, but not for fast charging at higher power levels.
- 3. *Rates with Embedded Demand Charges:*** While demand charges have proven to be an effective means of allocating fixed costs that customers impose on the system, there are rates for some use cases that can reflect cost of service without direct assessment of demand charges. One rate offering along these lines that have been offered by utilities is a subscription rate whereby the demand charge is incorporated into a monthly subscription charge based on the load characteristics of the customer.
- 4. *Targeted Incentives that Vary with Site Utilization:*** In this case, the level of load factor, which is a proxy for station utilization, would determine the amount of incentive or discount, increasing demand charges as utilization of the charging station increases, avoiding the need to create a new rate or transition to a different rate over time.

Examples of these four alternative paths are described in the main body of the accompanying paper. We believe any of these four paths for dealing with the demand charge issue are equally supportable. And we should also note that utilities, with stakeholder input, are continually developing new ideas for EVSP rate design that will be presented to Commissions, so this list of viable alternatives is likely to expand over time.

**In conclusion, the Alliance believes that public policy goals must be considered along with cost-of-service principles traditionally applied to utility rates. While demand charges have been proven over the years to be a means to reliably, efficiently, and fairly allocate costs to commercial customers, when applied to EV charging during this nascent stage of market development creates problems. Demand charge relief may be needed to ensure that the market is able to develop. We should not prejudge the best solution to meet specific needs of the utility and its EVSP customers. Some existing rates approved earlier by Commissions, such as non-demand billing tariffs, might be adopted or modified for the EV use cases. These cases will likely be specific to a particular utility and jurisdiction – a one-size-fits-all approach will not be realistic. Demand charge relief can take multiple forms but is critical to enable the market transformation of the EV industry.**

## Box 1. Key Recommendations

1. Recognize the public policy benefits of widespread deployment of fast-charging stations and provide demand charge relief – either waiving or reducing demand charges on a temporary basis, adopting permanent rates that are based on Cost of Service but don't assess demand charges, incorporating demand charges in subscription rates, or offering targeted incentives that vary with station utilization
2. Utilities should work with EVSPs and other stakeholders to find appropriate solutions to recommend to state regulatory commissions. Departure from strict cost of service principles is generally warranted when there is a greater public policy good to be achieved (e.g., the environmental and economic benefits of electrification), but should be done in a manner that, to the extent possible, follows foundational rate design principles.
3. Utilities and Commissions should review data and evaluate real world experience to determine whether the current schedules for returning to full demand charges where they exist are reasonable, or when customer EVSPs should transition back to service on demand charge-based rates if schedules haven't been set.

## I. Introduction

This is the second in a series of papers by the Alliance for Transportation Electrification (“ATE” or “the Alliance”) that focus on the topic of utility rate design with respect to transportation electrification, which is of increasing importance to the growth of EV markets.<sup>1</sup> The purpose of this paper is to increase understanding of the EV demand charge issue. We provide some context as to how utility costs are recovered, why demand charges for commercial customers are levied, the issues that inclusion of such demand charges in rates cause for EV charging, and some alternative solutions to address those issues.<sup>2</sup>

Electric rates that are traditionally based on cost-of-service principles (as opposed to value of services or market-based pricing) support both efficiency and equity in the provision of electric service at just and reasonable rates which are approved by state regulatory commissions. In this context, demand charges in commercial and industrial rates accurately reflect cost causation, which is a key objective of rate design. Based on foundational ratemaking principles, demand charges are a fair and efficient means of recovering the costs utilities incur in providing sufficient capacity to manage demand reliably and to meet customer demands but these charges can raise challenges when included in rates paid by EVSPs (electric vehicle service providers)<sup>3</sup>.

Specifically, while demand charges are typically appropriate for utility cost recovery for commercial or general service accounts, the low utilization of some EV charging stations can pose barriers to EV market development. This is because EV chargers can create sharp loads over short periods of time, causing high demand charges, which in turn could make the economics of deploying commercial EV charging stations a challenge. Where utilization of the charging station is low, the demand charges incurred must be spread over relatively small kWh sales by the EVSPs, resulting in what can be very high costs per kWh of charging. Recognizing this, EVSP developers are unlikely to take the risk involved in deploying charging stations in jurisdictions with high demand charges. Fewer public charging stations will hurt the development of EV markets which have attendant benefits for all consumers.

Therefore, while the Alliance believes that in the longer-term, as utilization gets to the point where demand charges don’t serve as a hindrance to the widespread deployment of EVSPs, demand charges

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<sup>1</sup> The first paper, published in July 2021, laid out a set of principles for rate design that support transportation electrification, for utility sales to residential and commercial customers, and sales by third-party or utility-owned electric vehicle service providers (“EVSPs”) to vehicle owners. In that paper, we discussed demand-based charges in utility commercial rates that has become the subject of some controversy because of their impacts on EV charging costs. In this paper, we take a deeper dive in trying to explain why demand charges are assessed, their benefits, the transitory problems they may create for utility customer EVSPs, and alternative solutions being examined and adopted across the country.

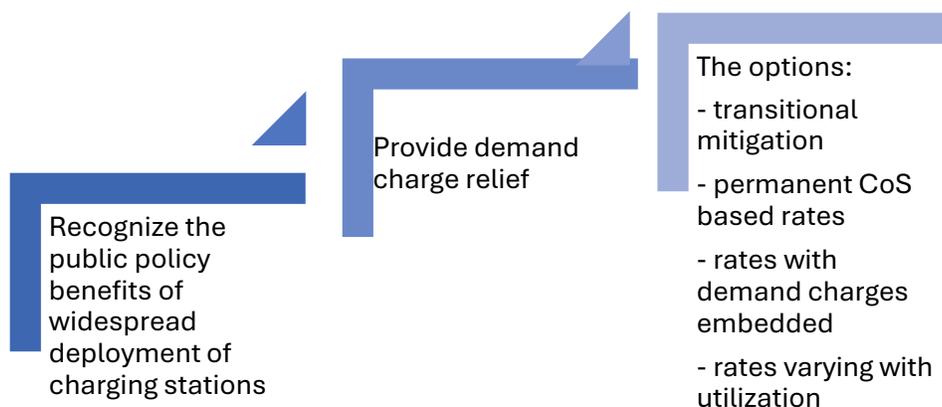
<sup>2</sup> The focus of this paper is on commercial or general service rates that include demand charges. With respect to energy supply, the subject of this paper is limited to sales to EVSPs by regulated utilities.

<sup>3</sup> There are numerous terms used to describe the charging station business, sometimes describing different aspects. EVSE (electric vehicle service equipment) is usually used to refer to the physical equipment used in the charging station. EVSP is often used to refer to the entity providing the charging service and associated networking. But because there are many business models for EV charging, it is not always straightforward who the utility customer is – it may be the owner of the EVSE, the EVSP, the host site, or even a third party. For purposes of this paper we will use the term “customer EVSP” to refer to the charging customer of record to the utility – i.e., the entity that pays the utility bills for electric service to the station.

still represent a well-supported means of ensuring reliable, efficient use of the grid and fairness to all commercial customers. But demand charges when applied to sales to customer EVSPs present an issue caused by low utilization during this nascent stage of EV market development. Since EVs come with many benefits to utilities, their customers and society at large, and because public policy considerations are part and parcel of the rate design process, the Alliance supports demand charge relief as the market develops. Such relief can take several different forms which are addressed in this paper.

The first of these solutions, which was the focus of ATE's earlier Rate Design Principles paper, is temporal demand charge mitigation. Where waiving or reducing demand charges is found to be the preferred solution, the relief should be temporary as waiving or reducing demand charges without recovery of the fixed costs they were meant to recover results in a subsidy from other customers who will be required to bear a greater share of the utility's fixed costs for the period demand charge relief is in effect. And temporal mitigation doesn't necessarily mean that there needs to be a specific timeline for re-imposing full demand charges. For example, an alternative is to offer a rate with reduced demand charges and higher energy charges as an option, with the customer EVSP able to switch to the regular C&I rate when utilization increases. But in any event, fairness and efficiency require that all customers ultimately pay the costs which they impose on the utility system. It's also important to point out that states differ in their views on adopting rate designs that depart from strict cost of service principles, or may have legal prohibitions from such departures, so this alternative may not always be available. But there are other paths which should be considered as well – including more permanent cost of service-based rates without demand charges, rates that have demand charges embedded (subscription rates), or rates that assess varying demand charges based on EVSP utilization. These alternative paths are discussed further in this paper.

Figure 1: Proposed Solution to Charging Challenges from Demand Charges in Areas of Low Utilization



While we recognize that the demand charge problem may be temporary until public and fleet EV charging station utilization increases, electric utilities have recognized this challenge and have stepped up with a variety of programs and rate designs in many States that waive or reduce demand charges, with Commission approvals. There are many alternative ways in which demand charges are waived or reduced (for a period). Examples of this type of relief includes the demand charge holiday offered by Southern California Edison which eliminates demand charges for five years and then phases them back

in over the next five years.<sup>4</sup> And there are many other examples of transitional demand charge mitigation which were presented in ATE's earlier paper.

