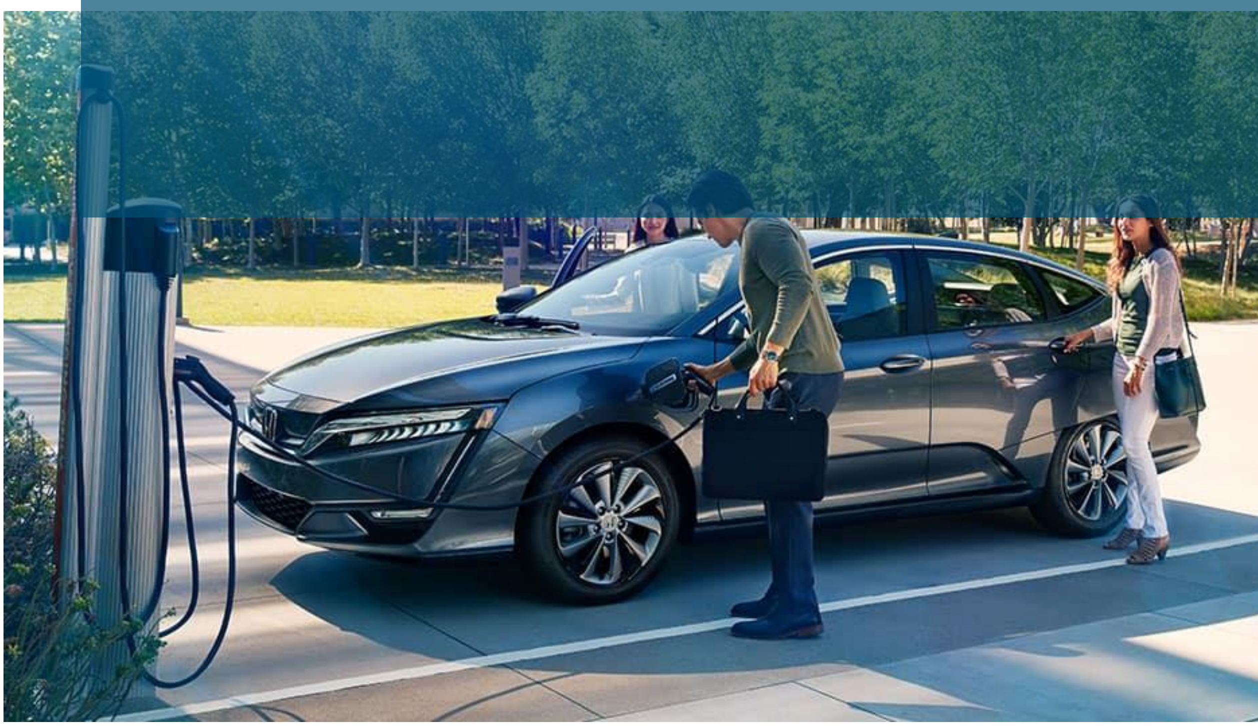
Rate Designs Harnessing Vehicle Grid Integration Technology

May 2021

Novel Rate Designs for Aggregator Enabled Smart Charging



Energy+Environmental Economics

Contents

Figures 3

Tables 4

1. Executive Summary 5

2. Setting the baseline: Deteriming VGI Value Under Existing Rates 9

2.1. Methodology and Inputs 9

2.2. Results 11

2.2.1. The Benefits Under Flat Rates 11

2.2.2. Switching to TOU rates 12

2.2.3. Charging profile analysis 13

2.3. Summary 15

3. Increasing Value with VGI Aggregator Rate Designs 16

3.1. Aggregator VGI Scenario 16

3.2. Tariff design methodology 17

3.3. Charging Load Impacts of VGI Rates 19

3.3.1. Baseline TOU Rate 19

3.3.2. Dynamic Energy Rate 20

3.3.3. Dynamic Rate with Aggregated Non-coincident Demand Charge 20

3.3.4. Dynamic Rate with TOU Aggregated Non-coincident Demand Charges 21

3.3.5. Dynamic Rate with Distribution Load Management 21

3.4. System Cost Impacts 22

3.4.1. Residential Charging 22

3.4.2. Workplace Charging 24

3.4.3. System Value of VGI and Dynamic Tariff Designs 26

3.5. Translating the value of VGI rates to business models 27

3.5.1. Increased Benefits 27

3.5.2. Shared Bill Savings 27

3.6. Summary 28

4. Conclusions 29

5. References 31

Figures

Figure 1 - Charging load under current rates and best available TOU rates with VGI. TOU rates shift charging to low-cost hours but results in significant increases in peak load. 5

Figure 2 - Aggregator tariff scenario: utilities bill aggregators for total fleet charging load and aggregators in turn bill drivers for managing their charging. 6

Figure 3 - Annual average system cost to serve a MWh of residential charging load. 7

Figure 4 - Core functions of the EVGrid model 9

Figure 5. Average lifetime costs and benefits of personal LDV adoption under the IEPR EV adoption forecast and current rates. 11

Figure 6. EV adoption forecasts from IEPR and Bloomberg 12

Figure 7. Net benefits comparison of personal LDV adoption under current and best rates 13

Figure 8. Aggregated 2025 charging load during a summer week under current rates 13

Figure 9. Aggregated 2025 charging load during a summer week under best rates 14

Figure 10. A summer week of charging load under current and best rates and overlayed with utility avoided costs (right hand axis). 14

Figure 11. Schematic for the aggregator tariff scenario 17

Figure 12 - Tariff design approach 18

Figure 13 - Charging profile under the Baseline TOU rate 19

Figure 14 - Charging profile under the Dynamic Energy Rate 20

Figure 15 - Charging profile under the Dynamic Rate with Aggregated Demand Charge 21

Figure 16 - Charging profile under the Dynamic Rate with TOU Aggregated Demand Charges 21

Figure 17 - Charging profile under the Dynamic Rate with Distribution Load Management 22

Figure 18. Annual average system cost to serve a MWh of residential charging load 23

Figure 19. Charger capacity and potential demand for charging 24

Figure 20. Annual average system cost to serve a MWh of workplace charging load 25

Figure 21 - Potential bill savings for different driver types 28

Tables

Table 1 – Four of the more promising tariffs explored in this study. 7

Table 2. Cost and benefit components for the three cost tests used in the CBA analysis 10

Table 3. Flat and current TOU rates used in the CBA to represent drivers in PG&E's service territory. 10

Table 4. NPV of net benefits for vehicles adopted in the PG&E territory from 2020 to 2030 12

1. Executive Summary

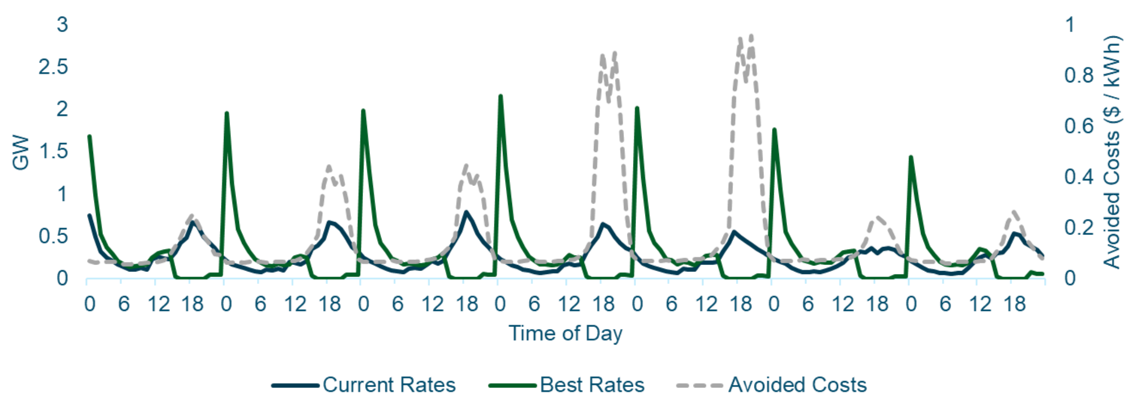
As Electric Vehicle (EV) penetration gathers momentum in the coming decade charging loads pose a potential major challenge for utilities without proper planning and management. Vehicle-Grid Integration (VGI) technologies strive to smooth the transition and convert EVs from a potential grid strain to a valuable new grid resource. Customer bill management has been identified as one of the most promising near term use cases for VGI and involves managing vehicle charging to minimize a customers' retail tariff. Tariffs will be the primary or only interface with the electric grid for the vast majority of EV drivers in the near term. Time-of-Use (TOU) rates are by far the most common EV rate implemented by utilities, but do not fully realize potential VGI benefits. Advanced metering, declining technology and communication costs, and rapid commercialization of smart charging technologies make advanced rate designs a viable and broadly available VGI pathway. This paper presents new tariff designs that harness active VGI technology and EV charging aggregators to unlock greater value than the most advanced tariffs today.

Setting the baseline: VGI with Time-Of-Use tariffs can unlock significant value for drivers and the grid.

Initial analysis determined the baseline grid value that VGI could generate under existing tariffs. The costs and benefits of adopting an EV over an equivalent combustion engine vehicle were calculated focusing on the Pacific Gas and Electric (PG&E) service territory where 2.5 million EVs are forecasted to be on the road by 2030. Results show that using VGI technology with PG&Es best available time-Of-Use (TOU) retail tariffs enable drivers to reduce their lifetime charging costs by $3,165 on average versus charging under a basic flat rate with PG&E ratepayers still benefitting by $5,009 per EV.

A review of the hourly charging load optimized against PG&Es flat and TOU tariffs reveals that the on-peak TOU period aligns well with PG&E's high grid costs hours resulting in large reductions in grid costs. However, since TOU tariffs apply the same price signal to all EVs for managing charging, it creates a risk of secondary peaks occurring that could stress the distribution system. To avoid secondary peaks charging must be coordinated across the EV fleet rather than sending the same price signal to every EV.

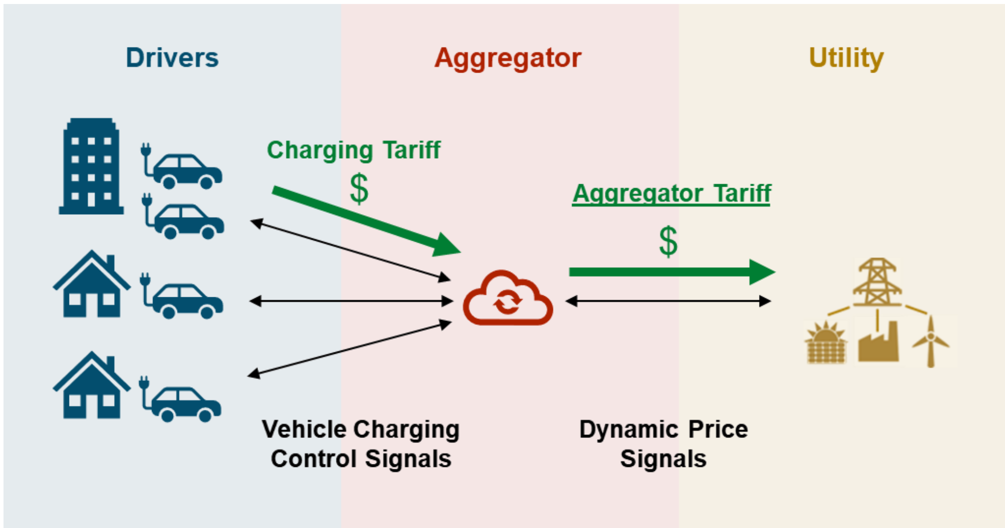
Figure 1 - Charging load under current rates and best available TOU rates with VGI. TOU rates shift charging to low-cost hours but results in significant increases in peak load.



Incentivizing coordinated EV charging through aggregator tariffs

With the value of VGI established under existing tariffs, new designs were proposed that could unlock greater grid benefits with a focus on incentivizing coordinated charging across groups of EVs in a utility's service territory. One solution for effectively coordinating charging for large groups of EVs is through the use of an aggregator. This paper proposes a new concept of an *aggregator tariff* which involves a utility billing an aggregator for combined charging of all EV load. The aggregator in turn can choose to bill drivers at some simple flat rate or monthly fee in exchange for control of their EV charging.

Figure 2 - Aggregator tariff scenario: utilities bill aggregators for total fleet charging load and aggregators in turn bill drivers for managing their charging.



The aggregator tariff represents a potential win-win-win for utilities customer and aggregators compared to traditional tariffs:

1. Utilities can design more complex and dynamic tariffs than typical residential tariffs which more accurately reflect grid costs. They can also outsource the capability to manage individual EV loads if needed.
2. Drivers have access to simple low-cost charging without having to worry about peak periods or charging timers.
3. Aggregators are rewarded for enrolling drivers on more dynamic tariffs and dynamically managing charging loads to benefit the grid.

Aggregator Tariff Designs Process

To simplify the tariff design process rates were set such that they recovered the *exact same revenue as the baseline TOU rate*, therefore ensuring no cost shift to other ratepayers. The difference between each tariff was therefore simply how much they reduced grid costs through incentivizing new charging behavior. The 2020 CPUC Avoided Costs were used to quantify the grid costs and benefits of each design.

