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EV Retail Rate Design 101

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Introduction

Electric vehicle (EV) adoption has increased significantly over the past several years. More than 640,000 light-duty plug-in EVs were sold in the US in 2021, which was more than twice the number sold in 2020. Driven by existing state and federal financial incentives as well as increased choice in electric models, EVs are popular among car buyers and now account for more than 1-in-10 of all light-duty vehicles sold in the US. At the state-level, total California EV sales recently passed one million, while New York, Washington, and Florida each have more than 100,000 total EVs on the road.

State regulators and policymakers are addressing barriers to EV adoption, integration of EVs into the electricity system, and the equitable sharing of benefits among EV owners and other electricity customers. One of the most significant activities among state utility regulators is the development of EV-specific retail rates. There are a number of EV retail rate designs reflecting different objectives and design options (see Figure 1). We introduce and describe the considerations for EV retail rate design, including motivations, metering configurations, cost recovery approaches, energy and demand charges (e.g., time-differentiated rate designs, locational-differentiated rate designs), charging controls, interactive grid services, and load flexibility. We synthesize recent experience and identify resources for more detail and additional information.

The information in this document is relevant for all types of EVs using the utility electricity system for charging (e.g., light-duty vehicles, medium-duty vehicles, and heavy-duty vehicles) and across all customer classes. We do not discuss rates that non-utility, third-parties may impose for using their charging networks. In addition, we focus on EV-specific rates and not retail rates for other DERs (e.g., net energy metering) that may have implications for EV charging and adoption. Finally, the document is an introduction to the process of designing EV retail rates and we do not present the relative success of specific rates in achieving stated objectives or outcomes.

For more information on:

- Electric vehicle sales data, see The Alliance for Automotive Innovation's *Electric Vehicle Sales Dashboard* at https://www.autosinnovate.org/resources/electric-vehicle-sales-dashboard and Argonne National Laboratory's *Light Duty Electric Drive Vehicles Monthly Sales Updates* at https://www.anl.gov/es/light-duty-electric-drive-vehicles-monthly-sales-updates
- EV-related questions and issues being addressed by state regulators, see Harper, C., G. McAndrews, and D. Sass Byrnett (2019). *Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators*. Available at: https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE

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- Other DER retail rates and implications for EV adoption, see Satchwell A., P. Cappers, and G. Barbose (2019). *Current Developments in Retail Rate Design: Implications for Solar and Other Distributed Energy Resources*. Available at: https://emp.lbl.gov/publications/current-developments-retail-rate