And in addition to different means for mitigating demand charges, there are different ways in which reduced demand charges can be implemented. Temporary rate schedules applying to customer EVSPs can be developed which requires approval of a new rate. But some Commissions have approved either rebates or credits to customer bills, which can be offered through utility programs without requiring new rate design filings. The path adopted will vary by state according to precedent, legal requirements and other factors.

We must also recognize that some customer EVSPs will face longer-term utilization issues. For example, EVSPs in rural areas or underserved communities may face utilization issues for a longer period than urban locations. And as utilization increases, the charging experience drivers face may decline as charging ports become less available when they are needed. The problem is that at this point in time, we don't have a lot of data on charging station utilization, EV owner experiences, and when demand charges may become the most economic alternative for customer EVSPs.<sup>5</sup> **Thus, the Alliance also recommends that over time, utilities and Commissions should review and evaluate real world experience to determine whether the current schedules for returning to full demand charges where they exist are reasonable, or when customer EVSPs should transition back to service on demand charge-based rates if schedules haven't been set.<sup>6</sup> We believe this evaluation should occur at least every three years.**

While temporal demand charge relief is the approach taken in the majority of cases across the country, other rate design solutions for demand charge relief are emerging that don't require short-term mitigation. One path involves more permanent rate designs based on cost of service that apply to at least some EVSP use cases. For example, many utilities have commercial rates specifically designed for low demand, and/or low utilization customers that don't include demand charges at all (this is called non-demand billing, or a defined tariff for low load customers). Dominion Energy is one utility that offers such a rate.<sup>7</sup> These rates are certainly helpful for some EVSPs, but usually aren't available for higher powered DC fast charging sites. Other utilities are also offering subscription type rates where demand charges are still recovered but through some kind of a fixed monthly rate. Demand charges are

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<sup>4</sup> Application of San Diego Gas & Electric Company (U 902E) for Approval of SB 350 Transportation Electrification Proposals, Application 17-01-020, Docket No. 17-01-020, Decision On The Transportation Electrification Standard Review Projects at 111 (June 6, 2018) (available at <https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/d/6442457637-d1805040.pdf>).

<sup>5</sup> As discussed later in this paper, there is a crossover point determined by station utilization at which EVSPs will face lower overall costs with demand charges than they would if fixed capacity costs were recovered in volumetric rates.

<sup>6</sup> And there may be use cases where long-term or permanent relief is needed. In such cases, long-term subsidies from the utility, government sources, or others might be considered.

<sup>7</sup> Dominion Rate Schedule GS-2. <https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/business-rates/schedule-gs2.pdf?la=en&rev=65c74050107549f299d48689f738e948&hash=7CBE70107AE10C66B8EB5C5A1E248D12>

typically included in the monthly subscription. Pacific Gas & Electric is one utility that has established such a subscription rate.<sup>8</sup>

Another solution that some utilities have proposed or implemented is to target the demand charge incentive to utilization of EV charging stations. Such rates can start out with a significant reduction in demand charges, but as utilization increases, the demand charge discount is reduced, and a more normalized level of demand charges begins. National Grid has proposed such a tariff-based demand charge discount program in Massachusetts.<sup>9</sup> The ten-year optional “tariff-based discount program” provides a discount determined annually by assessing their load factor using the previous year average. The customer’s maximum monthly on-peak 15-minute demand rates would be billed fully, with a separate line item on their bill for the discount (100%, 50%, 25% or 0%) depending on the customer’s annual assessed load factor based on their annual average. In this program, base distribution demand and energy charges work on a sliding scale. As load factor increases, the demand charge increases and the energy charge decreases.

Finally, we must point out that demand charges can be dealt with in other ways. For example, there are technological means to deal with the issue (such as battery storage located at EVSP sites, or load management at stations that encourages or ensures use at times other than utility peaks). Such solutions provide significant benefits to the EVSP while ensuring utilities recover their costs of service and are a promising alternative. But the economics will vary by location.

This paper also addresses approaches to demand charge relief that do not work in our estimation. In this paper we discuss why we oppose proposals such as short-term marginal cost-based rates or rates based solely on utilization (so-called volumetric rates). And establishing EV service as a separate rate class with different rates than other commercial or general service customers has also been suggested but has associated complexities and issues described later.

The Alliance believes that utilities have an important role to play in this huge market transformation to reduce greenhouse gas emissions in the transportation sector and to bring economic benefits to both EV and non-EV drivers. Due to their unique position as both the supplier of electricity and the integrator of these new loads in the distribution system, utilities are well-positioned to take a leading role in this transformation. Moreover, utilities across the country have already and continue to propose solutions to the needs dictated by state goals and public policy objectives to facilitate the development of EV markets for the common good. Ultimately, we believe that utilities and their EVSP customers can and should work cooperatively to meet EVSP needs and ensure that rate design, and demand charges in particular, do not create a barrier to beneficial EV market growth.

An important caveat to this report is that in many parts of the country, the energy supply component (i.e., non-delivery charges) of sales to retail customers (including commercial) has been deregulated and customers can choose their supplier. In cases where the EVSP has a non-utility energy supplier, the energy supply transaction in most instances is not regulated. With respect to energy supply, this paper

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<sup>8</sup> Decision Approving Application for Pacific Gas and Electric Company’s Commercial Electric Vehicle Rates, Docket No. A1811003, <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=318552527> (Oct. 28, 2019).

<sup>9</sup> Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval of Phase III Electric Vehicle Market Development Program – D.P.U. 21-91. July 14, 2021. Eversource Energy and Unitil have similar programs proposed in Dockets D.P.U 21-90 and 21-92 respectively.

deals only with energy supply sales to EVSPs by regulated utilities where Commissions approve rates for such service.

Where Commissions do not approve rates for energy supply sales to EVSPs from deregulated suppliers, they do approve rates for delivery or distribution service. Distribution rates are important as they comprise about 30 percent of a customer's total bill on average (including not only the distribution system but also billing, customer service, and administrative costs).<sup>10</sup> Many utilities in deregulated markets include demand charges in distribution rates, but some do not. In this report we will not discuss demand charges in distribution rates separately, as we believe the issues and alternative approaches for demand charges in distribution rates are generally the same as they are for regulated energy supply (although measurement may be different as noted below). And in areas of the country where states still regulate vertically-integrated utilities that supply generation, transmission and distribution, it is this "bundled" service to commercial customers that will include demand charges.

In the following sections, we zero in on a specific utility cost element – fixed capacity costs. We discuss why customer demand has evolved to be the accepted means by which fixed costs are allocated among different classes of customers and to specific customers within the commercial and general service class (where EVSPs reside). We then discuss how demand charges are calculated, why they have raised concern with respect to service to EVSPs, some proposed alternatives we think don't work, and finally the Alliance's recommendations for a solution to the demand charge issue. There are also two appendices to this paper. In Appendix A, we present a short history of rate regulation of the electric utility industry to demonstrate how and why cost of service has become the basic principle for setting rates. In Appendix B we discuss all the various types of utility costs considered in the rate design process and how they are generally handled. We believe these Appendices provide important context to the discussion of demand charges and alternatives in the main body of this report.

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<sup>10</sup> <https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php>

## II. Demand Charges – Development and Use Today

### A. Why Demand Charges?

Many often ask why there are such things as demand charges in utility rates that don't exist just about anywhere else in the economy. The simple answer is that because at least in some aspects, utilities are considered natural monopolies, and as such they are subject to cost of service regulation.

Fundamentally, cost-of-service ratemaking and Commission oversight are meant to be a substitute for market competition. Natural monopolies

such as utilities can't charge what the market will bear, and in fact as described in detail in the Appendices to this paper, they are limited to recovering the costs of service. Any recovery from customers greater than costs of service would be considered monopolistic pricing. The basic premise behind cost-of-service ratemaking is that utilities should be able to recover their costs including a reasonable return on investments for monopoly services – no more and no less.

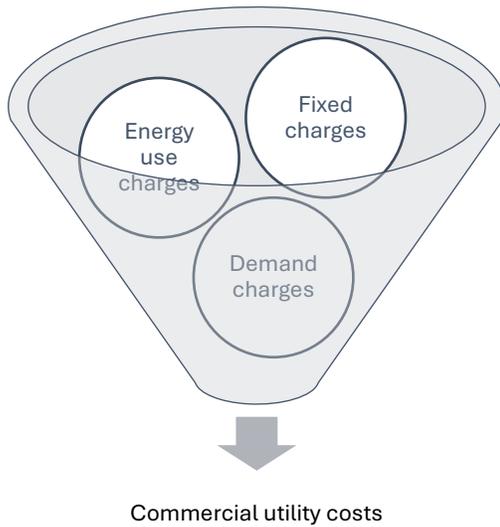
This basic principle has been affirmed many times by state legislatures, regulatory practice, and court decisions

#### Box 2. Commercial and Industrial Uses

With few exceptions, the use of demand charges has been limited to commercial and industrial classes of customers, called C&I customers. Residential customers do not have significant variations in their contribution to system peaks so the rationale for demand charges is less compelling.