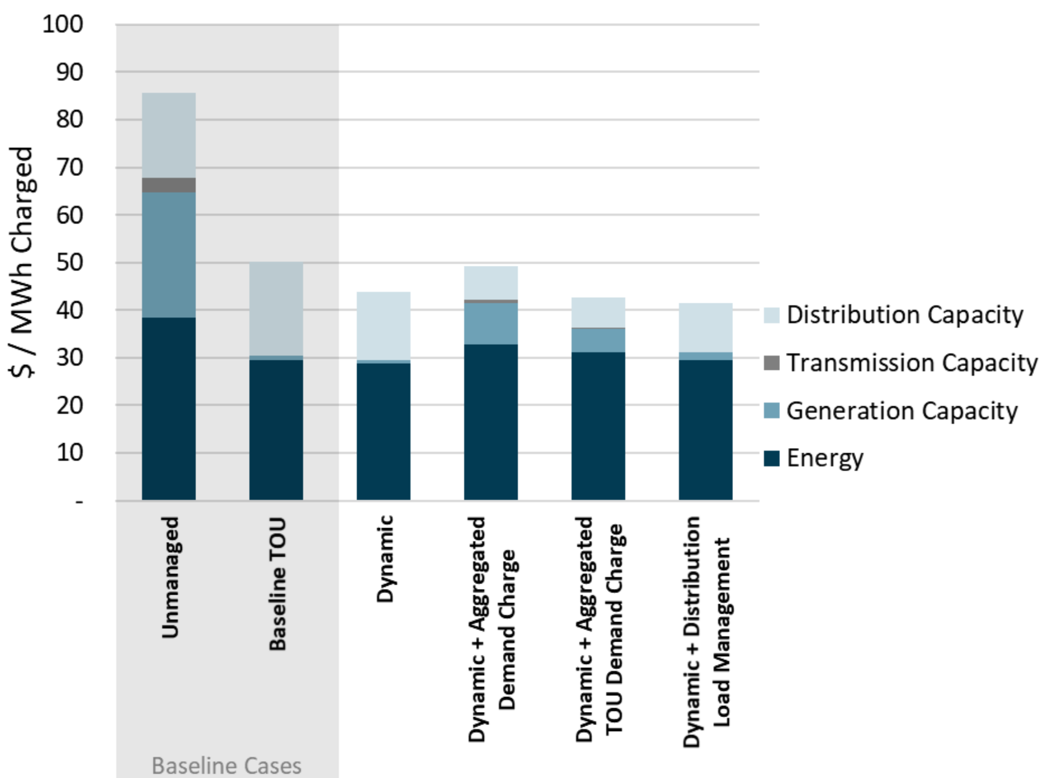
Four of the more promising VGI aggregator rate designs explored are presented below. Each tariff had a meter and energy charge and then may also include a non-coincident demand-based charge like a demand subscription or monthly demand charge which applies to the charging load of the *full aggregation*. A demand charge coincident with the distribution system feeder load was also explored where the aggregator would be billed for aggregate charging peak load coincident with the distribution system peak load.

Table 1 – Four of the more promising tariffs explored in this study.

Tariff Name	Meter Charge?	Dynamic Energy Charge Components	Non-Coincident Demand Charge?	Distribution Coincident Demand Charge?
Dynamic	yes	Energy LMP, GHG Adder, Generation Capacity, Transmission Deferral, Distribution Deferral	No	No
Dynamic Rate + Aggregated Demand Charge	yes		All hours	No
Dynamic Rate + Aggregated TOU Demand Charges	yes		All hours & Peak hours	No
Dynamic Rate + Distribution Load Management	yes		No	Yes

Results show the dynamic rate with distribution load management was the most effective tariff at reducing grid costs, generating an additional 17% in system cost savings beyond the baseline TOU tariff. The dynamic rate alone shifts charging away from peak hours effectively but has highly variable secondary peaks that could impose costs on the secondary distribution system. Adding a flat non-coincident demand charge that applies to the aggregate charging load creates a strong signal to flatten charging load but results in load being shifted back into on peak hours relative to the dynamic rate alone, increasing grid costs. Grid costs to serve charging load under each tariff are shown below.

Figure 3 - Annual average system cost to serve a MWh of residential charging load.



Advanced rate designs could generate an additional $41 per EV per year versus the best available TOU rate today with $15 per year arising from load management at the workplace and $26 per year arising from residential charging load management. Results highlight that full VGI load management under the best available TOU rates today already captures nearly all available energy, transmission, and generation capacity value. However, the new tariffs presented here are highly effective at incentivizing smoother load shapes which have much less potential to increase distribution system costs.

These results are highly dependent on the avoided cost inputs and were only explored for PG&Es service territory. More granular modelling of system costs both temporally and geographically could uncover additional value particularly for certain areas of the distribution system and represents a logical next step for further analysis.

Enrolling an unresponsive driver into an VGI aggregation rate could generate up to $373 per EV per year.

Better rate design alone could unlock up to $41 per EV per year but aggregators can also ensure consistent price response compared to if drivers were to manage charging themselves using charging timers. Based on literature review we assume 65% of drivers are likely to manage their charging load themselves. Aggregators can offer a simper charging experience to drivers, if they can target and enroll drivers who would not otherwise change their charging behavior in response to tariffs, then system cost savings could be up to *$373 per EV per year*.

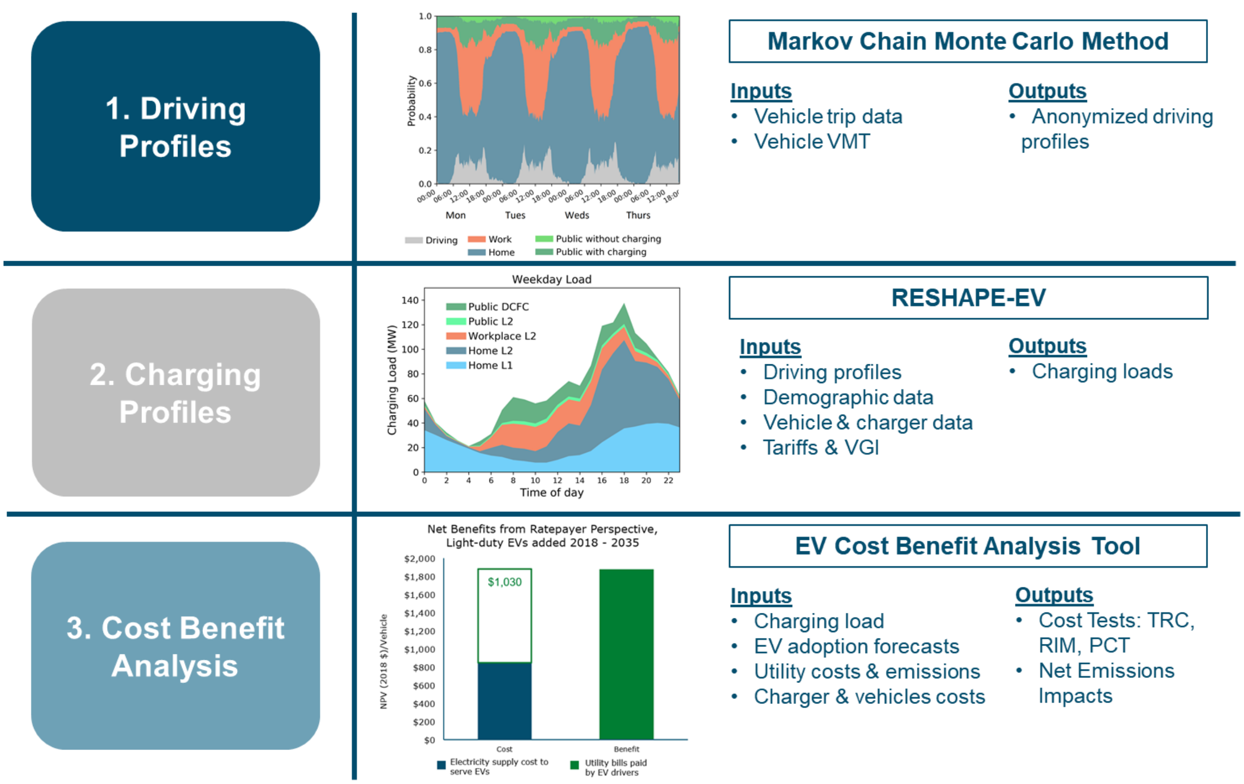
2. Setting the baseline: Deteriming VGI Value Under Existing Rates

This section lays the foundation for advanced rate designs by first investigating the grid impacts of managed charging technology using existing retail rates. The analysis focuses on the PG&E service territory and the potential benefits that new EV load can bring to drivers, utility ratepayers, and California under two scenarios: PG&Es basic flat rates and PG&E's EV TOU rates. Results show that using managed charging with the best available existing TOU rates could half driver electric bills and increase societal benefits by 14%. However, utility ratepayers would see less substantial benefits if using VGI with TOU rates compared to basic flat rates, due to the revenue drop from drivers optimizing their charging and paying lower electric bills. The section highlights how TOU rates are a major improvement on flat rate structures but have limitations which the advanced rate designs introduced in section 3 seek to address.

2.1. Methodology and Inputs

To conduct this analysis E3 employed the EVGrid model which ingests driving data, vehicle and charger characteristics, utility system costs, emission data, and rate structures to calculate the costs and benefits of vehicle electrification. The tool has been used in multiple regulatory filings, program evaluations, and other studies to study a wide variety of vehicle types (E3, 2021). This analysis focuses on the system costs and utility bill impacts of personal Light Duty Vehicles (LDVs). The tool performs 3 main tasks, generating driving profiles, simulating EV charging, and performing cost-benefit analysis, as shown in Figure 4.

Figure 4 - Core functions of the EVGrid model



EVGrid outputs three different cost tests established by the CPUC that offer different perspectives on costs, benefits, and net savings from adoption of EVs. The Total Resource Cost (TRC) test, Participant Cost Test (PCT), and Ratepayer Impact Measure (RIM) offer regional, EV driver, and ratepayer perspectives, respectively, on costs and benefits over the lifetime of an EV. These costs and benefits are calculated over the lifetime of each vehicle adopted between

2020 and 2030 and converted to a net present value. The Cost Benefit Analysis Tool Components included in each cost test are depicted in Table 2 below.

Table 2. Cost and benefit components for the three cost tests used in the CBA analysis

Cost/Benefit Component	Total Resource Cost (TRC)	Participant Cost Test (PCT)	Ratepayer Impact Measure (RIM)
Incremental EV cost	Cost	Cost	
Federal EV tax credit	Benefit	Benefit	
EV O&M savings	Benefit	Benefit	
Fuel savings	Benefit	Benefit	
Electricity Supply Costs for EV charging	Cost		Cost
Charging infrastructure cost	Cost	Cost	
Electricity Bill for EV charging		Cost	Benefit

Vehicle trip data are a key input for the first step of EVGrid to generate anonymized driving profiles. Vehicle and driver trip data from the National Household Travel Survey (NHTS) and vehicle miles traveled (VMT) are used to develop anonymized 15-minute driving profiles for thousands of drivers using E3's Markov Chain Monte Carlo Method.

How EV charging profiles align with grid costs and electric tariffs ultimately determine the costs and benefits of EVs and the potential for VGI technology to generate additional value. The model utilizes the driving profiles generated in the Markov Chain Monte Carlo Method as well as demographic data, vehicle and charger characteristics, and rates to produce normalized load shapes which are then aggregated to generate a representative hourly charging load shape.

The adoption forecast is another crucial component to determine overall benefits. E3 used an EV adoption forecast from the California Energy Commission (CEC)'s Integrated Energy Policy Report (IEPR) and ran a sensitivity using an EV adoption forecast from Bloomberg New Energy Finance's 2019 EV Outlook.

The analysis focused only on PG&E's service territory and compared costs and benefits under two sets of rates, "Current" rates which are the most simplistic rate structures PG&E offers (usually a flat rate for all hours) and "Best" rates which are the most dynamic rates available in each customer class (most often TOU rates). Table 3 shows the PG&E residential and commercial rates used in the analysis.

Table 3. Flat and current TOU rates used in the CBA to represent drivers in PG&E's service territory.