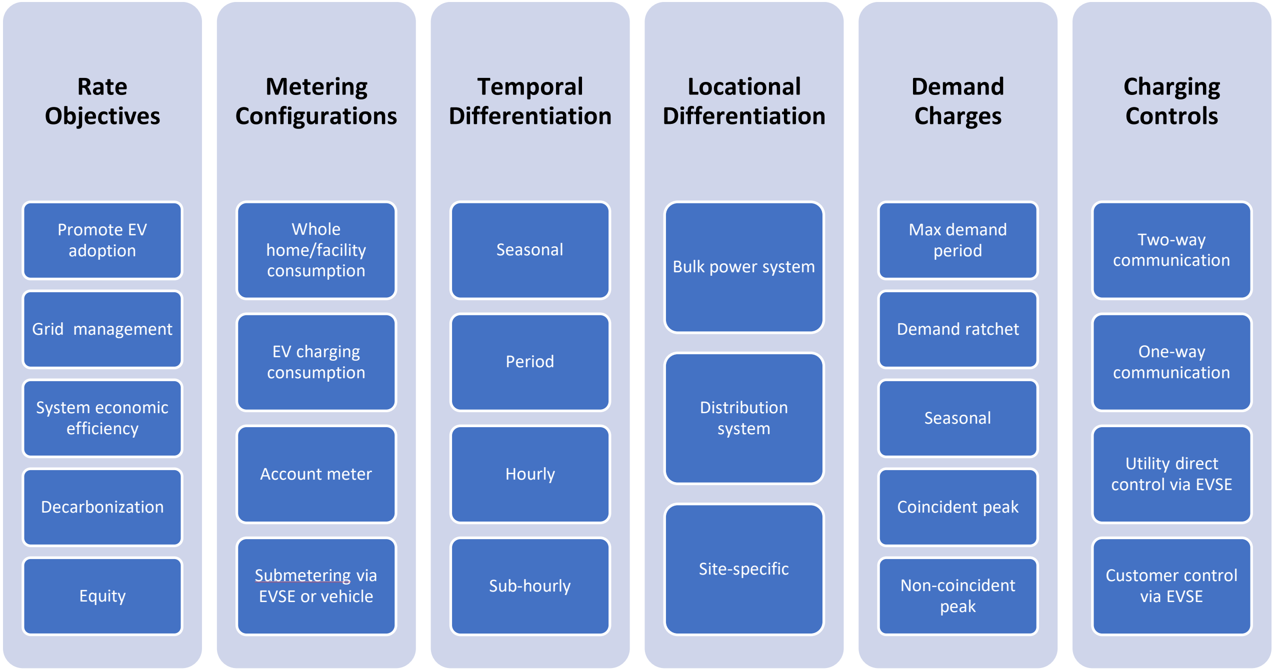

Figure 1. EV retail rate objectives and design options

EV Rate Design Objectives

Retail rates are designed based on two broad concepts. First, approved retail rates must recover a utility's costs (i.e., revenue requirement) and regulators establish just and reasonable rates based on ratemaking principles. Second, rates must satisfy certain policy and/or market objectives that can vary based on a state's distinct rules, regulations, and policies, as well as different stakeholder motivations. Although important design decisions about cost recovery, including allocation of costs to customer classes, can have profound effects on the ultimate rate levels an EV customer must pay and the success of utility business models to achieve authorized earnings levels, these aspects of rate design are not our focus.

Instead, we identify five policy-driven objectives that are used as the basis for EV retail rate design, describe their applicable rate design elements, and identify an example rate for each. While they are listed and described individually below, several objectives are interrelated and could jointly inform a utility's, regulator's, or policymaker's decisions on retail rate designs (e.g., promoting *equitable* EV adoption).

1. **Promote EV adoption** - The objective is to encourage and promote drivers to adopt EVs. Design elements produce simple and understandable rates that either enable direct comparisons to customer monthly gasoline costs and/or that result in predictable monthly EV electricity costs that yield savings relative to gasoline. An example is Austin Energy's residential *EV360* subscription rate.
2. **Grid management** - The objective is to incentivize or control EV charging in response to utility grid needs at the bulk and/or distribution levels (e.g., reduce bulk power system peak demand, support local distribution network voltage). Design elements include temporal and/or locational differentiation in rates, or demand charges that communicate utility system conditions/needs either of which may be paired with control technologies allowing the utility to directly interrupt or reschedule EV charging. An example is Tucson Electric Power's *Super Off-Peak Demand Time-of-Use EV Plan*.
3. **System economic efficiency** - The objective is to optimally charge and/or deploy EVs in a manner that minimizes long-run marginal costs. Design elements include temporal differentiation in rates that communicate marginal system costs. An example is San Diego Gas & Electric's *Power Your Drive* Pricing Plan.
4. **Decarbonization** - The objective is to charge EVs to reduce direct and indirect carbon emissions. Design elements include temporal rates that communicate a carbon signal typically based on marginal or average power system emissions. An example is Silicon Valley Clean Energy *GridShift: EV Charging* application.
5. **Equity** - The objective is to equitably share the benefits of EVs across all customers. Design elements are temporal or locational rates that do not unduly discriminate and/or more fairly apportion EV benefits to a group of customers. An example is Pacific Gas and Electric's *EV2-A* rate that is eligible for the California Alternate Rates for Energy Program (CARE) and Family Electric Rate Assistance Program (FERA).