As described in more detail in Appendix B, utility costs are driven by two main factors – the fixed costs of capacity (which could be generation, transmission or distribution or all three depending on the market structure in which the utility operates) and the costs of fuel for utilities owning regulated generation. Fuel costs generally are a pass-through – regulated utilities do not earn a return on their purchased fuel (and only in very limited instances for purchased power from other generators). Because the costs of fuel vary by time of use – the plants used to generate electricity constantly change during the day and the costs of fuel vary at each plant, utilities have instituted time differentiated rates for commercial customers to encourage electricity usage when costs are low and discourage use during high cost (peak) periods. And many utilities have voluntary time differentiated rates for residential customers, a default time of use rate has seldom been mandated – partly because a belief that residential customers have less ability to shift their demand or control their time of use.

Figure 2: Calculating Commercial Utility Costs



Recovering fixed capacity costs is a more complicated matter. What drives utility capacity costs and how they should be recovered? Utilities as part of their statutory or regulatory obligation must maintain sufficient capacity (again, whether it's generation, transmission or distribution) to meet the highest demand of its customers over each year with sufficient generating capacity and spinning reserves to meet customer loads (this metric is called resource adequacy). Thus, costs of capacity are driven to a significant extent by utility peak loads – even if that capacity is needed for only a few hours each year usually provided by a single cycle

gas turbine.

Were it the case that all utility customers caused the same costs to be incurred by utilities in maintaining sufficient capacity, the answer would be easy. All customers would contribute equally to the cost of capacity in each kWh sold. But particularly for C&I customers, there can be wide variation in when and how they use power – some will contribute to system peak demand significantly and some not so much. As a matter of fairness to customers in these classes, regulatory practice has evolved to charge customers who create greater costs on the electric system more than customers who create less – measured by the customer's peak load and when it occurs. These **demand charges**, incorporated into commercial and general service rates, have been found to be a fair and efficient means of recovering the costs utilities incur in providing sufficient capacity to manage peak needs reliably and efficiently (as they encourage customers to avoid system peaks) and to meet customer demands. In almost all cases, the use of demand charges has been limited to the C&I class of customers, not residential customers who have more predictable consumption patterns

## B. How Demand Charges Are Calculated

In Appendix B we describe how fixed costs of utility capacity is allocated to each of the utility's customer classes. Given that the capacity needs (and thus the primary source of fixed costs) of utilities are driven by peak demand, it logically follows that the costs imposed on the system by customer classes are directly proportional to how much the customer class contributes to the capacity needs of the system, i.e., customer class contribution to peak demand. And within the commercial or general service class of

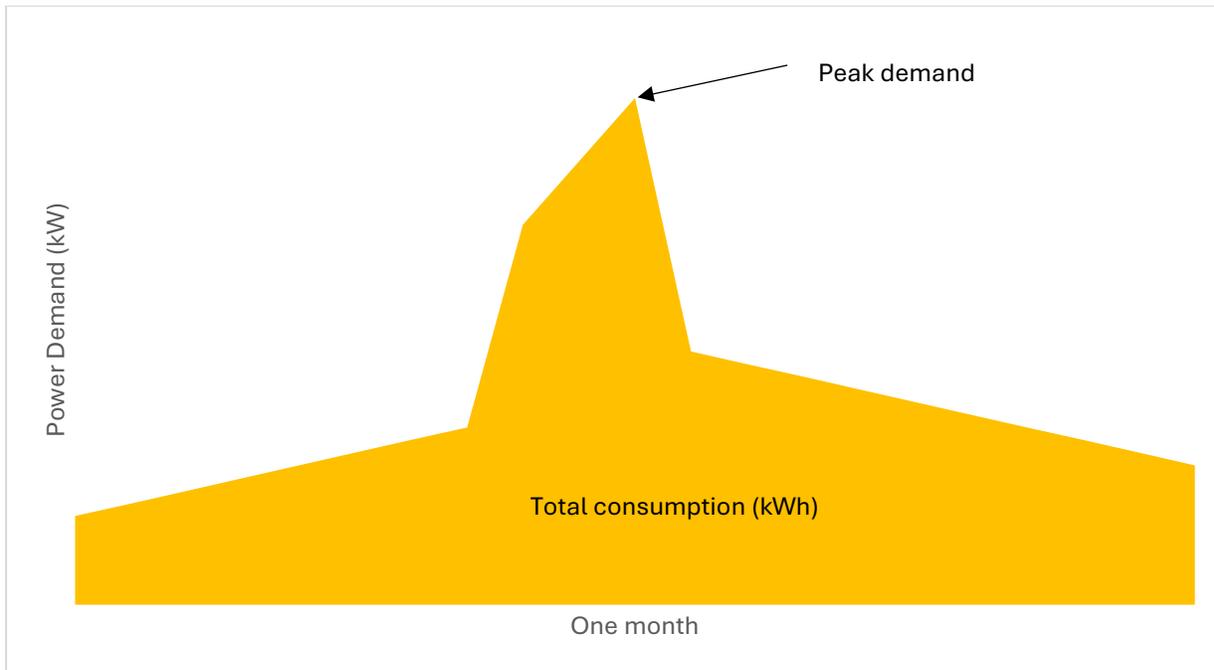
customers, in most cases customer contribution to peak is also the way that costs within the class are allocated to individual customers. In basic terms, the demand charge is the means by which these fixed costs are recovered in rates. In other words, customers who contribute the most to utility system fixed costs will pay higher demand charges than customers who have peak demands solely during off-peak periods and thus contribute less to overall system costs.

Starting at the customer level, demand charges are typically assessed based on the highest 15 minutes of average demand in a billing period. Some utilities use 30 minute or 60-minute periods. And different cost components may have different demand charges assessed – for example generation versus distribution, as discussed below. Demand charges appear as \$/kW or \$/MW per month of demand by the customer. It gets more complicated from there when examining how the demand charge is determined.

### Box 3. What is a Demand Charge?

Demand charges are the means by which fixed costs are recovered. Customers who contribute the most to utility system fixed costs will pay higher demand charges than customers who have peak demands solely during off-peak periods and thus contribute less to overall system costs.

Figure 3: Example of Peak Demand and Electricity Consumption



*In this graphic, we see total electricity consumption over a month. The demand charge is calculated by multiplying peak demand over a certain period with a dollar per kW rate. Most utilities calculate peak demand based on the highest demand during a 15-minute interval.*

The first complication is that there are different ways to measure a customer's peak demand. The first is system coincident peak demand. This measures the customer's instantaneous usage at the time the system reaches peak demand. A variation of coincident peak (CP) demand is 4CP demand which is the average of coincident peaks in a four-month period when demand is highest (e.g., June, July, August, and September each year for summer peaking utilities). This is usually considered the best measure of the customer's proportional responsibility for capacity costs – particularly for generation and transmission. But peak demand on local circuits may be different than system peaks – thus there is Local Coincident Peak which may be used to allocate distribution costs. And to complicate things even further – there are non-coincident peak measures also used in ratemaking. For example, there is a measure of peak demand for each class – Class Non-Coincident Peak Demand (which is called NCP)- which is the highest instantaneous use by a class of customers, which may also differ from the system peak. And finally, there is a Customer Non-Coincident Peak or NCP, which measures peak demand at an individual customer level instead of a class average.

Not all costs incurred by the utility are necessarily limited to any single one of these measures of demand for allocation purposes. As noted, generally generation and transmission costs would be allocated based on a customer's system coincident peak. But some utilities use Class NCP for allocating

certain costs within a class.<sup>11</sup> And as you get closer to the customer, the other measures may come into play. Local Coincident Peak may be used for the distribution system as a whole, and Customer Non-Coincident Peak may be used for equipment associated with particular customers. While these are common practices, there is no rule as to what demand measurement is applied to specific costs, and again practices vary across utilities. In general, allocating costs through class NCP is more common among utilities and Commission precedents.

But in the end, judgement is needed to make balanced and fair decisions; it is often said that there is both art and science involved in utility ratemaking after reams of evidence are submitted to the Commissioners for a final decision. And utilities have different characteristics which may lead them to different conclusions based on those characteristics. In the end, the utility will file tariff proposals in general rate cases that specify the measure to be used to determine customer demand during a billing period, the parties argue over the appropriateness of the measures, and Commissions make the determination.

Many intervenors in a rate case involving customer EVSP service will argue, for example, that because they can show that they don't contribute to the utility system annual peak, they should not be required pay demand charges. Some utilities will have programs available that would allow the utility (or third party) the ability to control the customer's load so it can't be used or is throttled down at system peak – in exchange for a discounted rate. Such rates are probably not practical for public highway charging on a corridor where the EV driver wants to charge when they show up but could be more practical for workplace charging or for fleets when longer dwell times at the charging station or flexibility as to when to charge is feasible.