	Current	Description	Best	Description
Res	E-1	• Fixed daily charge • Flat energy rates	EV-2A-TOU-NEM	• Fixed charge • TOU energy rates
Com	A-10	• Fixed daily charge • Flat summer and winter energy rates • Flat summer and winter demand rates	C-EV	• Subscription charge • TOU energy rates

System cost impacts of charging profiles are evaluated using the 2020 CPUC Avoided Costs. Avoided costs are a forecasted sum of system energy, generation, transmission, distribution and GHG cost components.[1]

[1] For further description the 2020 CPUC Avoided Cost Calculator is available at: https://www.cpuc.ca.gov/General.aspx?id=5267

Drivers simulated in EV Grid are representative of different use cases selected by the California Joint Agency VGI Working Group. As part of the CPUC DRIVE Rulemaking (R. 18-12-006), the VGI Working Group has identified use cases in which VGI can provide value. The use cases analyzed in this CBA overlap with use cases identified by the VGI Working Group and include:

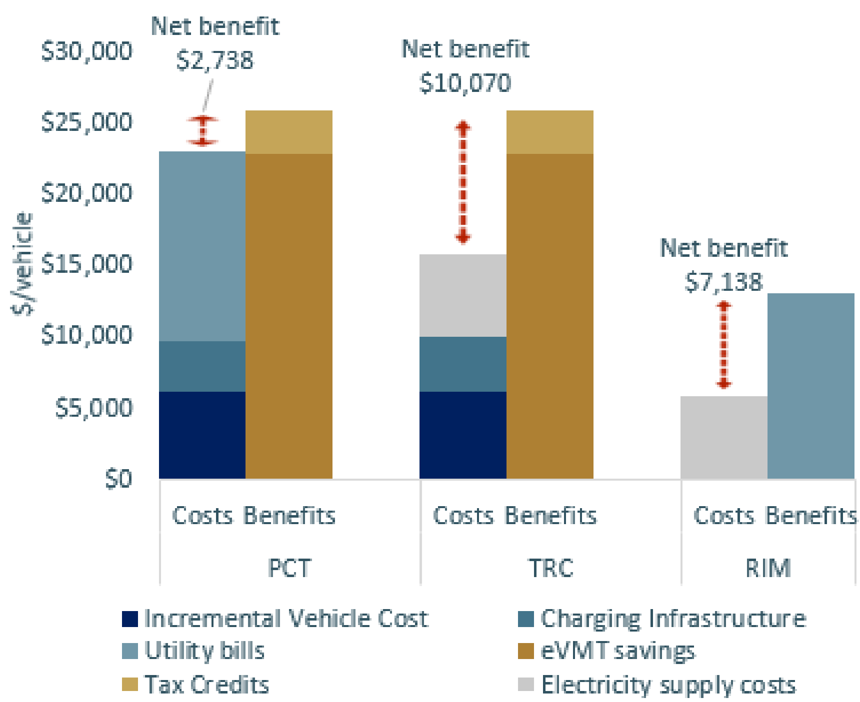
- Residential single-family home (SFH) L1 (1.1) and Multi-Unit Dwelling (MUD) L1 (413.1)
- Residential SFH L2 (1.2) and MUD L2 (413.2)
- Workplace L2 (818)

2.2. Results

2.2.1. The Benefits Under Flat Rates

Results for electrification of LDVs under current rates show that adopting an electric personal LDV rather than a traditional ICE vehicle is beneficial for drivers, California, and PG&E ratepayers on average over the 2020 to 2030 period. Figure 5 below which shows the Net Present Value (NPV) of costs and benefits on a per vehicle basis.

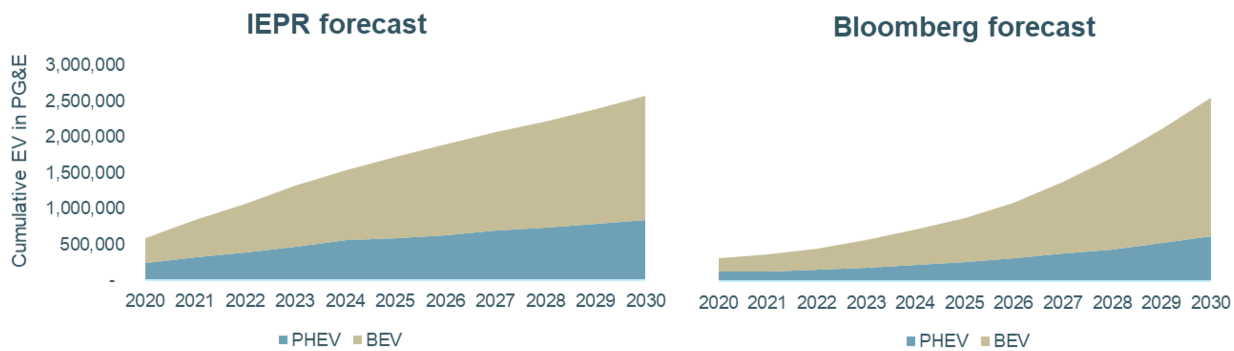
Figure 5. Average lifetime costs and benefits of personal LDV adoption under the IEPR EV adoption forecast and current rates.



This result is based on EV drivers charging with VGI technology under the basic flat rates offered by PG&E. A large component of benefits for drivers and for California are eVMT savings, which include avoided gasoline and O&M costs that would otherwise be incurred during a conventional vehicle's lifetime. Although drivers who adopt EVs see net savings, the benefits are modest due to high electricity rates. Under basic flat rate structures ratepayers see a large average lifetime net benefit of $7,138 for each vehicle adopted between 2020 to 2030 as the additional revenue the utility gains from higher electricity bills significantly outweighs the cost to serve that load. Aggregating these per vehicle lifetime results for all vehicles adopted between 2020 and 2030 across PG&E's territory shows that electrification of personal LDVs will bring billions of net benefits. Drivers will gain a total of $10.5 billion, PG&E ratepayers will gain $8.9 billion, and California would gain over $20 billion from EV adoption in PG&E territory.

E3 ran a sensitivity of the CBA under current rates to use the BNEF EV adoption forecast instead of the IEPR forecast. The two EV adoption forecasts are shown in Figure 6 below.

Figure 6. EV adoption forecasts from IEPR and Bloomberg



While both forecasts reach 2.5 million cumulative EVs in PG&E's service territory by 2030, the main difference is that the IEPR forecast features earlier adoption of EVs. The earlier adoption of EVs in the IEPR forecast allows drivers and the state to receive higher federal tax benefits, since the tax benefits expire by the mid-2020s. Additionally, drivers are able to capture greater eVMT savings through earlier adoption. The comparison of the NPV of benefits under the IEPR and Bloomberg forecasts are shown in Table 4 below.

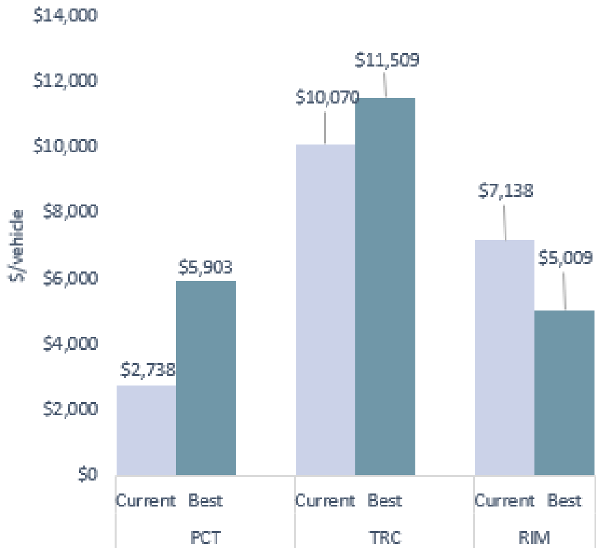
Table 4. NPV of net benefits for vehicles adopted in the PG&E territory from 2020 to 2030

$ 2020 B	PCT	TRC	RIM
IEPR	10.5	20.4	8.9
Bloomberg	9.4	17.4	8.5

2.2.2. Switching to TOU rates

To understand the impact of rate design on these results a CBA was also conducted for EV drivers on PG&E's best residential and commercial TOU rates currently available. These TOU rates include either a fixed charge or subscription charge for residential and commercial customers, respectively. A comparison of net benefits captured by drivers, the state, and ratepayers under PG&E's current and best rates is shown in Figure 7 below.

Figure 7. Net benefits comparison of personal LDV adoption under current and best rates

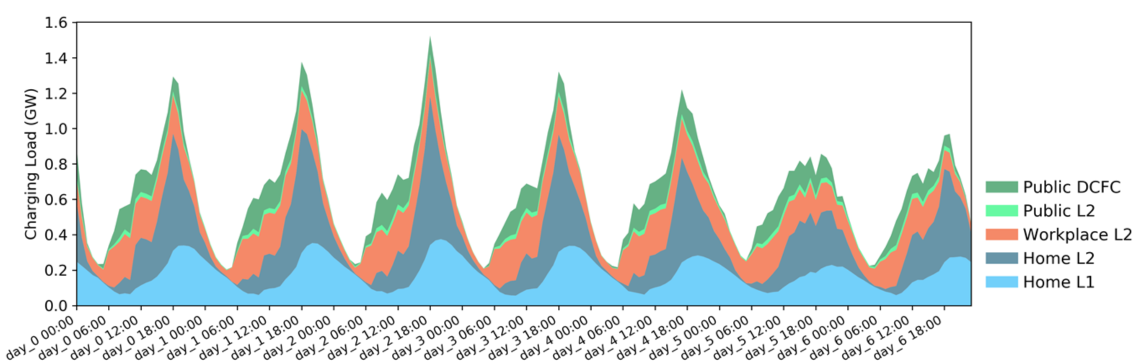


Under the TOU rates, EV drivers and the state see increases in net benefits compared to the current rates because of reduced electricity bills and electricity supply costs, respectively. Drivers see a 116% increase in net savings over the lifetime of their EV while the state sees a 14% increase. Ratepayers see a 30% decrease from drivers switching from basic flat rates to TOU rates because the drivers have lower electricity bills and this reduction exceeds the reduction in electricity supply cost, but net benefit to ratepayers of EV adoption remain very large.

2.2.3. Charging profile analysis

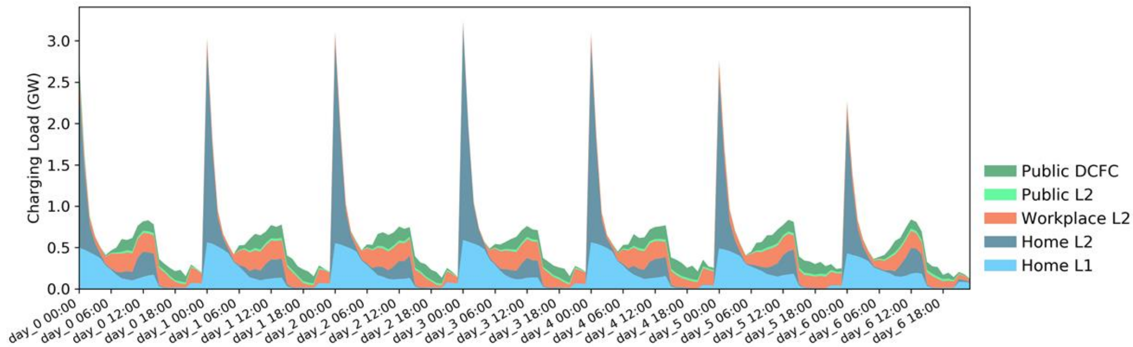
Charge management based on current and best rates produce drastically different charging profiles. As a flat rate with only a workplace demand charge, the current rates result in charging that is largely dependent on the when drivers arrive at locations with access to charging. For example, as can be seen in Figure 8 below, peak charging occurs when most drivers arrive home from work around 6 pm. The charging profile is aggregated across 1.54 million drivers per the IEPR EV adoption forecast in 2025, resulting in a peak load of 1.52 GW. For comparison, under the Bloomberg EV adoption forecast, the number of EVs on the road in 2025 is around 790,000 vehicles resulting in a peak load of 0.78 GW.

Figure 8. Aggregated 2025 charging load during a summer week under current rates



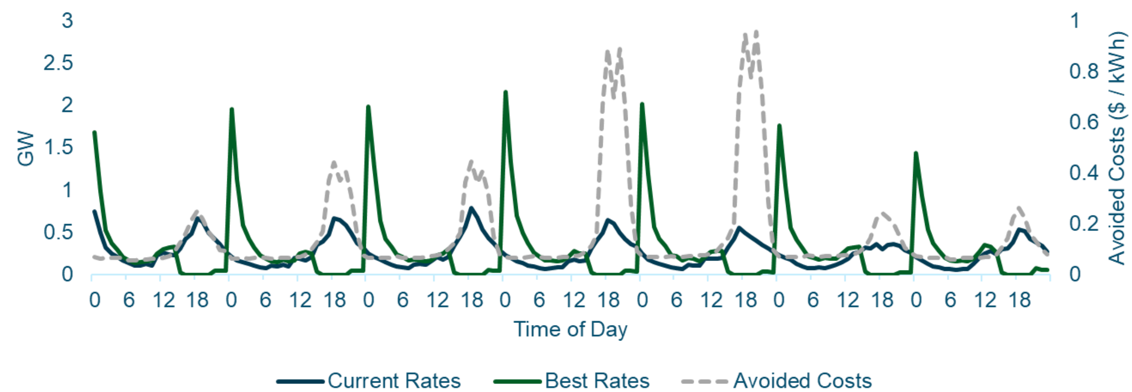
Charging under best rates results in a drastically different charging profile, as can be seen below.

Figure 9. Aggregated 2025 charging load during a summer week under best rates



When VGI is employed using the best available TOU rates as the only price signal, most vehicles begin residential charging exactly when the TOU period ends at 10 pm, resulting in sharp spikes in charging load of 3.31 GW, over twice as high as the peak load under current rates. As a reminder, this simulation was carried out assuming 100% driver participation to get a bookend estimate of potential load and system impacts. Figure 9 is therefore showing the impact when all 1.54 million drivers simulated are use VGI technology to respond to the exact same price signal. To understand the impact of these charging profiles on electric system costs, we show the hourly avoided costs and the two charging profiles for a summer week in Figure 10.