EV Consumption Measurement and Metering Configurations

One of the primary rate design decisions is how to measure and meter EV charging consumption. The simplest and cheapest approach is to measure the customer's EV charging load combined with all other loads at the home or workplace. Any financial incentives to alter charging behavior embedded in the tariff design would be applied to all loads, not just what is used to charge the EV. Such configurations are often called "whole-house" or "whole-premise" because they encompass all of a customer's electricity consumption at the home or workplace, regardless of its source, and rely on the existing account meter. A utility could also analyze the aggregate meter data to determine if charging took place during particular periods of time and design a rate to reward customers who avoid charging then (e.g., monthly bill credit), without being concerned about the exact magnitude of the EV charging load.

Alternatively, a rate could measure only the EV charging load. In such cases, the utility has a few options for how to measure it. First, the rate could require two revenue grade meters: one to solely measure the EV charging and a second to measure the electricity consumption for all other loads. Although EVs themselves measure electricity usage, the internal meter is not typically considered revenue grade because they either do not currently meet accuracy standards and/or have not gone through the certification process, broadly speaking. Second, for a utility seeking a less expensive but still accurate metering technology for EV charging load, a dedicated submeter for the EV that sits between the main revenue grade meter and the EV supply equipment (EVSE) is an option.

For those tariffs that require a dedicated second account meter to specifically measure the EV charging load, a number of additional issues must be addressed. First, the matter of who pays for the meter must be decided. Some utilities increase the ongoing monthly customer charge or apply an up-front meter fee at the time of installation. Second, the costs associated with the installation of this dedicated meter, along with a meter socket, lever bypass, conduit and wiring of a dedicated circuit, must also be incurred and potentially recovered by the utility. In some cases, the customer is responsible for paying a licensed electrician to perform this work; but utility or state energy office financial assistance programs could be implemented to help offset some or all of these costs.

The alternative approach for specifically measuring EV load, which relies on submetering, would require a similar set of design issues to be decided while also determining what qualifies as a submeter. Currently there are several technology options being considered by utilities. First, a stand-alone revenue-grade sub-meter, similar to what is used in multi-family dwellings, could be specified in the rate. Second and as an alternative, the utility could require a submeter that is integrated into the EVSE. Third, the EVs on-board computing capability could be used by allowing an external device to be plugged into the car's on-board diagnostic port. The first two submetering technology options would incur an additional cost for installation as they require a licensed electrician. The last option would require some form of internet access (e.g., cellular, WiFi) to transmit the meter data back to utility directly or via some authorized third-party vendor.

A utility's motivation for designing its EV tariffs will be an important driver of its proposed metering configuration. If a utility is interested in promoting EV adoption or reducing barriers to make EV adoption more equitable, then it will likely opt for the simplest and least expensive metering configuration (i.e., relying on the utility's existing meter at the premise) in order to avoid adding customer costs. Notwithstanding this possible incremental submetering costs, customers may benefit by not exposing their entire consumption to a time-based rate; in these cases, low-cost submetering could be an option worth considering. However, more granular price signals sent by the utility to a customer in order to actively or passively manage EV charging in pursuit of greater economic efficiency, grid management, or decarbonization of its power system would likely require submetering, if not a dedicated second account meter. But, grid management, economic efficiency, or decarbonization goals might also be achieved by subjecting the entire customer consumption to a time-based rate.

For more information see Whited, M., A. Allison, and R. Wilson (2018). *Driving Transportation Electrification Forward in New York: Considerations for Effective Transportation Electrification and Rate Design*. Available at: http://www.synapse-energy.com/sites/default/files/NY-EV-Rate-%20Report-18-021.pdf

Temporal Differentiation in Volumetric Energy Charges

Many EV rates incorporate some form of temporal differentiation into the volumetric energy charge (cents/kWh) that can range from multi-hour periods each day to sub-hourly, as well as different rates each season (e.g., winter vs. summer).

Time-of-Use (TOU) rate designs, which are generally the most common, introduce temporal variation in volumetric energy charges during broad, fixed time periods each day with static rate levels. When first introduced over 60 years ago, TOU rates were generally designed to coincide with longer-term forward market wholesale power contracts that had two periods: a peak period, which was defined with a 16-hour window (6:00 a.m.–10:00 p.m.) on weekdays and an off-peak period covering the remaining 8 hours of the weekday and all hours on the weekend. More recently, many utilities have shortened the peak period to more accurately reflect when marginal electricity generation costs are at their highest, but have also allowed the definition of that period to change seasonally (e.g., summer vs. non-summer months). In addition, some utilities have further broken up the daytime into two sub-periods: (1) a more narrowly defined peak period often covering just the afternoon hours, and (2) a shoulder or mid-peak period that encompasses the morning and early evening hours. A handful of utilities have also broken out the overnight hours into two subperiods, with one of them having the rate set very low (e.g., super off-peak).The ratio of the peak to the off-peak volumetric energy charge can generally range from 1.2:1.0 to 4.0:1.0.