Another complication in assessing demand charges is that many utilities have different demand charges that apply to different situations or customer characteristics. For example, demand charges may be set differently depending on the time that peak demand occurs, which may be periods during a day, a week, or variation by season. For example, in these situations a customer with a peak during the day in August will likely face a higher demand charge than a customer that peaks in the middle of the night in April. These variations are meant to serve some of the same purpose as time of use rates – that is, to encourage use (and particularly peak use) during times of lower cost. Demand rates may also be tiered in blocks depending on some measure of the customer's size or usage within the rate class, recognizing that even within a class larger customers impose more costs than smaller customers. And finally, some utilities have a load factor penalty. Load factor is a measure of the "peakiness" of customer demand and is measured by dividing usage (kWh) in a billing period, dividing it by the peak demand (KW), then dividing by the number of days in the billing cycle, then dividing by 24 hours in a day. A high load factor means that average use and peak use are closely aligned, while low load factors denote the opposite.

And finally, there is something called a demand "ratchet" that many utilities have adopted with respect to demand charges. A demand ratchet is a percentage of the highest peak period demand during a preceding period (often 12 months but sometimes 6 months). The percentage applied to that previous highest demand typically varies between 50 and 80 percent. The resulting amount after the ratchet has been applied becomes the floor for demand charges within the current billing period. The customer

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<sup>11</sup> Some utilities, rather than allocating based on class demand measures, allocate based on individual customer demand measures. But again, the principles and rationale for such methods remains the same as for intra-class allocation methods.

would pay either the current month demand charge or the ratcheted historic demand charge, whichever is higher. The reason that there are these ratchets is because the highest demand within the past period is probably a better indicator of the customer's contribution to system costs. Ratchets also reduce the risk of serving customers that may have wide swings in demand. Ratchets are more often used for large commercial or industrial customers and may or may not apply to rates applicable to EV charging loads. Depending on what combination of these variants a utility adopts and has received approval for in its rate case, the utility then, using recent historical data, will run calculations to determine what level of demand charges (of the different types) are needed to collect the annual revenue requirement for the commercial class of customer being evaluated and thus to be incorporated in the different tariffs applicable to that class. These are the demand charges that will be imposed on customers, including in many cases EV charging stations (EVSPs).

**In summary, ratemaking is not necessarily a precise science, and involves the balancing of many trade-offs among customers and classes. Utilities file rate design proposals during a rate case and ultimately the Commission evaluates benefits to customers and makes difficult judgements. And depending on where they provide service, utilities may be subject to different regulations and have different characteristics, which may lead them to different rate designs based on those characteristics and regulatory precedent.**

### **C. Emerging Issues with Demand Charges**

Before getting into specific issues regarding demand charges and EVs, it is important to note that the use of demand charges in general has become increasingly a topic of controversy as it relates to EV charging for C&I customers. Some suggest that peak demand is no longer an accurate way of allocating generation and transmission costs. One such argument is that more and more generation and transmission may be getting built for reasons other than meeting peak demand, such as for reducing energy costs or reducing environmental emissions. Those making the argument suggest that this is evidenced by the fact that system costs are increasing rapidly in many areas of the country without a concomitant increase in system capacity. Another argument some make is that demand charges don't necessarily account for the advantages of diversity of load within a class. The argument made is that demand charges assume each customer is a separate entity without looking at cost reductions that may occur due to other customers having complementary demand. This argument, though, ignores the fact that diversity in load is reflected in the overall fixed costs to be allocated, and is thus accounted for.

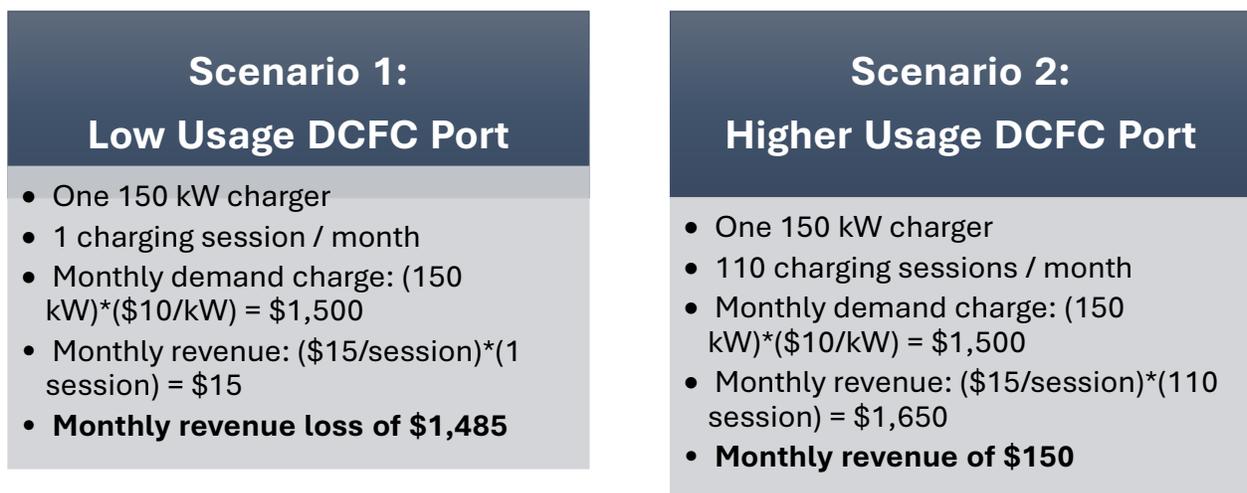
Notwithstanding these arguments, demand charges have been used for many decades – since meters were first developed that could measure energy use by time interval – and have been quite successful at meeting their objectives – again reliability, efficiency, and fairness. Demand charges are an effective method to send price signals to customers the need to shift demands to lower cost periods, which enables more efficient use of both generation (where rates are bundled) and the distribution grid. And they remain in place in most jurisdictions today.

Customer EVSPs are almost always classified as commercial or general service class customers, and thus the rates applicable to them often include demand charges. The nature of the load created by EV charging – and particularly higher voltage DC fast charging - creates peakiness – particularly today when public charger usage is fairly low in most cases. Thus, you have EVs occasionally pulling up to the

charger and creating a very significant demand over what may be a short period of time. And it may be hours until the next EV appears. The result is a load curve that shows low or no usage during a significant number of hours, but fairly sharp peaks during a few hours every day. The end result is that the EVSP would pay demand charges for those peaks but not have very many kWh sales to spread those demand (and other charges) over. In order to be profitable, the EVSP would have to charge the EV owner that very high cost per kWh which in many cases could exceed the cost of filling an equivalent ICE (internal combustion engine) car with gasoline. Such a result could be a hindrance, particularly in terms of public perception to development of a vibrant EV market that provides so many public benefits.

**So, in situations where utilization rates are low, the problem with demand charges as they relate to public EV charging amounts to a utilization problem – not necessarily a problem with the rate. In situations where there are currently too few sales to spread out fixed costs and allow the EVSP to make the charging experience economical for the EV driver, demand charge mitigation could be considered.**

Figure 4: Examples of How Charger Usage Impacts Revenue



*Note: The numbers here are estimates and used for illustrative purposes only.*

The most common response to the imposition of demand charges – particularly from customer EVSPs themselves - is that demand charges are unwarranted for EV charging and make it infeasible to develop stations in areas with high demand charges. Utilities are often subjected to criticism where their rates applicable to customers EVSPs include such demand charges. But utilities across the country have developed rates applicable to EV charging that in some way mitigate demand charges or their impacts. Others are working with stakeholders now to develop such rates. And while utilities cannot unilaterally decide not to impose demand charges - once they are adopted in a tariff, utilities must legally impose them on customers defined by the tariff. Relieving any group of customers from imposition of a currently approved tariff requires the filing of a new tariff, tariff amendment, or regulatory program, usually in the context of a general rate case which does not occur that often. Many parties intervene in those cases and make arguments on almost all sides of a given issue. Rate cases may take months. It is not until a Commission approves a tariff change that the utility can begin billing customers on a different

basis. We urge EVSPs, utilities and other stakeholders to work together collaboratively to help guide the development of alternatives when needed and understand, for better or worse, that the process takes time.

#### **D. Alternatives to Demand Charges that are not Fair and Sustainable**

There are many alternatives to demand charges that have been suggested to address this utilization/demand charge issue. One of the most common suggestions is to switch EV charging to a separate rate class or commercial sub-class. We believe this suggestion is an oversimplification of a complex issue. When considering whether EV charging should be treated as a separate rate class, or “sub-class,” there are two implications to consider – rate design and cost allocation. It may be advantageous to consider EV charging load by itself for purposes of rate design, as consideration of the load shape and driver behaviors for commercial EV charging may warrant other approaches than traditional demand charges that can better incentivize the development of charging infrastructure in public and commercial contexts and the timing and amount of charging through actionable price signals – all while collecting the requisite revenue requirements assigned to them or their rate class. However, a second question, either in parallel or subsequent to any rate design adjustments, is whether EV charging should be treated as a separate group for cost allocation purposes. This second question requires careful consideration, particularly if there is evidence from existing charging installations that EV charging is or is not contributing as much to peak costs as other commercial customers. It is important to consider whether creating a separate group for cost allocation purposes would result in higher or lower costs for EVSPs than treating EV charging as part of the overall commercial rate class.