Figure 10. A summer week of charging load under current and best rates and overlayed with utility avoided costs (right hand axis).



Charging load peaks around 6pm under the current rates which coincides almost exactly with peak system costs. The peak period for PG&E best rates is well correlated with system costs, allowing charge management against best rates to incur significantly lower system costs. However, the magnitude of the load spikes that occur at the end of peak TOU periods could fundamentally shift high avoided costs hours or increase the distribution system upgrade cost.[2] Therefore, without alternative rates or incentives, using VGI with the best available rates as the only price signal might render higher distribution costs and lower net benefits in TRC and RIM cost tests than shown in Figure 7. It should be noted that as electrification and new DERs reshapes demand conventional TOU may become less effective than it is today. Varying and extending TOU peak periods can help, but there may be limits to what customers will tolerate.

[2] These impacts are not fully captured by the avoided cost calculator since the model is based on a price taker assumption, however they are addressed in section 7 on more advanced rate design.

An aggregator or a more advanced rate design could help distribute charging over the off-peak period while still meeting driver charging needs. Advanced rates could also further reduce system costs by shifting charge load to hours with lower system cost and offer drivers more charging flexibility. System peaks do not always last the full length of TOU periods; therefore, advanced rates could potentially free up more hours for drivers to charge without incurring significant system cost increases.

2.3. Summary

The cost-benefit analysis of personal LDV electrification in PG&E territory shows that EV adoption will bring billions in net benefits to drivers, ratepayers, and California. Over the lifetime of all EVs adopted between 2020 and 2030, drivers will gain a total of $10.5 billion, PG&E ratepayers will gain $8.9 billion, and California would gain over $20 billion, in present value. If all drivers were to move from flat rates to the best available time-varying rates PG&E offers and have their charging fully managed, then drivers see a 116% increase in their net benefits from lower charging bills. Net benefits for California also increase by 14% as system costs decline from driver charging profiles changing in response to the new time-varying rates. However, ratepayers would see a slight decrease in net benefits by 30% as revenue from rates drops faster than system cost reductions. Overall though, ratepayers would still benefit substantially from EV adoption.

If all drivers are managed using the exact same price signal, however, large secondary peak loads can occur immediately after the peak TOU period ends. These secondary peaks may not shift transmission or generation capacity hours but could have implications further to the customer end of the distribution system which are not well captured in a price taker framework. Furthermore, more dynamic rate structures could also limit the periods when charging is disincentivized enabling more flexibility for drivers. The next section investigates more advanced rate designs that could capture achieve these goals.

3. Increasing Value with VGI Aggregator Rate Designs

To quantitatively explore some of the more cutting-edge rate design concepts discussed so far, E3 utilized its modelling toolkit to simulate the impact of active VGI technology on charging load and system costs under different dynamic price signals. The objective of the analysis was to propose new tariff designs that make better use of active VGI technology to unlock greater grid value.

3.1. Aggregator VGI Scenario

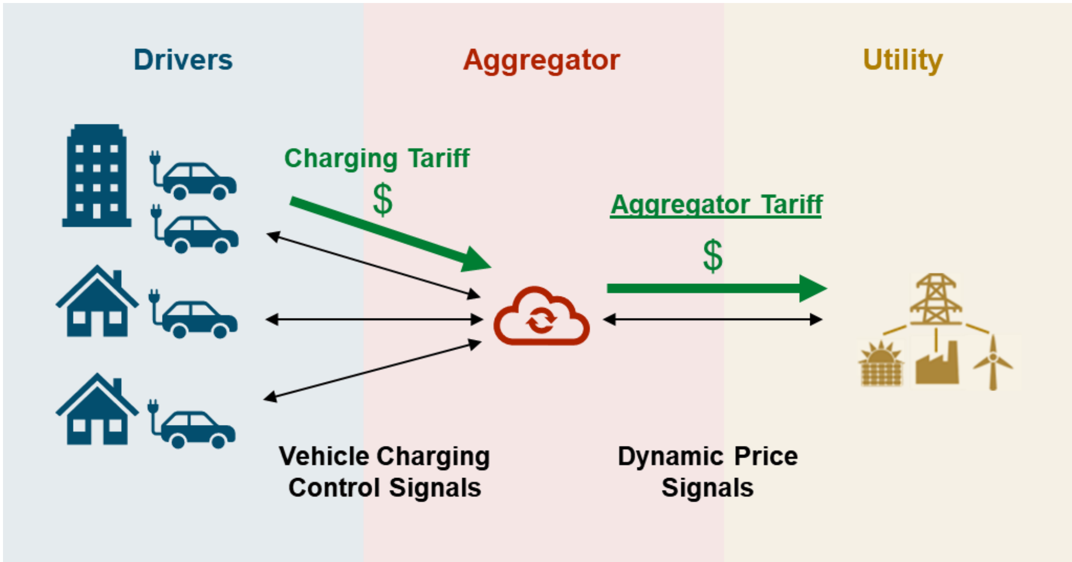
E3 chose to focus on VGI tariff design for EV aggregators that perform active managed charging for large groups of EVs. There are many advantages of allowing aggregators to manage EV charging across a large group of vehicles such as economies of scale and scope, reduced uncertainty, competition and innovation, and reduced complexity for utilities (Burger, Chaves-Ávila, Batlle, & Pérez-Arriaga, 2016). The aggregator role could be filled by the OEM, the utility, or a third party and accomplished with a range of VGI technologies. This analysis is technology and party agnostic; it does not explore the benefits and drawbacks of who performs the service and with what technology. Any 3rd party aggregators would likely need to be qualified and approved by FERC or state agencies before being privy to sensitive data such as granular distribution system loads and costs.[3]

In the scenario presented here an EV aggregator manages charging for a group of several thousand chargers at residential and workplace locations within a distribution planning area. The aggregator is billed by the utility for the aggregated charging load according to the aggregator tariff set by the utility. Drivers set their desired state of charge and departure time when they arrive at a managed charging location and the aggregator controls charging within this window to ensure the target state of charge is reached before the driver departs. Data on each vehicle's State of Charge (SOC), the drivers' desired departure time, and the drivers' desired state of charge on departure therefore needs to be passed to the aggregator to control charging. This scenario assumes that the appropriate communication technology is installed to enable two-way communication between the driver, vehicle, and the aggregator and also the aggregator and the utility for active charging control over all vehicles.

The aggregator attempts to minimize its electric bill from the utility whilst ensuring drivers charging needs are met. The aggregator tariff set by the utility therefore guides how the aggregator manages the charging of each vehicle in the aggregation. In turn aggregators can charge enrolled drivers some simple flat cost for all charging or a monthly subscription service. The driver pricing is discussed further in section 3.5 while the subsequent sections focus purely on the utility – aggregator tariff design and what value different designs can generate for the utility.

[3] Similar to requirements for accessing market price data through the Open Access Same Time Information System (OASIS) (CAISO, 2021).

Figure 11. Schematic for the aggregator tariff scenario



The aggregator tariff represents a potential win-win-win for utilities customer and aggregators compared to traditional tariffs:

1. Utilities can design more complex and dynamic tariffs than typical residential tariffs which more accurately reflect grid costs. They can also outsource the capability to manage individual EV loads if needed.
2. Drivers have access to simple low-cost charging without having to worry about peak periods or charging timers.
3. Aggregators are rewarded for enrolling drivers on more dynamic tariffs and dynamically managing charging loads to benefit the grid.

This study looks at work and residential charging locations since this represents the largest opportunity for VGI to generate value with personal LDVs. Current data and future modelling studies demonstrate around 10% of charging occurs in public, of which 8% of that is through fast charging where charging speed is critical leaving little remote for shifting load. (Wood, 2020; Engel, Hensley, Knupfer, & Shadev, 2018)

3.2. Tariff design methodology

The tariffs investigated build on the VGI rate design principles described in E3's prior work (Garnett, Cutter, & Nieto, 2020). To simplify the rate design approach and avoid complex revenue requirement modelling, all tariffs were designed to be revenue neutral compared to existing TOU tariffs thereby ensuring no additional cost shift to other utility customers. The results from section 2, in which VGI was simulated under existing tariffs, determine the baseline revenue collected by PG&E and subsequent aggregator tariff designs could vary structurally but would need to collect the same revenue as this baseline.

These tariffs are illustrative designs and may include a customer meter charge, demand charge, or employ a volumetric adder to ensure costs are recovered to match the original TOU rate. We do not explore each option in detail here, but there are many approaches to design VGI rates to collect embedded costs and ensure full recovery of the utility revenue requirement. These options could be applied to any of the rate designs described in this paper. Options include:

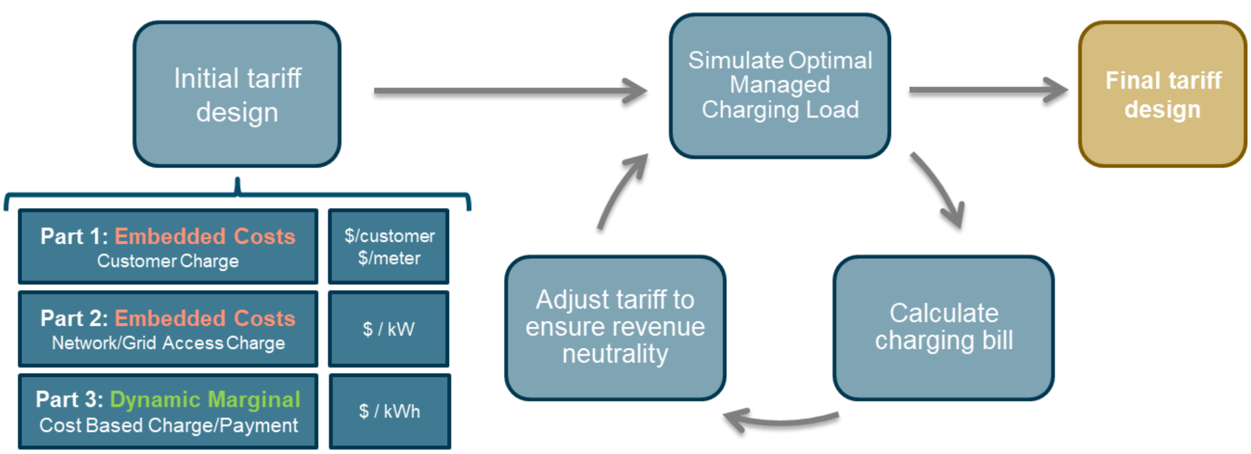
+ **Customer Charge:** $/Month customer or meter charge

- **Size Based Customer Charge**: a $/Month customer charge based on total monthly or annual energy consumption. This provides continued incentive for energy efficiency.
- **Demand or Subscription Charge**: $/kW charge for individual customer connected load.

The goal of the tariff design process was therefore to recover the *same revenue*, but with *lower system costs* which is the source of value of the new rate design. This approach illustrates that it is possible to design a VGI rate that both reduces total utility costs and does not shift costs to other customers. We do not suggest that this necessarily be a requirement. Indeed, if a VGI rate reduces utility costs, lower revenues would keep other ratepayers indifferent. There are also many possible rationales to *not* require revenue neutrality but to set rates to encourage additional EV charging (Garnett, Cutter, & Nieto, 2020). This analysis should be viewed only as a starting point; further analysis can suggest rate designs under which utility ratepayers and EV drivers can both realize benefits while also promoting EV and VGI adoption.

To design the tariffs the 2020 CPUC avoided costs were used to help determine the size of various components. The hourly dynamic charge is first set using the marginal energy and greenhouse gas adder components of the avoided costs. The actual tariffs could include the day ahead or real time locational marginal price to add further temporal and geographic granularity and therefore unlock additional benefits, but only hourly avoided costs are used for this study. A capacity adder of around $0.20/kWh is then assigned to specific peak hours to recover generation and transmission capacity costs. A base volumetric adder that applies to all hours is used to recover non-bypassable and other charges. Depending on the tariff other initial values are set for other tariff components. The initial tariff is then used to manage EV charging load in the EV Grid model resulting in a new charging load shape and a new charging bill based on the initial tariff. The cost recovery components of the tariff are then adjusted to ensure revenue neutrality and if needed the new load simulated again to arrive at a final tariff design.

Figure 12 - Tariff design approach



Described below are the baseline TOU tariff and four of the most promising tariff designs explored in this analysis:

- **Baseline TOU Rate:** Current TOU rate that is well aligned with avoided costs (these are PG&E's EV-2A-TOU tariff for homes and C-EV tariff for workplaces). This is the baseline against which VGI rates will be compared.

- **Dynamic Energy Rate:** Dynamic, hourly energy charge which could be the day ahead energy locational marginal price (LMP) with adders for peak system and distribution capacity hours. Includes a monthly customer charge.
- **Dynamic Rate with Aggregated Non-coincident Demand Charge:** a 3-part rate with a customer charge, a non-coincident customer demand charge and dynamic energy charge
- **Dynamic Rate with Aggregated TOU Non-coincident Demand Charge:** a variation on the 3-part rate with a higher on-peak and lower off-peak non-coincident demand charge
- **Dynamic Rate with Distribution Load Management:** a dynamic rate with aggregated, coincident peak load management in place of non-coincident demand charges. Aggregated load is minimized during coincident peak system and distribution load hours, maximized during renewable overgeneration hours, and limited to a subscribed level per EV during other hours.