Critical Peak Pricing (CPP) and Critical Peak Rebate (CPR) introduce temporal variation in volumetric energy charges during infrequent but fixed time periods with static rate/rebate levels. Often, these rates apply only seasonally (e.g., summer), instead of year round. They are generally overlaid on top of either flat, block, or TOU rates and are designed to infrequently but dramatically elevate the volumetric energy charge (or provide a substantial volumetric energy rebate) to compel load reductions (e.g., deferred EV charging) during times of exceptionally high electricity demand or high wholesale market prices. Customers often receive between 2- and 24-hour advance notice of such events, which is communicated to them by the utility via email, text, phone, or even a dedicated web application. The ratio of the critical peak to the otherwise applicable volumetric energy charge in that period can generally range from 5.0:1.0 to 12.0:1.0.

Variable Peak Pricing (VPP) introduces temporal variation in volumetric energy charges during broad, fixed time periods with dynamic rate levels. They are a more variable version of TOU with a CPP overlay, as they can assign a different rate level during the peak period each day, depending on system and wholesale market conditions. In contrast to a standard TOU rate, the VPP design is advantageous when system conditions vary considerably from day to day. Such rates often have a seasonal component as well, where the period definition can change (e.g., summer vs. non-summer months). The ratio of the peak to the off-peak volumetric energy charge can generally range from 1.2:1.0 to 12.0:1.0, depending on the rate level applied in the peak period.

Real-Time Pricing (RTP) introduces temporal variation in volumetric energy charges during short time intervals with dynamic rate levels. They are generally designed to pass the wholesale price of electricity (or some proxy of it) directly on to customers, instead of setting the hourly rate level during a general rate case. This is overwhelmingly done presently by providing customers with volumetric energy charges that differ at the hourly level, which are usually based on day-ahead unit commitment or market outcomes (RTP-DA) but can also be derived from a weighted average of 5–15 minute dispatch or real-time market outcomes (RTP-RT). Some utilities also allocate wholesale capacity and/or ancillary service costs to some subset of the highest priced intervals each year. The most extreme form of RTP is characterized as transactive energy, where a customer provides both a demand for all grid services but also a bid to supply grid services from a portfolio of highly interactive and controllable electric loads (including EV charging load) into a highly dynamic and interactive market that produces a price signal on a sub-hourly basis (e.g., every 5-15 minutes) from a market clearing process.

A utility's motivation for designing its EV tariffs with some form of temporal differentiation will greatly inform which option is pursued. If a utility is interested in promoting economic efficiency, then more temporal differentiation is likely to be introduced into the volumetric energy charge that is highly reflective of marginal operating costs. If instead managing grid operations or decarbonization of the electric grid is a utility's main motivation, then they would likewise want to pursue more temporal differentiation but tie the energy charge closer to the state of the distribution grid or the level of carbon being produced, respectively. For motivations that focus on EV adoption or equity, it is likely that simpler rate designs with limited to no temporal differentiation would be pursued, though they are not necessarily incompatible.

For more information see Forrester, S.P and P. Cappers (2021) *Opportunities and Challenges to Capturing Distributed Battery Value via Retail Utility Rates and Programs*. Available at: https://emp.lbl.gov/publications/opportunities-and-challenges

Locational Differentiation in Volumetric Energy Charges

The engineering challenges imposed on the distribution grid from the additional load and maximum demand associated with EV charging loads differs dramatically from one location to another, which ostensibly will impose different costs on the system. Utilities could represent these different costs and grid challenges (including emissions) into the volumetric energy charge by differentiating it on a locational basis. Specifically, EV tariffs could incorporate some form of locational differentiation into the volumetric energy charge (cents/kWh) which could be applied at either the bulk power system level (e.g., pricing zone, climate zone) or at the distribution system level (e.g., substation, feeder). Or, to a lesser extent and in the context of emissions, at a site-level (e.g., home or workplace).