We encourage the consideration of these questions, but caution against taking steps that would result in higher rates for EV charging than having not considered EV charging as a separate rate class or sub-class. Utilization factors at commercial charging stations are actively increasing, and as a result any cost allocation decisions that increase the share of costs for which commercial EV charging is responsible may not be reflective of actual conditions moving forward. Finally, we note that when considering whether to treat EV charging differently from a rate design or cost allocation perspective, it is important to get specific in terms of whether this applies to only DC fast charging or whether Level 2 (charging at power levels from 7.7 to 11 KW) is also included. The conclusions being drawn from EV charging data may depend on whether the EV charging load considered is primarily DC fast charging, primarily Level 2, or a combination of both. Interested parties should consider all intended and unintended consequences before moving EV charging to a separate rate class or sub class. We may be prepared to make better decisions as more data on charging use patterns becomes available.

If treating EV charging as a separate rate class, some have suggested EV charging should pay purely volumetric rates – i.e., recover all costs in a per kWh charge. Others have suggested that combining volumetric rates with time of use rates will at least cure some of the fairness and efficiency (price signal) issues. While varying volumetric rates by time of day is certainly better than not doing it, it falls short of achieving the objectives that demand charges attempt to achieve. Demand charges are typically based on the highest 15- or 30-minute period of use – TOU or time-varying rates without demand charges are much less precise and will not capture the contribution of any single customer to the costs of maintaining resource adequacy in the system. Customers would certainly rather pay higher TOU rates for the period in which their demand is highest than pay demand charges based on that peak. So, there

is less incentive to move usage off-peak under volumetric rates. It is a rough approximation of cost causation at best and does not give customers the full picture of their cost effect on the system.

But there is an even more important reason to be cautious about moving to volumetric rates on a long-term or permanent basis. The problem with demand rates generally is low utilization of charging stations in this nascent stage of EV market development. Moving to volumetric rates can reduce costs to EV charging stations when they have low utilization. But as utilization increases, there is a point at which continuing to use purely volumetric-based rates will become more expensive to the customer EVSP than current rate structures for EVSPs that include demand charges. The point at which such cross-over would occur varies by utility tariff and the structure of the volumetric rates, but that cross-over occurs at a much lower utilization rate than might be expected. Sacramento Public Utility District (SMUD) recently cited one of the few studies of the issue conducted by the Electric Power Research Institute (EPRI) that found that rates based on demand charges would be preferable over volumetric rates at about 30 percent utilization of the charging station calculated on a monthly basis<sup>12</sup>. There are probably some customer EVSPs already at that level of utilization, but it may be only a few years until many or most customer EVSPs are at or beyond that level. Some stations, however, may take much longer to reach that level of utilization.

Another form of pricing – short-run marginal costs - has also been suggested for pricing service to EVSPs. Short-run marginal costs are the costs of increasing production by one unit of output – in the case of electricity a kWh. For pricing on this basis, capacity (fixed) costs are not included at all. The argument made by its proponents is that since this is new load, as long as variable costs caused by the load are collected, existing customers are not harmed. ATE believes that rates that don't collect any fixed costs are unfair to existing customers who must bear the full fixed-cost burden even though capacity they are paying for is serving the needs of the new customers. And short-run marginal costs, even if implemented on a time-of-use basis only provides rough price signals to customers to avoid system peak demands. It also needs to be noted that since distribution has very little variable costs associated with it, short-run marginal costs would be close to zero for these assets. We believe that all customers who use the electric system should contribute to its fixed cost recovery. It is important that both existing and prospective customers share in the recovery of fixed costs.

#### **E. ATE's Preferred Alternatives for Demand Charge Relief**

The foregoing analysis leads us to ATE's recommendations. In our earlier Rate Design Principles paper, we focused on temporal mitigation of demand charges as the preferred solution. We suggested that demand charges should be reduced or waived for a time-limited period until utilization increased to the point that demand charges were the economic alternative for customer EVSPs. Our general belief is that EVSPs should be provided relief from demand charges (when needed) to ensure beneficial charging station development can continue. Since the publication of our initial paper, there have been more options emerging for dealing with the demand charge issue. We now expand our list of alternative solutions to include other options which are more permanent in nature and may be preferable in some

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<sup>12</sup> Boyce, Bill. "Sacramento Municipal Utility District Commercial EV Rates History." Presentation to California PUC and California Energy Commission En Banc Workshop, October 12, 2021.

circumstances to temporal mitigation of demand charges. We discuss these alternative rate design below.

### ***Alternative Path 1 – Short-term Mitigation of Demand Charges***

Under this alternative, demand charges applied to rates for service to EVSPs are either waived or reduced during a transition of market transformation when utilization of charging stations is low but should be reinstated either after utilization becomes sufficient or gradually over time while utilization is increasing. The basis for recommending demand charge relief on such a basis is that while demand charges remain an important part of CoS considerations for commercial customers, we also believe that the development of EV markets will have significant environmental and economic beneficial effects to society, to utilities and to all customers both EV owners and non-participants. The rapid deployment of charging stations is needed to mitigate consumer range anxiety concerns and to make certain use cases such as fleets, transit, and medium- and heavy-duty market penetration feasible. If demand charges are standing in the way, public policy dictates that we should deal with them.

But under this alternative path we recommend transition back to demand charges where and when utilization of charging stations becomes sufficient so that demand charges don't stand in the way of market development. Periodic review of rates applied to EV charging against the levels of utilization occurring is needed. Many states have adopted requirements for the utilities to file and revise Transportation Electrification Plans (TEPs) every three years, which are reviewed by stakeholders and approved or modified by Commissions. We think this cadence of review for the TEP could be efficiently combined with rate design reviews and specifically demand charge mitigation measures.

Once a utility departs from strict cost of service to provide such transitional relief, there is no one best or correct alternative. And in fact, utilities across the country that have developed demand charge relief-programs have used a variety of approaches that meet their own needs and the needs of their customers. These range from demand-side holidays where demand charges may be dropped for a certain period and then phased back in, rates that have demand charges that vary with utilization, rates with demand limiters that set a cap on demand charges, and others. One caveat to all these options is that the EVSP must be separately metered from the rest of the customer's load. In trying to deal with issues specific to EVSPs, we should not relieve other commercial loads at the same site as the EVSP from demand charges.

In ATE's previous Principles of Rate Design paper, we provide a listing of a broad sample of these types of demand charge relief programs.

While in many cases, the period in which demand charge relief is to remain in place has been specified in a Commission Order, we believe there should be some flexibility in the transition back to fully applied demand charges because we currently don't know very much about charging station utilization and how it will grow. And it is important to note that utilization will likely not be uniform within a utility's service territory. There are some charging station locations, for example in more rural areas, where utilization may never reach the level where they can economically absorb demand charges. Other areas may already be at utilization levels where demand charges can be assessed without causing harm to EV drivers who should be the focus of such regulatory programs.

And we also mention that rate options can be designed that are permanent in nature (i.e., they lack a timeline), but are targeted to be used as an option only for the period when they are a better alternative for the customer EVSP. For example, Xcel Energy-Colorado rates S-EV-CPP and proposed S-EV drastically lower the demand charges applicable to most commercial customers and move those costs over into time-varying energy charges and (in one case) a CPP charge. This gives customer EVSPs and others the ability to select the best rate for them when it's best for them – preserving their ability to switch back to traditional demand-charge focused rates when it's right for them.<sup>13</sup>

Finally, it's important to note that not all utilities have the flexibility to adopt rates that vary from strict cost of service even for a limited time, either because of reliance on precedent, state statutes or regulatory policies. In these cases, other options may be necessary.

### ***Alternative Path 2 – Permanent CoS-Based Rates without Demand Charges***

Commercial rates without demand charges for users with certain load profile characteristics and not having significant demand is one approach for a permanent rate that does not include demand charges. However, these rates, available from many utilities, are mostly useful for Level 2 charging or the lowest power levels of DC fast charging. Higher demand as would be consumed by most DCFC EVSPs is still assessed demand charges for most of these utilities. Not assessing demand charges to high demand customers would be a departure from cost of service.

Dominion Energy is one utility that has such a non-demand billing rate available to any customer, Rate Schedule GS-2.<sup>14</sup> Non-demand billing applies to customers whose kWh usage for the current month does not exceed 200 kWh per kW. Minimum demand is 30kW and maximum demand is 500 kW.