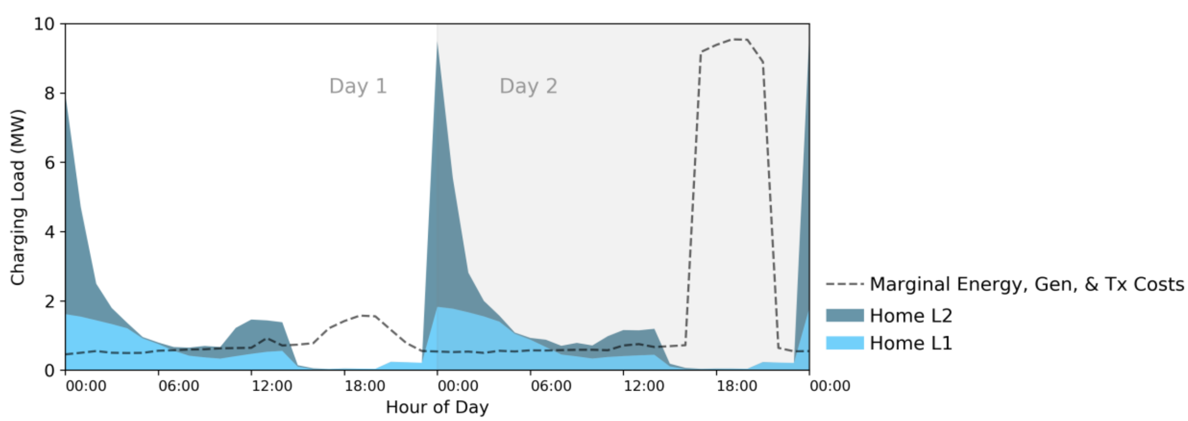
3.3. Charging Load Impacts of VGI Rates

Before exploring the impact that these new rate designs have on system costs, we first observe how each rate reshapes charging load when all vehicles are being managed by a single VGI aggregator. Optimal charging behavior under each tariff above was simulated for a 5000-vehicle aggregation in a distribution planning area and the system cost impacts of serving these new load shapes was calculated. To simplify this analysis only charging in 2025 was simulated and the same the driving and charging inputs described in section 2.1 were used. Note that under these scenarios the amount of energy consumed at home and work is the same, only the timing of the charging varies.

3.3.1. Baseline TOU Rate

Each of the advanced VGI rates described below are compared against the baseline TOU rate described in section 2.2.2 (PG&E's EV-2A-TOU tariff for residential and the C-EV tariff for workplaces). It is important to note in this case we still assume active VGI bill management technology is used to manage the charging of all vehicles in the aggregation. There is therefore 100% participation and price responsiveness which is much higher than the driver participation and responsiveness if passive VGI was implemented that relying on EV charging timers or driver charging behavior (Smart Electric Power Alliance, 2019). The charging profile under this 100% participation scenario is shown below, along with the hourly marginal costs (dashed line).

Figure 13 - Charging profile under the Baseline TOU rate

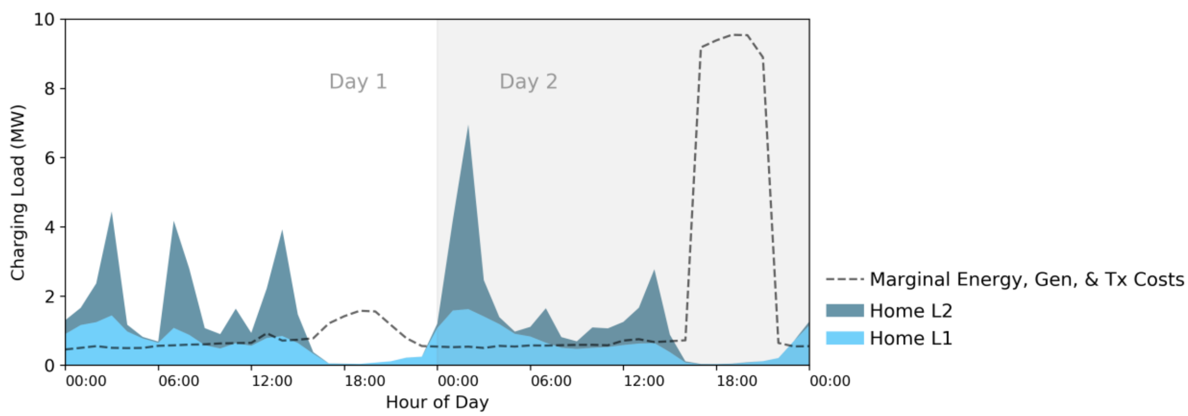


The TOU rate successfully shifts most charging out of the on-peak period. However, absent additional management, it has the risk of creating a large secondary peak at the beginning of the off-peak period, which in this case occurs around midnight.

3.3.2. Dynamic Energy Rate

This dynamic volumetric charge is tied to the CAISO day-ahead energy price, which for modelling purposes is represented by the energy component of the 2020 CPUC avoided costs. Price adders are included during system peak and distribution peak hours, based on the distribution load across the entire distribution planning area. This rate does not include any demand charges and embedded costs are recovered though a base adder to the volumetric energy rate and a monthly customer charge. Under this design the aggregator would apply the same charging signal to all vehicles in the aggregation.

Figure 14 - Charging profile under the Dynamic Energy Rate



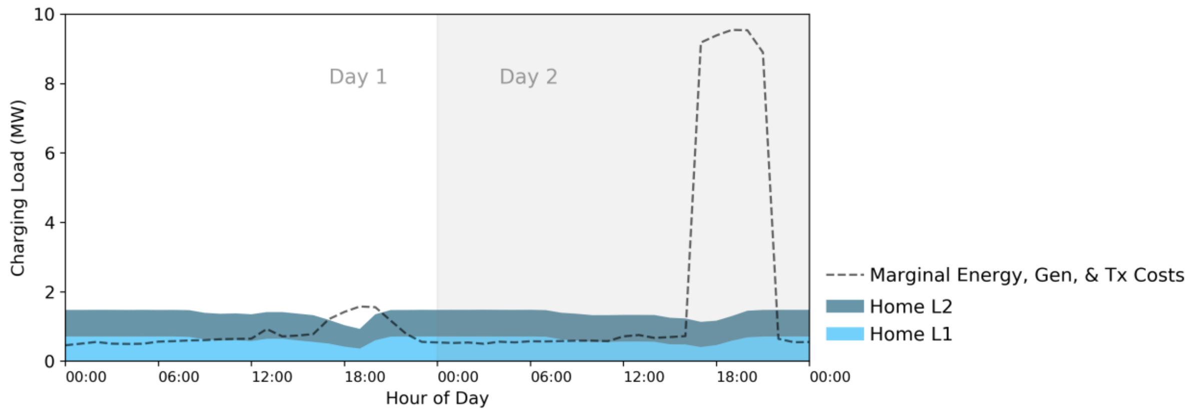
The dynamic energy rate successfully moves all charging off-peak, but results in highly variable secondary peaks as the same price signal is given to all customers in the aggregation. All charging is therefore shifted to hours with the lowest dynamic signal.

Note that under this design, additional distribution capacity adders could be included to recover costs that occur further along the distribution system right down to the secondary feeder. While this would likely lead to greater reduction in distribution costs it would also entail having unique dynamic energy signals for smaller groups of EVs within the aggregation.

3.3.3. Dynamic Rate with Aggregated Non-coincident Demand Charge

The second rate tested is a standard 3-part rate. It includes the dynamic energy rate described above, a monthly customer charge, and a monthly $/kW demand charge that applies to the aggregated load (both for residential and for commercial customers). The traditional, all-hours, non-coincident demand charge applies to the peak of the aggregate EV charging. This type of 3-part rate is commonly proposed as a more economically efficient advanced rate design. However, in this case, demand charge in this design applies not to individual drivers but to the full aggregation of EVs. The aggregator would take on the responsibility of managing the charging of individual vehicles to minimize aggregate demand.

Figure 15 - Charging profile under the Dynamic Rate with Aggregated Demand Charge

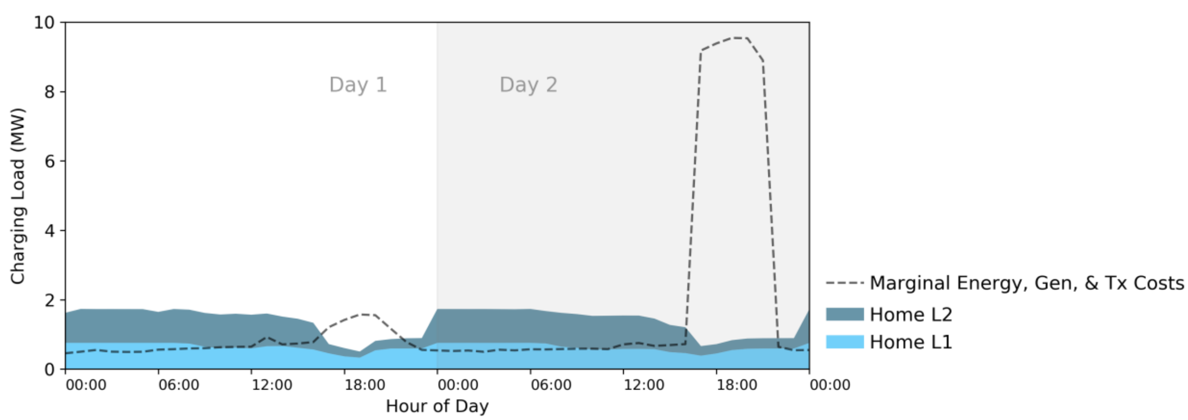


As shown in the charging profile, this rate mitigates the secondary peaks that arise with the TOU and for dynamic rates. However, the demand charge is such a strong economic incentive that it encourages the aggregator to move more charging into on-peak periods to keep the peak load as low as possible. This also severely lowers the incentive for the aggregator to take advantage of low energy prices and overgeneration.

3.3.4. Dynamic Rate with TOU Aggregated Non-coincident Demand Charges

The third VGI rate is also a 3-part rate, but with TOU demand charges in place of a single all-hours demand charge. The TOU demand charge attempts to mitigate the shift of charging into the on-peak period while the off-peak demand charge limits the secondary peaks. As above, the non-coincident demand charge applies to aggregate EV charging peak but is charged separately for the on-peak and off-peak period. As compared to the all-hours demand charge above, less charging occurs on-peak. Even with a lower, off-peak demand charge, some on-peak charging still occurs, as there is still a strong incentive to flatten charging loads.

Figure 16 - Charging profile under the Dynamic Rate with TOU Aggregated Demand Charges

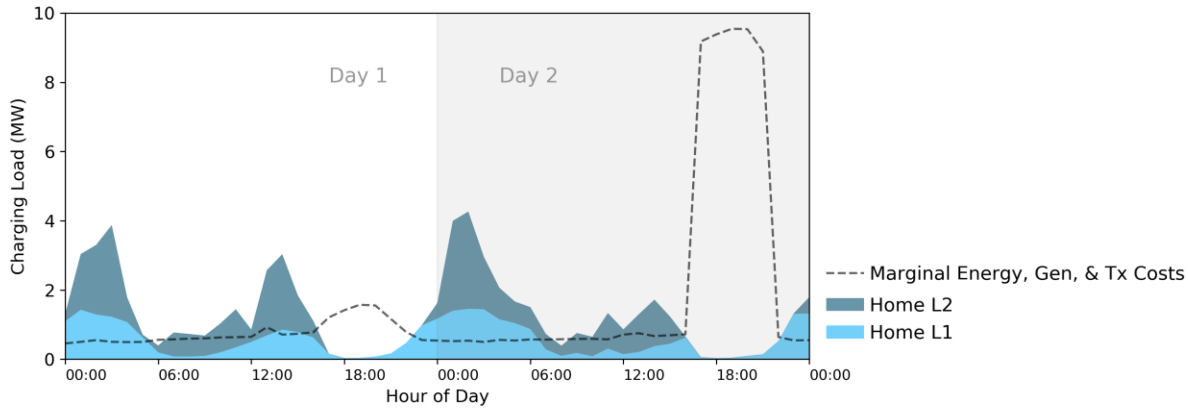


3.3.5. Dynamic Rate with Distribution Load Management

Our final rate option is a dynamic energy rate with distribution load management, with a coincident in place of a non-coincident demand charge. The demand charge limits EV charging only when it would cause an increase in total distribution system peak load. This approach limits on-peak charging, avoids secondary peaks that exceed system capacity in the off-peak hours, but allows maximum charging with distribution capacity is available. Like the energy charges, the utility would provide a day-ahead signal for hours in which EV charging must be limited the following day. Note that for the two illustrative days shown, the dynamic energy rate alone results in four hours with aggregate

EV charging load equal to or greater than 4 MW, which could potentially cause a secondary peak in excess of distribution system capacity. The dynamic rate with distribution load management keeps aggregate EV charging load at or below 4 MW, and the charging occur only when there is available capacity on the distribution system.