Presently, the majority of electric utilities in the U.S. design their retail rates for each customer class to be uniform throughout their entire service territory – meaning there is no locational differentiation in any charge applied to the utility's customers. This is largely a function of insufficient data granularity and disinterest among regulators to create location-based rates, as it makes for very complicated ratemaking. In a few instances across the U.S., the cost of producing and transmitting electricity may differ enough to warrant differentiating at the bulk-power system level. Because of this limited experience, utilities may be reluctant to introduce any additional locational differentiation in EV rate design if their objective is to promote EV adoption or to ensure equitable access to EV charging opportunities. However, several utilities are now tracking avoided costs at points on the distribution system for calculating benefits of non-wires alternatives and regulators are increasingly interested in distribution system costs. Increasing the locational differentiation of the volumetric energy charge will likely help mitigate the impacts of more EV charging load and/or signal where more flexible EV charging loads may provide the most value, which promotes system economic efficiency (i.e., reflecting differences in average or marginal costs imposed by EV charging loads at lower levels of the electrical grid) and/or managing parts of the grid that are already overloaded. In addition, a utility may want to provide a more locationally differentiated carbon signal to reflect the fact that site-based emissions can vary dramatically (e.g., EVs reduce gasoline tailpipe emissions, which can vastly improve air quality in certain areas with lots of vehicles or lots of vehicle idling).

For more information see Forrester, S.P and P. Cappers (2021) *Opportunities and Challenges to Capturing Distributed Battery Value via Retail Utility Rates and Programs*. Available at: https://emp.lbl.gov/publications/opportunities-and-challenges

Demand charge rate designs

Aside from the volumetric energy charge, a utility also can incorporate a charge into the tariff based on the customer's maximum demand of electricity (i.e., demand charge or $/kW-month). This maximum demand is measured over some period of time, typically a month, where the level of that demand can be set any time by each customer independent of other customers (i.e., non-coincident peak demand), when the bulk power or distribution system in aggregate reaches its maximum level (i.e., coincident peak demand), or when each customer's maximum demand occurs during a pre-defined set of hours (e.g., peak period) each month (i.e., billing demand). The time interval for measuring the maximum demand can range from 15-minutes to an hour. In addition, the utility could measure demand each month, independent of any previous measurements, or could maintain a level of measured demand for some period of time into the future (e.g.,12 months) in order to take a longer-term view of maximum demand (i.e., demand ratchet). Utility tariffs can also differ in the level of the charge applied to that measured demand. The demand charge ($/kW-month) may be the same all year or can vary seasonally (e.g., summer vs. non-summer months).

Since EV charging can impose considerable additional demands on the electric grid that are intermittent, demand charges are viewed by some as a very appropriate means for recovering utility costs incurred to operate a more complex and challenging grid. In addition, demand charges send an economic signal to an EV owner about the deemed cost of imposing this additional demand on the system. However, depending on their design, the demand charge can account for the majority of a customer's bill, which can be challenging if not impossible to sufficiently manage. The end result can make EV ownership or EV charging station operation significantly more expensive and changes the customer economics in terms of EV adoption. This has resulted in a lack of support for their adoption by some others in the electric industry and/or promoted the application of demand charge "holidays" or waivers for a fixed number of years to mitigate the concerns.

The electric utility industry's experience with demand charges is rich at the industrial and large commercial class level, but less so among small commercial and, especially, residential customers. More importantly, the types of loads and load profiles that were the focus of this historical experience may have limited applicability for EVs and their charging profiles. As a result, utilities focusing on EV adoption as well as energy equity may be reticent about imposing demand charges in EV rates at the residential level as well at the non-residential level because of the adverse economic impacts they can impose. In contrast, if a utility wants to promote economic efficiency, decarbonization, or grid management, then it might introduce a demand charge based on marginal costs, marginal emissions, and/or operating conditions on the grid.