### ***Alternative Path 3 – Rates with Embedded Demand Charges***

Another approach to more permanent cost of service-based rates are subscription rates which are gaining in popularity. In subscription rates, the fixed costs are incorporated into a monthly subscription charge to the EVSE. Pacific Gas & Electric in California began offering a monthly service subscription option in May 2020 PG&E offers two subscription rate options: one for workplace or parking lot charging, up to 100 kW, and one focused on fleets and public DCFC stations, with demand over 100 kW. Commercial EV charging customers choose a monthly subscription level based on their anticipated kW usage, selecting blocks of 10 kW up to 100 kW at \$12.41 per block. For larger users, there are 50 kW blocks at \$85.98 per block with no cap for peak demand. Subscribers are also billed a monthly service fee as well as a fee corresponding to their selected power level. Subscribers are charged an overage fee if their usage exceeds this subscription level past the three-month billing grace period. Per kWh energy

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<sup>13</sup> The company refers to these as “S-EV rates” but consistent of two optional rates: the revised S-EV (secondary voltage, TOU EV Service, and the previous S-EV-CPP, with a CPP component. See Joint Post-Hearing Statement of Position of Public Service Company of Colorado and Trial Staff of the Colorado Public Utilities Commission, [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=971988&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=971988&p_session_id=) (May 9, 2022).

<sup>14</sup> Dominion Rate Schedule GS-2 op. cit..

charges are still subject to Time-of-Use (TOU) rates, but the uncertainty around the demand charge is alleviated.<sup>15</sup>

#### ***Alternative Path 4 – Targeted Incentives that Vary with Site Utilization***

Rate designs are beginning to emerge, as discussed below, where demand charge assessment is tied directly to station utilization in the tariff. National Grid has proposed such a tariff-based demand charge discount program in Massachusetts.<sup>16</sup> The ten-year optional tariff-based discount program provides a discount determined annually by assessing the load factor of the EV charging site using the previous year average. The customer's maximum monthly on-peak 15-minute demand rates would be billed fully, with a separate line item on their bill for the discount (100%, 50%, 25% or 0%) depending on the customer's annual assessed load factor based on their annual average. In this program, base distribution demand and energy charges work on a sliding scale. As load factor increases, the demand charge increases, and the energy charge decreases. Where the load factor is greater than 15%, the demand charge discount goes away, and the customer pays the same level of demand charges as a regular customer on the commercial rate. This is a limited term alternative that is to be re-evaluated in the future. Since the National Grid filing, other utilities have offered similar types of rate designs that assess demand charges based on utilization within the tariff itself.

It's important to note that this is still a nascent market and we do not yet have significant experience with the impacts of alternative rate designs. And utilities are proposing new alternatives on a regular basis which should be considered. The list above is not a static list and will expand over time. As we develop more experience with the application of demand charge relief alternatives already in place in many states, we will develop a better sense of how best to deal with demand charges as they apply to EVSP service. Collection of data and collaboration between customer EVSPs and utilities to address the issues will be critical in ensuring the desired end result – a good experience for the EV driver.

#### **F. Key Recommendations and Conclusions**

ATE's key recommendations are as follows:

- 1.** Recognize the public policy benefits of widespread deployment of fast-charging stations and provide demand charge relief – either waiving or reducing demand charges on a temporary basis, utilizing cost of service-based rates without demand charges, adopting rates with embedded demand charges, or offering targeted incentives that vary with site utilization.
- 2.** Utilities should work with EVSPs and other stakeholders to find appropriate solutions to propose to the Commissions. Departure from strict cost of service principles is generally warranted when there is a greater public policy good to be achieved (e.g., the

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<sup>15</sup> National Association of State Energy Officials, Western Interstate Energy Board, and Utah Clean Cities Coalition. Demand Charges & Electric Vehicle Fast-Charging: An Intermountain West Assessment. October 2021.

<sup>16</sup> Petition of Massachusetts Electric Company and Nantucket Electric Company, op. cit.

environmental and economic benefits of electrification), but should be done in a manner that, to the extent possible, follows foundational rate design principles.

3. Utilities and Commissions should review data and evaluate real world experience to determine whether the current schedules for returning to full demand charges where they exist are reasonable, or when customer EVSPs should transition back to service on demand charge-based rates.

In conclusion, ATE believes that public policy goals must be weighed against cost-of-service principles traditionally applied to utility rates. Demand charges have been proven over the years to be a means to reliably, efficiently, and fairly allocate costs to commercial customers. However, demand charge relief for EVSPs is likely needed to help to increase deployment of commercial fast charging stations when charging site utilization is initially low. It is largely a utilization problem – not a problem with the efficacy of demand charges themselves. As utilization increases, the effects of demand charges in rates will be lessened and in fact rates with demand charges at some point of usage become more economical than alternatives based on usage only (so-called “volumetric” rates). However, there may be charging stations located in rural or underserved communities or other locations where utilization remains low for longer. This utilization situation may never be resolved to the point that demand charge relief is unwarranted.

The Alliance’s recommendation is for regulated utilities and Commissions to recognize the public policy benefits of widespread deployment of charging stations and to provide demand charge relief – whether temporary or longer-term as needed. The Alliance believes that all the rate design paths suggested here are viable alternatives, and the rate design developed should take into account the needs of utilities and their EVSP customers. We do not subscribe to the notion of a one-size-fits-all solution across all of the utilities and state Commissions. But we believe that these principles and alternatives provide a series of best practices that can be deployed effectively in multiple jurisdictions. Demand charge relief can take multiple forms but is critical to enable the market transformation of the EV industry and realization of the benefits that accrue from electrification.

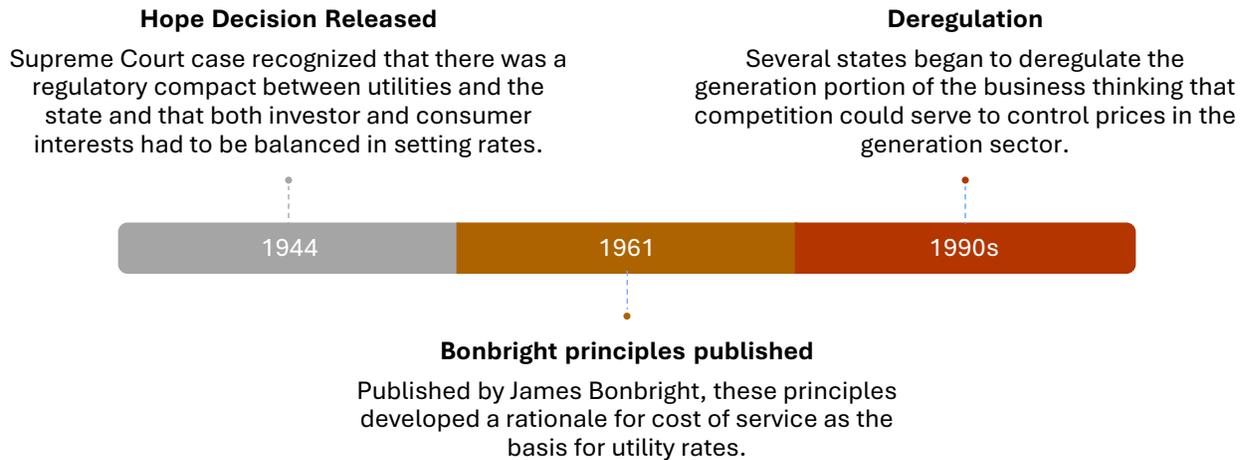
*This paper is a product of the ATE Task Force on Rate Design. The Task Force was established in the spring of 2020 to assess the broad range of rate design issues for residential and commercial customers that arise when state public utility commissions review TE rate proposals developed and filed by regulated utilities. Its primary goal was to share information on best practices in rate design across the multiple sectors within ATE, namely regulated utilities, auto OEMs, EVSPs, and other TE stakeholders. Another goal was to develop a more proactive position among ATE members on rate design as the entire EV ecosystem accelerates adoption of EVs and deployment of charging infrastructure across the country. The task force resides within the larger Policy-Regulatory Committee of ATE and reports up to the Board of Directors. The facilitators and principal authors of this consensus-based document were Philip B. Jones, Executive Director, and Bruce Edelston, Senior Advisor of ATE. They can be reached at [phil@evtransportationalliance.org](mailto:phil@evtransportationalliance.org).*

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# Appendix A

## A Brief History of Regulation: Why Cost of Service?

Figure 5: 20th Century History of Regulation



While many believe that the monopoly nature of the electric utility and thus concerns about its ability to gouge customers was the motivating factor behind the decision to regulate electricity prices, the reality is a bit more complex. In fact, the origins of public utility regulation go back to an 1876 U.S. Supreme Court decision involving the storage of grain and the concept of a state agency determining “the public interest.” The case, *Munn vs. IL*, involved whether the state could regulate prices for the storage and transportation of agricultural products. The grain storage operator argued that the State was depriving it of its rights of due process under the Fourteenth Amendment to the Constitution. The Court ruled that the activity in question, grain storage, was “affected with the public interest” and thus subject to price regulation by the State.

Later Supreme Court cases expanded this authority to other cases and industries, but it is interesting to note that the monopoly theory of regulation really came later – beginning with the *Smyth vs. Ames* Supreme Court case in 1898 which found that a railroad was a public highway by virtue of the fact that eminent domain was granted by the state and was therefore subject to regulation. And the pre-eminent case establishing state public utility regulation didn’t come until the Hope decision of 1944, which essentially recognized that there was a regulatory compact between utilities and the state and that both investor and consumer interests had to be balanced in setting rates that are “just and reasonable”.