Figure 17 - Charging profile under the Dynamic Rate with Distribution Load Management



This rate option combines the best features of the prior rate designs tested. During peak hours, charging load is managed to be as load as feasible, while still meeting individual customer driving needs. However, outside of peak hours the demand charge incentive is not so strong that it inhibits charging flexibility to maximize the use of excess solar generation and low-priced energy. Furthermore, more distribution costs can be avoided with local load management.

In this scenario the demand charge applied to the distribution substation peak load. However, with advances in distributed energy resource management systems (DERMS), communications, and smart charging technology, it is possible to manage load even further down on the distribution system at load at the circuit and service level. Ideally the aggregator could manage peak loads right down to the final line transformer or secondary distribution line, providing additional benefits for the utility distribution system.

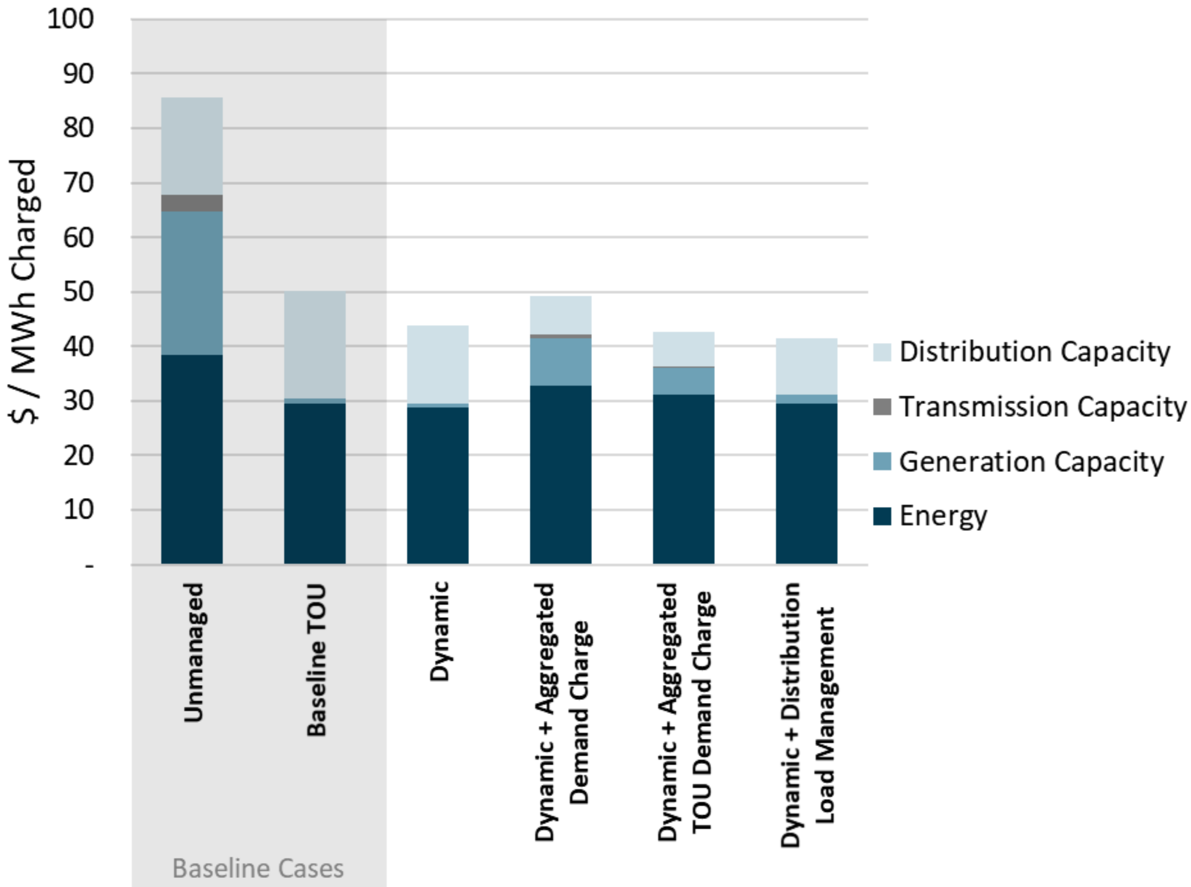
3.4. System Cost Impacts

The cost to serve charging load is calculated using the 2020 CPUC hourly avoided costs (Energy and Environmental Economics, 2020) and the resulting charging load shapes under each tariff. This section presents system costs for servicing both residential charging and workplace charging loads.

3.4.1. Residential Charging

For each rate design described in section 3.3 the $/MWh cost to deliver energy for residential EV charging load is shown in Figure 18. Recall that under these different rate scenarios the driving patterns, number of EVs, and amount of energy charged during each charging session is exactly the same, the only variation is in the timing of charging whilst each EV is plugged in at home. Recall also that each VGI rate is designed such that the revenue collected by the utility is the same as that for the TOU rate. For unmanaged charging, the average cost of delivered electricity is $85/MWh. The baseline TOU rate lowers that cost to $50/MWh. Each of the advanced VGI rate designs reduce the system costs further still.

Figure 18. Annual average system cost to serve a MWh of residential charging load



As described in section 2.2, the peak periods of the baseline TOU rate (EV-2A-TOU) are well aligned with energy, generation and transmission costs so there is limited room for further reduction in these costs. However, the large surge in charging immediately after the TOU period ends creates a secondary distribution peak pushing up distribution system costs, particularly further down the distribution system, that could be mitigated. Figure 18 also includes the system costs to serve an unmanaged charging profile to demonstrate the large cost reductions that are achieved from managing the charging of a driver that would otherwise be unresponsive to rates.

If the aggregator was charged a dynamic energy signal then system costs are reduced by 13% relative to the baseline, this distribution costs are still significant as all EVs are managed using the exact same charging signal so large secondary peaks still occur when the dynamic signal is lowest.

Including a demand charge lowers distribution costs substantially but incentivizes the aggregator to move charging load to higher cost hours for energy, generation and transmission resulting in just a 2% reduction in system costs relative to the baseline. If TOU demand charges are included the distribution costs are almost the same, but other system costs decrease so cost savings increase to 12%.

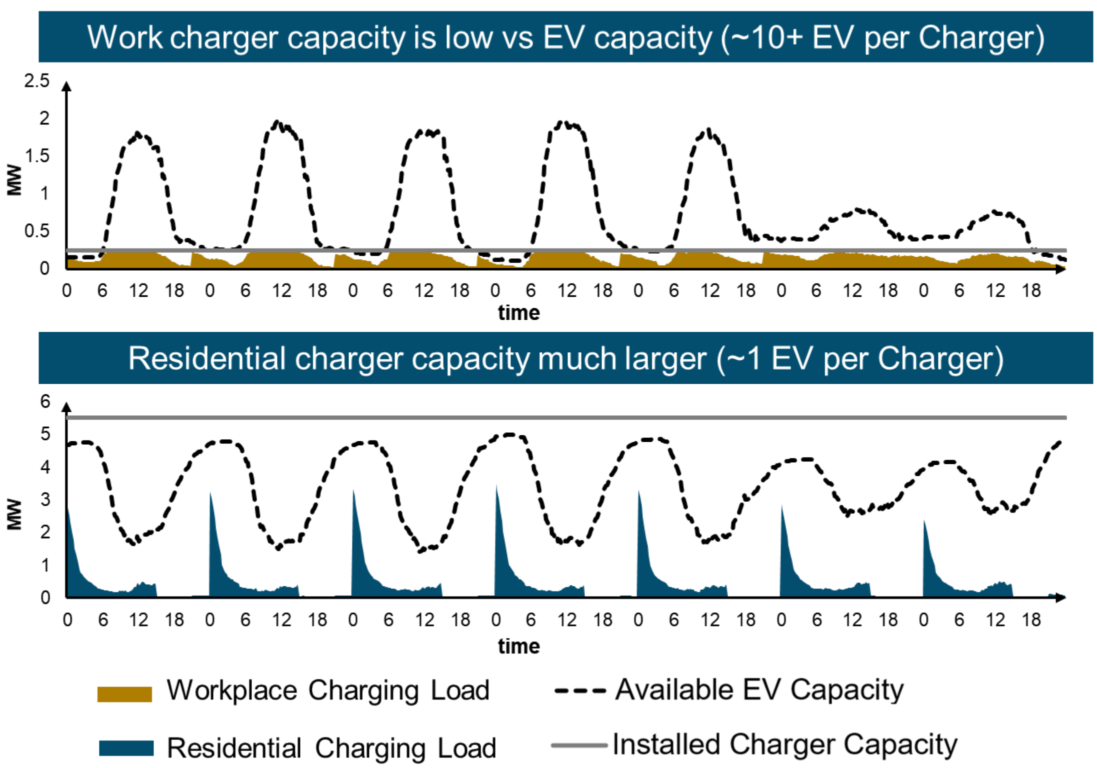
Finally, the distribution system management rate allows for large distribution cost savings but retains enough charging flexibility that the energy, generation, and transmission costs are almost the same as the dynamic rate, leading to the greatest cost saving of 17%.

3.4.2. Workplace Charging

Before exploring the system cost impacts of the different workplace VGI tariff designs, it is important to discuss the impact that installed charging capacity has on load flexibility. At high EV penetrations installed charging capacity is likely to be significantly more constrained at workplaces relative to the potential demand. Based on driving pattern data, projected EV adoption, and optimal charger installation projections, there will be around 10 – 20 EVs at workplaces for every charger installed in 2025.[4] The number of vehicles at workplaces wanting to charge during the day is therefore likely to lead to very high utilization of workplace charging infrastructure.

Today workplace charger utilization is low in part because of much lower EV penetration but also other practical reasons such as drivers not moving their vehicles immediately when finished charging to allow another vehicle to charge (Whaling & Harty, 2019). We assume these practical issues are resolved by 2025 through deployment of multiarmed charging infrastructure or other solutions. Consequently, our simulations show that workplace charging load levels off quickly once all chargers are occupied and stays constant through most of the working day as vehicles are charged in turn. Sharp charging peaks are therefore much less of an issue at workplaces, but the downside is the potential for charging flexibility is also much lower. Figure 19 shows the maximum charging level for the aggregation of EVs at work and at home as the level grey line. The available battery capacity for EV charging is shown as the dotted line. At work the EV charging is limited by EV charger capacity, limiting the flexibility to shift charging. At residential locations, the opposite is true; charging is limited by available battery capacity and there is significant flexibility to shift charging.

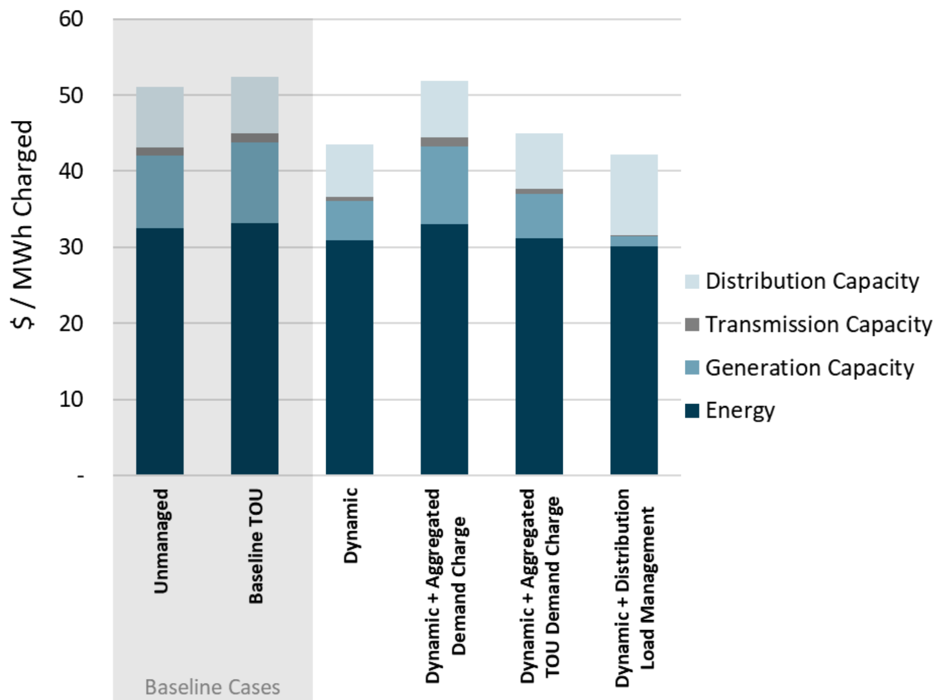
Figure 19. Charger capacity and potential demand for charging



[4] Calculated from the EVI-Pro Lite tool for California in 2025 (NREL, 2018)

Given this, we see the variation in distribution costs for workplace charging does not vary substantially across the different tariff designs, as shown in Figure 20 below.