For more information see U.S. Department of Energy (2021). *Voices of Experience: An EV Future - Navigating the Transition*. Available at:
https://www.smartgrid.gov/files/documents/An_EV_future_10.21.21_FINAL.pdf

EV Charging Controls

Aside from volumetric energy charges and demand charges, a utility can use control technology as a means for supporting efforts to more directly manage the charging loads from customers' EVs. Design decisions on this issue determine whether the customer must have some form of connection to the utility with which to communicate its charging status (one-way or two way) as well as whether the utility or the customer may control EV charging patterns.

The simplest design approach uses a very indirect control strategy that allows customers to retain complete control over their charging behavior while integrating financial or other interventions. The customer would leverage their EV's onboard controls or the apps provided for their vehicle to pre-program a charging strategy in response to a predefined and static price signal, without any obligation to maintain an electronic connection between the charger and the utility. However, a customer could elect to have its Level 2 or direct current (DC) fast charger receive price signals from the utility (e.g., via its charge management system) in order to more easily respond to the utility's chosen rate design. A customer would need to incur the additional equipment and installation costs for these types of chargers.

Alternatively, the utility could pursue a more direct strategy requiring that the customer grant control over their EV charging behavior to the utility, enabling the utility to manage the electricity draw of the EV when connected. The Level 2 or DC fast charger could be controlled directly by the utility or managed by a third-party that serves as an intermediary between the customer and the utility. In either case, technology that can support two-way communication between the entity providing the control and the EV is required, whose cost is likely borne by the customer. In exchange, the customer faces a lower rate (or is directly financially compensated). The level of this rate discount (or incentive payment) is often predicated on the ability of the customer to override the charging control signal - having more firm control over EV charging patterns is worth more to the utility than the alternative resulting in a deeper discount. The utility usually specifies in the rate's terms and conditions the limitations of their ability to control the customer's EV charging load.

As with the other design elements, a utility's motivations greatly influence their decision regarding a role for charging control technologies. For example, a utility that wants to more directly manage the charging patterns of its EV customers to better support grid operations is more likely to pursue a strategy that employs utility control with two way communication and limited to no ability for customer override. The same is likely true for a utility focused on deep decarbonization, as it can limit charging during times when the grid is relying on carbon-heavy generating assets and promote charging when the generating mix is heavily composed of renewable energy technologies. The additional financial incentives typically offered for utility control can improve the economics of owning and operating an EV; however, it may also result in customer dissatisfaction because it limits the customer's ability to charge their EV when they want to. As such, a utility focused on promoting EV adoption overall or more narrowly focused on promoting equity considerations may want to consider offering alternative EV rates without controls. Yet, EV rates without utility control may forgo the cost reductions from managed EV charging strategies that could put downward pressure on rates. A utility that wants to promote economic efficiency may be more likely to utilize price signals for charge management rather than using control technology.

For more information see Dayem. K, C. Mercier, and P. May-Ostendorp (2019). *Electric Vehicle Charging Control Strategies*. Available at: https://www.cooperative.com/programs-services/bts/documents/techsurveillance/surveillance-article-evse-load-control-strategies-jan-2019.pdf

Designing EV Rates

In practice, the rate objective will constrain the rate design choices. Figure 2 shows the rate design choices that are most likely to be selected for each of the five rate objectives.

EV adoption decisions are primarily driven by economic considerations and, to a lesser extent, a desire to communicate rates clearly to customers so they can make like-for-like comparisons or price their services consistently (for public charging stations). As a result, a rate objective promoting EV adoption will limit rate design choices in terms of cost and simplicity. Specifically, the rate is likely to use the customer's existing account meter and existing charging controls embedded in the EVSE to avoid incremental metering and/or control costs. In addition, rates are unlikely to introduce any additional temporal or locational differentiation, or demand charge to maintain simplicity and comparisons to current electricity bills and/or gasoline costs.