There are industries that are not essential to the public interest but exhibit monopoly characteristics and are not regulated. In these cases, there is usually a close substitute for the monopoly product or there are no barriers to entry. DeBeers diamonds is often cited as an example of an unregulated monopoly. But electricity was, at its beginnings, and is even more so today an industry that is vital to serving the

public interest and it is at least in some respects still a natural monopoly – and thus is subject to rate regulation to varying degrees.

With respect to the monopoly aspects of public utilities, economic regulation occurs at both the state (for retail or end use sales) and at the federal level (for wholesale sales and interstate transmission) and is pervasive. State regulation occurs at state public service or public utility commissions in 49 of the 50 states and the District of Columbia.<sup>17</sup> These commissions regulate the rates at which private utilities offer service, the terms and conditions of service, issuance of securities, security, and reliability, in many cases require integrated resource planning, and other areas that vary by state. The bottom line is that private utilities, with respect to services considered to be of a monopoly nature, have to receive state permission before changing the rates or any provisions of service to any of their customers. Utilities also have an obligation to provide service (which may be energy supply or just delivery service) to all customers within the defined geographic area of their service territory – in exchange for which they are entitled to earn a fair return on their investment – the so-called regulatory compact which governs the nature of the industry.

Going back to the historical perspective, once it was determined to be a natural monopoly yet “imbued with the public interest”, the question then becomes what forms of regulation were used and why did the U.S coalesce around cost-based or cost of service regulation? In the early 20th century when state regulatory commissions were formed, there were no guidelines or textbooks on how to regulate and much of it was by trial and error. Some commissions attempted to assess the fair market value of utility assets while others relied on original costs of those assets. In fact, in the Hope decision of 1944, the Supreme Court decided that there was not a single method to set rates that properly balanced investor and consumer interests in all cases. Because Hope explicitly permitted rate setting based on depreciated original cost and because it was much easier to implement than other methods, it became the de facto standard across the country by the mid-20th century.

One of the most important treatises on rate regulation, *Principles of Public Utility Rates* by James C. Bonbright published in 1961, discusses the theory and practice of cost of service (“CoS”) ratemaking. Cost of Service is defined as the capital and operating costs the utility incurs in providing service to customers within its regulated service territory. In most cases, capital costs are measured the historical or embedded costs incurred by the utility, and deemed to be prudent, when the relevant capital cost was incurred. Utilities as a matter of practice are allowed to earn a return on the equity portion of such capital investments at a level set by state regulatory commissions and allowed to recover the interest costs of any debt incurred. State regulatory commissions also control the relative portion of debt and equity in the utility’s capital structure. All operating costs also must be approved by state regulatory commissions and generally recovered without markup.

The Bonbright principles, while based on practices in use at its publication, for the first time developed a strong rationale for cost of service as the basis for utility rates but further described how cost of service ratemaking should be implemented to achieve the proper investor/customer balance. The main principles espoused by Bonbright that are important to this discussion were:

1. sufficiency to attract investment;
2. fairness among and between customers;

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<sup>17</sup> Nebraska has no private electric utilities and thus no state-level electric utility regulation.

3. efficiency, discouraging waste and providing proper price signals;
4. acceptability to customers, and;
5. consistency with public policy objectives.

The last might be surprising, but even Bonbright suggested that departures from pure cost of service may be desirable if there are over-riding public policy objectives that the commissions may wish to achieve.

Over the last couple of decades, regulated utilities have implemented new rate designs and innovative regulatory frameworks to advance a number of different policy goals. For example, mandated targets for renewable distributed energy resources (e.g., solar PV) have led to the establishment of new tariffs and riders (e.g., net energy metering) that depart from CoS principles. Recently, many state regulators are beginning to consider performance-based ratemaking which incentivizes utilities to operate more cost-efficiently.

These are just a few examples of changes in ratemaking over the years intended to help the state achieve public policy objectives, but they have not been without debate. Similarly, utilities are being asked to implement solutions to facilitate the advancement of the public policy goals of increasing EV adoption and access to EV charging. In the main body of this paper, we discuss in detail the issue of demand charges faced in many instances by EVSPs, which have become a barrier in providing EV charging services. Some additional helpful background to that discussion is a discussion of utility costs, rate classes, and how total costs are allocated to rate classes. These issues are discussed in Appendix B.

## Appendix B

### The Commercial and General Service Rate Design Process: Utility Cost Causation and Recovery

Once cost of service principles have been designated as the means for rate regulation as detailed in Appendix A to this paper, the first step in rate development is to identify and classify what those costs are. There are many ways to classify and categorize the costs incurred by electric utilities and other suppliers in providing electric service. The formal way in which costs are accounted for in developing rates is the FERC Uniform System of Accounts which has accompanying rules for cost categorization and is very detailed. But for the purposes of this paper, we will look at costs at a much higher level to better understand what costs are incurred and how they are ultimately recovered by utilities. In this regard, there are two main types of costs that utilities incur in providing service to customers – fixed and variable. Fixed costs are those that do not vary with electric output, at least in the short term, and include, for example, the capital costs of generating plants, transmission towers and distribution system poles, wires, meters, and billing systems. Most fixed costs are included in a utility's rate base based on their historical (original) cost and recovered from customers over the depreciation lifetime of the asset. But before these assets are added to rate base, they often must undergo a review by regulators to ensure that the costs were prudently incurred. Incurred costs are often disallowed to some degree. And some states now require pre-authorization of major expenditures by the utility as well.

Investor-owned utilities (also referred to herein as private utilities) raise money from the capital markets (both debt and equity) to develop these capital assets (including the costs of construction) and are allowed to earn a fair return to equity investors on those assets. Some states allow utilities to recover the financing costs of major assets during construction, but as a general matter the costs of capital are recovered in rates in addition to the actual costs of the assets. The level of the equity return allowed is set by state regulatory commissions in utility rate cases and is almost always a contentious matter. Some fixed costs, rather than being added to rate base, are expensed as they are incurred – often short-lived assets such as software, or overhead costs like employee salaries. The depreciation expense of all capital assets, based on their historic embedded cost, plus a weighted return on capital (based on the level of debt and equity, the actual cost of debt, and the allowed return on equity) are included in the utility's total revenue requirement which is the total amount of dollars utilities are authorized to collect from customers. Fixed costs are particularly important in the electric industry because it is one of the most capital-intensive industries in the U.S. economy. All of these complex issues are described in detail by the utility in a petition and testimony to the Commission, litigated with the intervening parties, and decided ultimately by the Commissioners in what is called a general rate case (GRC).

The second type of cost incurred in providing electric service is variable costs, which are costs that are directly related to short-term changes in electric output by the utility. The largest source of variable costs is the costs of fuel to power generating plants and the costs of power purchased to meet customer demand. Unlike fixed costs, utilities do not earn a return on variable costs (there are a few exceptions – for example, some utilities are allowed to earn a return on purchased power costs as an incentive to make optimal fuel mix decisions). And in many cases, fuel costs incurred by utilities are recovered almost as soon as they are incurred fuel or power adjustment clauses outside of a general rate case. For

many utilities, fuel represents a significant proportion of total annual utility costs and having to wait for permission to recover costs in a future rate case could create significant financial concerns for utilities. Other variable costs as well may be significant or otherwise critical to the utility's mission and thus candidates for faster recovery. Thus, what is known as "riders" have been developed to add certain variable costs to monthly utility bills and collect them soon after they are incurred.

There are some costs that can be either fixed or variable. The prime example is O&M costs. For example, some O&M costs are necessary whether or not a plant is generating power – such costs would be fixed or constant. Other O&M costs are incurred when the plant is generating and vary with the level of output – those are variable costs. Typically, in either case, O&M costs are expensed and recovered as they are incurred, rather than included in rate base.

Questions are often asked as to why fixed and variable costs are considered separately in electric pricing, while one never sees such a differentiation in most any other service or product. The answer relates to cost-of-service principles and the related principle of cost causation. It would of course be possible to add up all annual costs of the utility, divide that number by the expected electricity (kWhs) to be sold, and come up with a price per kWh to be paid by all customers. This is known as a purely volumetric form of pricing, as monthly bills are entirely based on usage.

But think of the unfairness of such an approach. Residential customers with would make the same contribution toward fixed costs per kWh as industrial plants that contribute much more significantly to the fixed costs of generating capacity and/or building out the grid to meet customer needs. And there would be no incentives to reduce or shift peak demands. Among the Bonbright Principles, and the objectives of rate regulation in every state is to both promote efficient use of electricity and allocate costs fairly. Efficiency is achieved according to economic theory when customers face prices based on costs. If all customers impose the same costs, they would all pay the same price, but if they impose different costs on the system, customers would pay different prices to achieve efficient results.

This is the theory of cost causation – consumers will use the right amount and the utility system will be optimized when consumers pay the costs they impose on the system. The principle of cost causation is also central to the objective of fairness. Consumers paying according to the costs they impose on the electric utility will not be subsidized by other consumers, nor will they be subsidizing other consumers. And there will not be incentives for utilities to over- or under-produce, appropriately conserving resources.