Figure 20. Annual average system cost to serve a MWh of workplace charging load



Firstly, it is important to note that the baseline workplace rate (PG&E's C-EV tariff) already includes a subscription charge which provides a strong incentive to minimize peak load. Consequently, the baseline rate incurs relatively large capacity costs in comparison to the residential baseline TOU rate since more load is shifted to high system cost hours to reduce the non-coincident peak and the overall cost to serve load is slightly higher at $52/MWh. Secondly, note that the unmanaged charging case here actually shows slightly lower system costs compared to the baseline, this is due to the charging infrastructure limitations described previously which physically limit peak load and lead to very high charger utilization. On average

As with the residential tariffs all the dynamic rates tested show cost savings relative to the baseline. The trend of workplace cost savings among the tariffs with demand charges show a very similar pattern residential, with the single non-coincident demand charge being the highest cost, while the coincident demand charge is the lowest. However, unlike the residential scenarios, here the Dynamic rate shows the most substantial cost savings with a 17% reduction relative to the C-EV rate which translates to around $15 per EV per year. The limited charging capacity naturally prevents sharp peaks in load that were seen with the residential Dynamic rate scenario. The effect of adding a demand charges is much less significant at workplaces; peak load is reduced somewhat but this added benefit is outweighed by the cost of additional load being moved into peak energy, generation, and transmission hours.

This study did not explore scenarios with greater levels of workplace charging infrastructure. Adding workplace chargers could unlock greater load flexibility but requires significant upfront cost which may be shared by utilities may if they provide commercial charging rebates. As the capacity of workplace charging increases so does the potential for sharper charging peaks that could stress the distribution system if loads are unmanaged. Therefore, adding charging capacity also increases the need for good rate design; if charging capacity is low enough even completely unmanaged charging is unlikely to create substantial problems for utilities and the case for VGI rates is much weaker from a system cost perspective. This tradeoff is an interesting avenue for further study but is beyond the scope of this analysis.

3.4.3. System Value of VGI and Dynamic Tariff Designs

Our analysis calculates that the system cost value of an aggregator managing a group of EVs under more advanced VGI rate design compared to management under existing TOU rates, to be $41 per EV per year. This assumes an average residential consumption of around 2,900 kWh per year and an average workplace consumption (including those drivers than do not have residential charging) of 1,700 kWh per year. For residential charging, $26 per EV per year in system cost reductions could be generated if the aggregator switched from the existing EV-2A-TOU tariff to the Dynamic Rate with Distribution Load Management. For workplace charging, $15 per EV per year in system cost reductions could be generated if the aggregator switched from the existing C-EV tariff to the Dynamic Energy Rate option. Since a workplace charger is serving 10 – 20 EVs in our analysis, the per charger system cost savings are therefore roughly $150 - $300 per charger per year and as mentioned increasing the amount of charging infrastructure at work could increase the total potential benefit further.

The 2020 CPUC Avoided Costs are a crucial input into the system cost calculation. While these avoided costs have a long history of use in various regulatory proceedings and analysis in California there are several limitations that could result in value being excluded from the above results. For a variety of policy and methodological reasons there is less energy price volatility and curtailment hours than often exhibited in the actual wholesale market. Some of the avoided cost streams also have relatively coarse geographic granularity and this analysis may be overlooking high value pockets: distribution costs are calculated for each climate zone with all other costs being calculated at the service territory level. The avoided costs also represent one potential future for the evolution of the electric system and are updated each year to align with new policy and technology developments.

The distribution capacity avoided costs include diversified peak load driven costs for distribution substations, transformers and feeder level, but do not include connected load driven costs at the circuit or service level. Distribution costs are allocated to distribution peak load hours, which differ for each of 16 climate zones. This approach does not account for the risk of creating secondary distribution peaks with high penetrations of EVs. For illustrative purposes in this study, we take a simplified approach of allocating 70% of the distribution capacity avoided costs to the on-peak period and allocate 30% to secondary peaks that may occur in the off-peak period. This has the effect of imposing some costs on VGI rates that create higher secondary peaks, such as the baseline TOU rate and the dynamic energy rate alone. Further study would be needed to fully assess distribution cost impacts and avoided costs for different VGI rate options. Even so, this approach illustrates how more advanced VGI rate designs could provide additional distribution value to motivate further investigation. Using an updated set of avoided cost streams with that address the above issues represents an excellent next step for analyses.

The above calculation assumes as a baseline that *all* EV charging is responding to a TOU rate, which is unlikely in the real world. A significant portion of EV charging is not occurring on TOU rates or drivers are simply unresponsive to rates entirely. An aggregator that successfully engages a higher percentage of drivers in managed charging would provide even greater benefits. We therefore analyze a scenario assuming only 65% of drivers are enrolled in and respond to TOU rates based on consumer surveys performed by SEPA (Smart Electric Power Alliance, 2019). Using 65% driver price responsiveness as a baseline we estimate the system cost value the aggregator could provide to be $68 per EV per year on average. The system benefit of enrolling a driver not managing their charging into an aggregated VGI program would be higher still at $133 per EV per year.

3.5. Translating the value of VGI rates to business models

The previous section calculated the system cost value of different aggregator VGI tariffs, finding that $68 per EV per year in system cost value could be generated from a driver with average price responsiveness. However, realizing this value requires investment and deployment of advanced VGI technologies including communications, software, admin, and technical support. The previous sections focused on how the utility would bill the aggregator to deliver electricity for charging, this section briefly describes pathways for a viable aggregator business model.

Recall that the VGI rates proposed were structured so the utility would collect the same revenue as the baseline TOU rate. Instead of the system cost savings of $68 per EV per year benefiting the utility alone, the value could be shared, with some portion of those savings being awarded to the aggregator, potentially through a lower aggregator tariff or a direct payment from the utility to the aggregator. For example, if the utility were to pass 70% of the benefits to the aggregator this would result in a payment of ~$4.00 per EV per month. At scale, with sufficiently inexpensive technology and communication costs, it is possible to envision a sustainable aggregator business model, but greater revenue potential may be necessary to attract the necessary investment in the near term.

3.5.1. Increased Benefits

This analysis of VGI is presented to encourage further investigation into viable tariff designs, and such investigation could well find additional system benefits. As described above, day-ahead energy price volatility and hours of curtailment are higher in today's market than they are in the 2020 CPUC avoided costs. Real-time price volatility is higher still. This could provide additional energy benefits for advanced VGI rates. Furthermore, given EVs can respond to highly dynamic price signals, if the tariff were to incorporate 5-minute price signals utilities could use EVs instead purchasing power from the real time energy market during periods of undersupply. in We have also discussed above how additional distribution benefits could potentially be realized with increasingly localized load management. With further thought and investigation, it may well be possible to show higher net system benefits than in this initial analysis.

Another potential benefit is LCFS credits, which have not been explored. Aggregators could increase the LCFS credits generated by demonstrating charging with renewable energy or claim credits for customers otherwise unable to monetize the credits themselves.

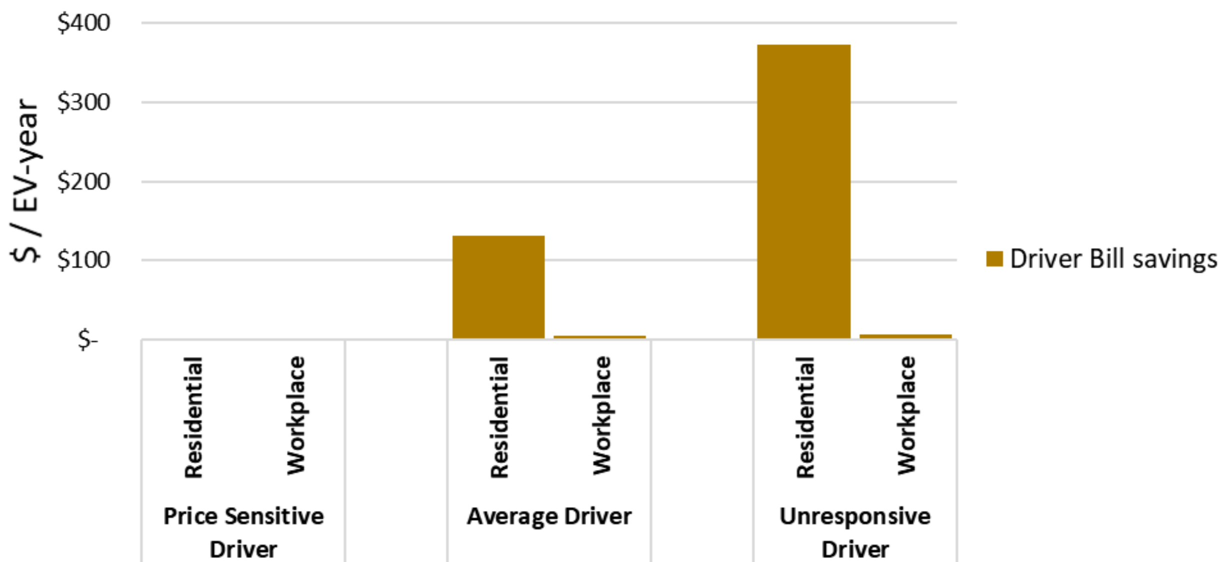
3.5.2. Shared Bill Savings

In the last section we saw that the system value created by more advanced VGI tariffs varied substantially depending on the price responsiveness of drivers used for the baseline. In this section we explore how driver bill savings varies for drivers of different price responsiveness.

For residential charging, with 100% driver participation and responsiveness the average drivers' residential charging bill under the EV-2A-TOU tariff for 2025 is $693. Since all the dynamic VGI tariffs were set to be revenue neutral the annual charging bill under each new VGI tariff is also $693. Under this construct, a potential customer who is already very price-responsive would not realize bill savings under an aggregator managed VGI rate.

However, a driver that is not at all responsive to TOU rates would pay $1,065 under the EV-2A-TOU tariff for residential charging in 2025. The aggregator can reduce this customers bill to $693 per year, a saving of $373. This creates a business opportunity for a shared bill savings approach to provide additional revenue for the aggregator. Assuming that across the population of EV drivers, only 65% of drivers are price responsive, then the average bill savings provided by the aggregator would be $130 per year, which could be shared between the driver and the aggregator (Figure 21). Signing up drivers that would otherwise be unresponsive to price signals generates substantially higher value bill savings (and system benefits) than drivers that are already price sensitive. This creates an incentive for aggregators to go after precisely those drivers that have the potential to increase system costs the most.

Figure 21 - Potential bill savings for different driver types



A recent survey of EV drivers demonstrated that incentives of $300 per year would attract at least 50% of drivers to participate in a V1G program (Shaheen, Wong, Farrar, Stocker, & Martin, 2019). For other drivers' financial incentives alone may not induce drivers to enroll. Instead, aggregators could offer other perks such as 100% renewable energy, or combine managed EV charging with other vehicle, home, or energy services. Aggregators could also offer flat rates, or fixed monthly charging subscriptions which make charging easy and convenient for drivers who may not want to think about how and when they need to charge. Consumer demand these other values should be explored through surveys and further research but could suggest drivers may even pay a premium for an aggregation service.

3.6. Summary

This section presented four advanced VGI tariffs that apply to an aggregator jointly managing charging load for a group of EVs at both residential and workplace locations. Each rate design is developed to recover the same revenue as a currently applicable TOU rate with the goal of further reducing system costs to generate further value. The goal of the analysis is not to recommend a specific rate design, but to demonstrate that advanced VGI rates can reduce system costs while fulling recovering the utility's revenue requirement.

The first VGI rate evaluated is a dynamic hourly volumetric charge based on day-ahead energy prices, with dynamic generation and distribution adders for peak load hours. This rate design successfully avoided peak charging but has highly variable secondary peaks that could impose costs on the distribution system at high penetrations of EVs. To mitigate secondary charging peaks, the next two options considered a dynamic volumetric charge with the addition of flat or TOU based non-coincident demand charges, respectively. In both cases the demand charge price signal often overpowers the dynamic energy rate leading to less flexibility, more on-peak charging and thus, higher system costs than the dynamic energy rate alone. Finally, the dynamic rate with distribution load management included a demand charge coincident with feeder load and generated greatest system cost savings compared to the TOU by avoiding on-peak charging, managing secondary distribution peaks and allowing charging at full capacity during daytime hours with excess generation.

Using 2020 CPUC Avoided Costs, we evaluate the system costs of delivered electricity for 5,000 EVs at both home and work locations in a single PG&E distribution planning area in the year 2025. We find net benefits of $41 per EV per year in moving a price-responsive TOU driver to the aggregated load management VGI. If 65% of EV drivers are enrolled in and responsive to TOU rates and 35% of EV charging is unmanaged, the average annual per EV benefits increase to $68. As compared to unmanaged charging the VGI rate reduces system costs by $133 per EV annually.

We find the system benefits of VGI are substantially higher for residential charging than for workplace charging. This is partly because more energy is generally consumed per EV at home than at work and because more EVs are likely to have access to a residential charger than workplace chargers. Furthermore, the charging capacity installed per EV at workplaces is assumed to be limited (based on NREL EVI-pro lite estimates). If workplace charging capacity is nearly fully utilized, there is limited flexibility and benefit from VGI technology. If the number of workplace chargers per EV increases (to take advantage of excess daytime solar generation for example), the benefits of VGI rates at workplaces will increase.

VGI rates can also generate large potential bill savings for drivers. The rates were designed to be revenue neutral, VGI rates do not provide bill savings for a driver that is already responding well to TOU rates. However, assuming only 65% of EV drivers are enrolled and responsive to TOU rates, VGI can provide average annual bill savings of $130 per EV. For a driver under unmanaged charging, moving to an aggregator with a VGI would provide bill savings of $373 per EV per year.