EV grid management rates are intended to minimize or avoid distribution and/or bulk power system operational impacts and associated costs. Design choices for EV grid management rates communicate distribution and/or bulk power system conditions either via price or load signals. Submetering the EV charging, either via the EVSE or a second account meter, is most likely in order to separate EV and home or facility consumption. Rates with temporal differentiation on either a period, hourly, or sub-hourly basis, as well as with event-based prices and with locational differentiation or demand charges that communicate distribution and/or bulk power system conditions are also likely to be implemented. Finally, ideally two-way communication to EV chargers with either utility or customer control can enable greater management of EV charging loads.

EV rates for system economic efficiency communicate marginal system costs to encourage charging that minimizes long-run marginal costs. EV charging will likely be submetered either via EVSE or a second account meter, because the objective is to minimize incremental cost impacts of the EV. Rates are likely to have temporal differentiation on an hourly or sub-hourly basis and/or demand charges consistent with the temporal differentiation of marginal costs. Locational differentiation in rates would also be consistent with either distribution or bulk power system marginal costs. One-way communication of marginal system costs and customer control via the EVSE is more likely to allow customers to respond to the price signal.

EV rates to achieve sectoral and/or economy-wide decarbonization are designed around marginal or average emissions rates and with differentiation consistent with the emissions type and location. Accordingly, rates are likely to require a second account meter or some form of submetering via the EVSE, in addition to two-way charging controls, to accurately target the emissions source(s). Temporal differentiation reflecting bulk power system emissions would likely result in a TOU design to reflect the relatively consistent diurnal pattern of emissions levels. Alternatively, if the focus is on site-based emissions then an RTP design would be more appropriate given the hourly variation in fossil-based operations. Demand charge design would need to align with the same level of differentiation in emissions.

Designing rates for equitable EV deployment is based on choices that limit incremental costs, many of which are paid by all ratepayers, and potential electricity bill risk and volatility. Use of the existing account meter and one-way charging controls in the EVSE can avoid incremental metering costs to the customer and/or ratepayers. Temporal differentiation is likely to be limited at most to seasonal rates or rates with broad off-peak periods to minimize significant bill increases from peak period consumption while maximizing fuel cost savings in a simple and dependable manner. Locational differentiation and demand charges are unlikely to be included in the rate design.

Rate Objective	Metering Configuration	Temporal Differentiation	Locational Differentiation	Demand Charges	Charging Controls
Promote EV adoption	Existing account meter	None, Seasonal	None, Bulk power system	None	EV charger
Grid management	Submetering, 2nd account meter	TOU, CPP/CPR, VPP, RTP (based on marginal operating conditions on the distribution grid)	Bulk power system, Distribution system	Based on marginal operating conditions on the distribution grid	Two-way communication
System economic efficiency	Submetering, 2nd account meter	RTP (based on marginal operating costs on the grid)	Bulk power system, Distribution system	Based on marginal costs	EV charger
Decarbonization	Submetering, 2nd account meter	TOU, RTP (based on marginal or average emission levels)	Bulk power system, Distribution system, Site-specific emission levels	Based on marginal or average emission levels	Two-way communication
Equity	Existing account meter	Seasonal, TOU	None	None	EV charger

Figure 2. EV rate objective and constrained design choices

Of course, care should be taken in designing EV rates especially to achieve multiple objectives and avoid unintended consequences. For example, EV submetering is more important for rates that encourage specific EV charging behavior and is less important for promoting EV adoption or may create additional costs that pose a barrier to low-income customers. Also, demand charges can be designed consistent with cost causation and economic principles, but may hinder early EV adoption and/or fast charging.

There are a number of non-rate elements that can further achieve EV-related objectives. First, EV rebates and other financial incentives (e.g., tax credits) reduce the upfront purchase costs and encourage EV adoption. Programs that improve the customer economics for EVs can be targeted to low- and moderate-income customers, as well as programs that encourage adoption of used EVs, and further equity objectives. Second, utilities may invest in charging networks, including public and home charging. A more robust charging network may address customer concerns about sufficient charging stations and utility investments could be targeted in multi-family dwellings and other locations that lack third-party charging networks, which is particularly important for ensuring equitable access to EV charging. Utilities may also invest in EV chargers with direct control and/or communication capabilities to better manage system demand. Third, utility investments to appropriately size or modernize the distribution system can further enable new EV charging loads, especially from medium- and heavy-duty EVs.

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