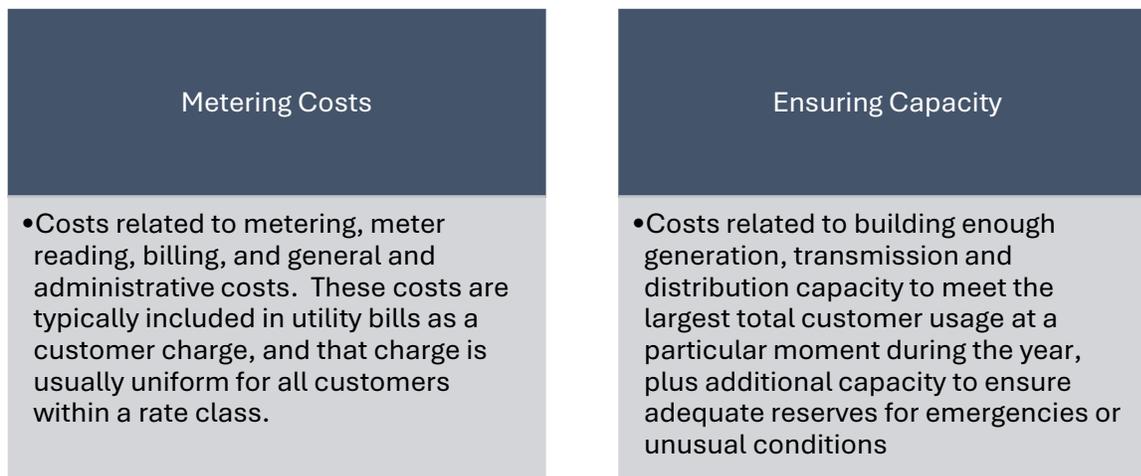
Of course, in an economic and technical system as large as electric utilities, getting prices to match cost causation exactly is almost impossible. And as mentioned earlier, there are often public policy reasons for departing from these cost causation principles. Some of these important departures will be discussed further below. But still, it is important to remember that pricing based on cost causation remains a core objective of rate regulation.

In looking at cost causation, it is again important to think of the two types of utility costs – fixed and variable. As a general matter, the causation of variable costs is the same for any two customers using electricity at the same time. The primary variable cost – the cost of fuel – is charged to all customers according to their use. It is true that the fuel costs incurred by utilities varies with time, and by season. More fuel is used, and less efficient power plants may have to be run during times of peak customer demand, so variable costs are higher during those periods. These differences, though, are caused by all

customers in the same way (there are of course some exceptions, such as where a customer has a right to purchase power from specific types of generators or where customers sign up for a “green” rate). The fact that variable costs vary with time is the rationale for time of use (TOU) rates, which come in many forms – real-time prices, hourly prices, changing prices over defined periods during the day or week, rebates for moving usage off-peak, seasonal rates, and more. TOU rates reflect cost causation and provide increased efficiency in use of the system. TOU rates are used differently for different types of customers. Residential customers often have voluntary TOU rates available, and there may also be EV-specific residential time-of-use rate – but TOU rates are rarely mandated for residential customers for various reasons. But for most commercial and larger customers, time of use rates of some kind are usually mandatory. For larger users, TOU rates help ensure that customers face the right price signals for improving efficiency and again also provide for fairness in the allocation of costs by ensuring those using power off-peak don’t have to subsidize those using power on-peak.

Thus, variable costs across customer classes are pretty uniform although in reality, there are certain types of variable costs that may be allocated to customers differently. But there are rarely significant differences in variable/fuel costs paid across customer classes. And while there are some arguments about whether variable costs have been prudently incurred, those debates are fairly low key compared to the debate over allocation of fixed costs. The remainder of this paper will focus on fixed cost allocation and recovery in rates, and the demand charge in particular.

Figure 6: Two Main Sources of Utility Fixed Costs



So, what about fixed costs? How are they recovered? There are two main sources of fixed costs discussed earlier – first are those related to metering, meter reading, billing, and general and administrative costs. These costs are typically included in utility bills as a customer charge, and that charge is usually uniform for all customers within a rate class.

The second and predominant fixed cost incurred by vertically-integrated utilities are those related to building enough generation, transmission and distribution capacity to meet the largest total customer usage at a particular moment during the year, plus additional capacity to ensure adequate reserves for

emergencies or unusual conditions. The instantaneous highest use by the total customer base during the year is the utility's annual peak demand, measured in kW or MW and is what the utility must build or procure capacity to satisfy. Capacity to meet peak demand is made up of physical supply resources such as nuclear, gas, coal, and renewable resource facilities, demand-side resources such as energy efficiency or demand response (including from EVs), distributed energy resources (even EVs which may be able to provide resources to the grid) and purchased power. Utilities must have enough supply and demand-side resources to meet this peak demand when it occurs. Storage may eventually allow the utility to reduce its capacity needs to meet peaks, but there is still very little of it on the grid today. For utilities operating in deregulated markets, delivery service is still regulated, and costs are also driven by customer peak demand. But energy suppliers do not have an obligation to build to meet peak system demand, so energy supply cost structures are different.

Given that the capacity needs of utilities are driven by peak demand, it logically follows that the costs imposed on the system by customers are directly proportional to how much the customer contributes to the capacity needs of the system, i.e. customer contribution to peak demand. And in fact, this is the primary means by which capacity costs are allocated to customer classes (and in the case of non-residential customers, within customer classes) and ultimately recovered. These "demand charges" are not usually imposed on residential customers because there is less difference within that customer class in contribution to peak demand between customers and because demand-reading meters would be necessary which add to costs (there is often cost differentiation in the residential sector through inclining or declining block structures, but that's a subject for another paper). But capacity cost recovery within commercial and industrial rate classes are almost always based on contribution to system peak demand via demand charges (some smaller commercial customers for some utilities can choose from available non-demand-based rates. For the EV sector, these are most likely available only for Level 2 charging).

So now that we have a system of assigning fixed and variable costs to customers, how are the ultimate rates set? First, the revenue requirement (the total amount of recoverable costs, including return on equity) has to be allocated to individual customer classes. The actual classes to which costs are assigned vary by utility. In almost all cases there are residential, commercial (sometimes called general service) and industrial (or manufacturing) classes – sometimes sub-divided based on service voltage, type of use, or a combination of factors. Many utilities have a separate rate class for street lighting which has similar usage as commercial customers but very different demand patterns. Some utilities have a separate rate class applicable to transit systems or railroads. And utilities with large agricultural loads often have a rate class for irrigation pumping. The general rationale for developing a rate class is to group customers together that have similar load profiles.

As discussed in the body of this paper, some EVSPs and other EV stakeholders often argue that service to EVSPs should be a separate rate class. This would be a significant departure from traditional utility practice that does not assign rate classes to specific technologies, but rather bases such assignment on load profiles of the customer class. EVSPs do not have significantly different load profiles than other members of commercial or general service rate class. But perhaps more importantly, developing a separate rate class would likely end in a worse outcome for customer EVSPs, because in the process of allocating total costs to rate classes, EVSPs would not get the benefit of diversity of load that they get by being in a larger class, and thus would have more costs assigned in a cost-of-service study. And being a separate rate class would not by itself solve any of the problems that currently exist in deciding between

volumetric versus rates based on demand charges. And it is important to note that utilities can and do offer special rates within rate classes that don't require the recipients of such rate treatment to be a separate class.

No matter what rate classifications are used by the utility and what customers are defined to fall within each rate class, the revenue requirement need is allocated to classes based on the relative costs of the utility to serve each class. These relative costs are determined by utilities in class cost of service studies and are reviewed in utility rate cases before state utility commissions. There are many different ways in which such studies are conducted, and a discussion of these methodologies are beyond the scope of this paper. The percentage of costs assigned to each rate class are applied to the utility's total revenue requirement thus determining each class's revenue requirement responsibility.

Once the revenue requirement is allocated to customer classes based on their relative costs to serve (an often contentious exercise itself), the more detailed and complex part of the rate design process begins – how the revenue requirement for each customer class will be recovered from customers within the class. As we mentioned, in this paper we discuss that process only for the commercial or general service class of customer within which customer EVSPs will fall, and we have focused only on how the costs of utility capacity are recovered within that class. Specifically, the fixed, capacity cost portion of commercial rate design, just like inter-class allocations, is based on contribution of the customer to peak demand, or demand charges and is a major portion of bills paid by commercial customers.

The other aspects of cost recovery within the commercial and general service customer classes which have already been discussed include customer charges (fixed per customer), fuel (and other variable) costs, otherwise known as consumption costs which most often vary by time of use and are measured in kWh, and in some cases separate distribution or delivery charges (which may be based on demand or kW again). There are other costs that may be recovered through riders (e.g., in some cases energy efficiency expenditures or environmental remediation costs might be recovered through riders). And there are almost always taxes and local government franchise fees to be collected. Some utilities also collect contributions to public benefit funds that are used for public policy purposes.