The system cost savings under VGI rates provides a basis for utilities to provide payments to an aggregator. However, the total system benefits shown in this analysis would probably not support a viable aggregator business model on their own until significant scale and cost reductions are achieved. We do believe these estimates are on the conservative side, and additional investigation could well find increased net benefits. Aggregators could also seek additional sources of revenue, for example through direct participation in CAISO markets or monetizing LCFS credits. Aggregators could also earn revenues though a shared bill savings model with the customer. Aggregators could also develop other value propositions to drivers, such as charging simplicity, 100% green charging, or other perks to make their service more appealing than charging under conventional rates. EV managed charging may also be more cost-effective when offered in combination with other driver, DER or energy management services.

4. Conclusions

Our analysis shows that VGI aggregator rates have significant potential to provide greater system benefits whilst ensuring full utility cost recovery. By billing sophisticated EV aggregators rather than residential and commercial customers, utilities can design more complex tariffs which better reflect grid costs delivering greater system benefits. Utilities can also outsource the capability to enroll drivers on dynamic rates and manage individual EV loads to EV aggregators. Finally, drivers who enroll on charging programs with the aggregator can benefit from lower EV charging costs with much greater simplicity than using charging timers and responding to TOU tariffs. Several additional insights from the modelling and analysis are also described below:

- We find NPV benefits of adopting 2.5 million EVs in PG&E’s service territory by 2030 to be $10.5 billion for drivers, $8.9 billion for ratepayers and $20 billion for the region as a whole. Net benefits per EV are $2,700 for drivers, $7,100 for ratepayers and $10,000 for the region.
- A review of the hourly charging load under the flat and TOU tariffs reveals that PG&Es on-peak TOU period aligns well with high grid costs hours resulting in large reductions in grid costs. However, since TOU tariffs apply the same price signal to all EVs to manage charging, it creates a risk of secondary peaks that could stress the distribution system. To avoid secondary peaks charging must be coordinated across the EV fleet.

- All four advanced VGI rate designs evaluated provide net system benefits compared to a baseline TOU rate and have very different impacts on EV charging load:
    - A dynamic volumetric rate avoided on-peak charging but creates potentially large secondary peaks.
    - Adding either an all-hours or TOU non-coincident demand charges flattens load but ends up shifting charging back into on-peak periods and limits flexibility to take advantage of excess renewable generation.
    - A dynamic volumetric rate with coincident demand charge for distribution load management provided the highest net system benefits (17%), avoiding on-peak charging, managing secondary distribution peaks and allowing charging at full capacity during daytime hours with excess generation.
- The best aggregator tariff generates an additional $41 per EV in grid benefits per year from switching a fully price responsive driver on a TOU rate to an advanced VGI rate. Assuming only 65% of EV drivers are responsive to TOU rates, the average annual per EV benefits increase to $68. Compared to completely unmanaged charging the VGI rate reduces system costs by $133 per EV annually.
- The best aggregator tariff generates annual bill savings of $130 per EV on average assuming a driver would otherwise respond to 65% of TOU signals. For a driver who does not manage their charging, enrolling onto the aggregation service would generate bill savings of $373 per EV per year. Aggregators could use these bill savings calculations to determine an appropriate charging rate to bill enrolled drivers to retain a share of bill savings.
- Estimates of net system benefits for these aggregation tariffs rely on the 2020 avoided costs and are therefore likely to be conservative. Further investigation could identify additional benefits such as real time energy price arbitrage, locational marginal pricing, increased utilization of excess renewable generation, and additional distribution system benefits. Other revenuew streams may also increase value for aggregators such as LCFS credits.

5. References

Advanced Energy Economy. (2018). *Rate Design for a DER Future.*

Ameren Illinois. (2020, June 19). *Power Smart Pricing FAQs*. Retrieved from https://www.powersmartpricing.org/faqs/

Ameren Illinois. (2020). *Power Smart Pricing Guide*. Retrieved from https://www.powersmartpricing.org/wp-content/uploads/2020-PSP-program-guide-ADA-Version.pdf

Avista Corporation. (2019). *Electric Vehicle Supply Equipment Pilot - Final Report.*

BMW. (2020). *BMW ChargeForward Electric Vehicle Smart Charging Program.* Retrieved from https://bmwmovement.org/wp-content/uploads/2020/07/BMW-ChargeForward-Report-R4-070620-ONLINE.pdf

Bongright, J. C. (1961). *Principles of Public Utility Rates.* Columbia University Press. Retrieved from http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf

Burger, S., Chaves-Ávila, J. P., Batlle, C., & Pérez-Arriaga, J. I. (2016). *The Value of Aggregators in Electricity Systems.* Boston: MIT Center for Energy and Environmental Policy Research.

CAISO. (2021, 2). *Participant Application Page*. Retrieved from http://www.caiso.com/participate/Pages/ApplicationAccess/Default.aspx

California Energy Commission. (2018). *Los Angeles Air Force Base Vehicle-to-Grid Demonstration.* California Energy Commission. doi:CEC-500-2018-025

California Public Utilities Commission. (2019, January 4). *Energy Division's Evaluation of Demand Response Auction Mechanism: Final Report [Public Version - Redacted]* . Retrieved from https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwiYgrqLiJ7qAhVEnp4KHUAHCEwQFjAAegQIBhAB&url=https%3A%2F%2Fwww.cpuc.ca.gov%2FWorkArea%2FDownloadAsset.aspx%3Fid%3D6442460092&usg=AOvVaw3a6jqJrbFZACmlLy1FY9po

Citizens Utility Board. (2020, February). *Charge for Less: An Analysis of Electricity Pricing for Electric Vehicles in Ameren Territory*. Retrieved from https://www.citizensutilityboard.org/wp-content/uploads/2020/02/ChargeForLess_Ameren_Final.pdf

ConEdison. (2020). *REV Demonstration Project: Smart Home Rate - 2020 Q1 Quarterly Progress Report.*

CPUC. (2015). *D. 15-07-001.* Retrieved from https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF

CPUC. (2020). *2018 SGIP Advanced Energy Storage Impact Evaluation.* San Francisco: CPUC.

De Martini, P., Brunello, T., & Howley, A. (2016). *Planning for more Distributed Energy Resources on the Grid: A Summary for Policy Makers on the Walk-Jog-Run Model.* More Than Smart. Retrieved from http://gridworks.org/wp-content/uploads/2016/09/plug-and-play-report_online_v2.pdf

E3. (2021). *Electriv Vehicle Grid Impacts Model*. Retrieved from Ethree.com: https://www.ethree.com/tools/electric-vehicle-grid-impacts-model-2/

EA Technology. (2016). *My Electric Avenue Project Close Down Report.* Retrieved from http://myelectricavenue.info/sites/default/files/documents/Close%20down%20report.pdf

ElaadNL. (2019). *Charge Management of Electric Vehicles at Home - Testing smart charging with a home energy management system.*

Energy and Environmental Economics. (2020). *2020 Avoided Cost Calculator Documentation.* Retrieved from ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2020%20ACC%20Documentation%20v1c.pdf

Engel, H., Hensley, R., Knupfer, S., & Shadev, S. (2018). *Charging Ahead: Electric Vehicle Infrastructure Demand.* McKinsey.

Faruqui, A. (2019, July 15). *Advanced Rate Design: The Eight Frequently Asked Questions*. Retrieved from https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/ards/01_brattle_ahmad_faruqui.pdf

Faruqui, A., Hledik, R., & Lam, L. (2020). *Modernizing Distribution Rate Design.* The Brattle Group.

Garnett, O., Cutter, E., & Nieto, A. (2020). *Design Principles and Options for Retail Tariffs That Support Vehicle-Grid Integration.* San Francisco: E3.

Green Mountain Power. (2019). *2018 Integrated Resource Plan - Innovative Customer Programs.*

Greentech Media. (2018, September 5). *EMotorWerks Is Using Its Network of 10,000 EV Chargers to Bid Into Wholesale Markets*. Retrieved from https://www.greentechmedia.com/articles/read/emotorwerks-wholesale-markets-ev-charger-network

Gridworks. (2020). *Final Report of The California Joint Agencies Vehicle-Grid Integration Working Group.* Retrieved from https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-6.30.20.pdf

Hildermeier, J., Kolokathis, C., Rosenow, J., Hogan, M., Wiese, C., & Jahn, A. (2019). *Start with smart: Promising practices for integrating electric vehicles into the grid.* Brussels, Belgium: Regulatory Assistance Project.

Hledik, R., Lazar, J., & Schwartz, L. (2016). *Distribution System Pricing with Distributed Energy Resources.* Lawrence Berkeley National Lab. doi:LBNL - 1005180

IRENA. (2019). *Innovation Outlook: Smart Charging for Electric Vehicles.* Abu Dhabi: International Renewable Energy Agency.

Lazar, J., Chernick, P., & Marcus, W. (2020). *Electric Cost Allocation for a New Era.* Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

Levin, R. (2018). *Basics of Rate Design as applied to Electric Vehicles.* California Public Utilities Commission. Retrieved from https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457672

New York State Energy Research and Development Authority. (2015, June). *Electricity Pricing Strategies to Reduce Impacts from Plug-In Electric Vehcile Charging in New York State*. Retrieved from https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwiK1ZTpyYzqAhVXIDQIHastDCkQFjABegQIARAB&url=https%3A%2F%2Fwww.nyserda.ny.gov%2F-%2Fmedia%2FFiles%2FPublications%2FResearch%2FTransportation%2FEV-Pricing.pdf&usg=AOvVaw3U5qmnPK7oACmKy

NREL. (2018). *New EVSE Analytical Tools/Models: Electric Vehicle Infrastructure Projection Tool (EVI-Pro)*. Retrieved from https://www.nrel.gov/docs/fy18osti/70831.pdf

Octopus Energy. (2019). *Agile Octopus: A Consumer-Led Shift to a Low Carbon Future.*

Optimise Prime. (2020). *Optimise Prime Project Progress Report.* doi:NIC Project UKPNEN03

Pacific Gas and Electric. (2020). *2021 Demand Response Auction Mechanism*. Retrieved from https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/2021-demand-response/2021-demand-response-auction-mechanism.page?WT.mc_id=Vanity_dram

Rocky Mountain Institute. (2017). *EVGO Fleet and Tariff Analysis Phase 1: California*. Retrieved from https://rmi.org/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf

San Diego Gas & Electric. (2020, June 19). *Power Your Drive*. Retrieved from https://www.sdge.com/residential/electric-vehicles/power-your-drive

San Diego Gas and Electric. (2017, January 1). *Prepared Direct Testimony of of Cynthia Fang on the Behalf of San Diego Gas and Electric, Chapter 5*. Retrieved from https://www.sdge.com/sites/default/files/Direct%2520Testimony%2520Chapter%25205%2520-%2520Rate%2520Design.pdf

San Diego Gas and Electric. (2019, May 10). Retrieved from https://www.sdge.com/sites/default/files/regulatory/March%202019%20PYD%20Report%20Final_0.pdf

Shaheen, S., Wong, S., Farrar, E., Stocker, A., & Martin, E. (2019). *Assessing Smart Charging for Electric Vehicles: Honda V1G report.* Berkeley: Berkeley Transportation Sustainability Research Center.

Smart Electric Power Alliance. (2019, May). *A Comprehensive Guide to Electric Vehicle Managed Charging*. Retrieved from https://sepapower.org/resource/a-comprehensive-guide-to-electric-vehicle-managed-charging/

Smart Electric Power Alliance. (2019). *Residential Electric Vehicle Time-Varying Rates That Work: Attributes That Increase Enrollment.* Retrieved from https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/

Synapes Energy Economics, Inc. (2020, May 4). *Best Practices for Commercial and Industrial and EV Rates*. Retrieved from https://www.nrdc.org/sites/default/files/media-uploads/best-practices-commercial-industrial-ev-rates_0.pdf

Synapse Energy Economics, Inc. (2018, June 25). *Driving Transportation Electrification Forward in New York: Considerations for Effective Transportation Electrification Rate Design (Prepared for Natural Resources Defense Council)*. Retrieved from Synapse NY EVs Report: http://www.synapse-energy.com/sites/default/files/NY-EV-Rate-%20Report-18-021.pdf

UK Power Networks. (2019). *Getting Electric Vehicles Moving.* Retrieved from https://www.ukpowernetworks.co.uk/internet/en/our-services/documents/A_guide_for_electric_fleets.pdf

Whaling, T. J., & Harty, D. R. (2019). *Workplace Charging at Honda's Torrance Campus.* Sacramento: CEC.

Wood, E. (2020). *Presentation - Electric Vehicle Infrastructure Projection Tool (EVI-Pro).* Sacramento: CEC. Retrieved from https://efiling.energy.ca.gov/getdocument.aspx?tn=234215

Xcel Energy. (2018, June 1). *Compliance filing, residential electric vehicle charging tariff, Docket No. E002/M-15-111.* Retrieved from https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={60A5CA63-0000-C11E-9F24-C36F15592A04}&documentTitle=20186-143541-01

Zinaman, O., Bowen, T., & Aznar, A. (2020). *An Overview Of Behind-The-Meter Solar-Plus-Storage Regulatory Design.* National Renewable Energy Laboratory.