Harnessing TOU Rate Complexity to Reduce Residential EV Charging Costs

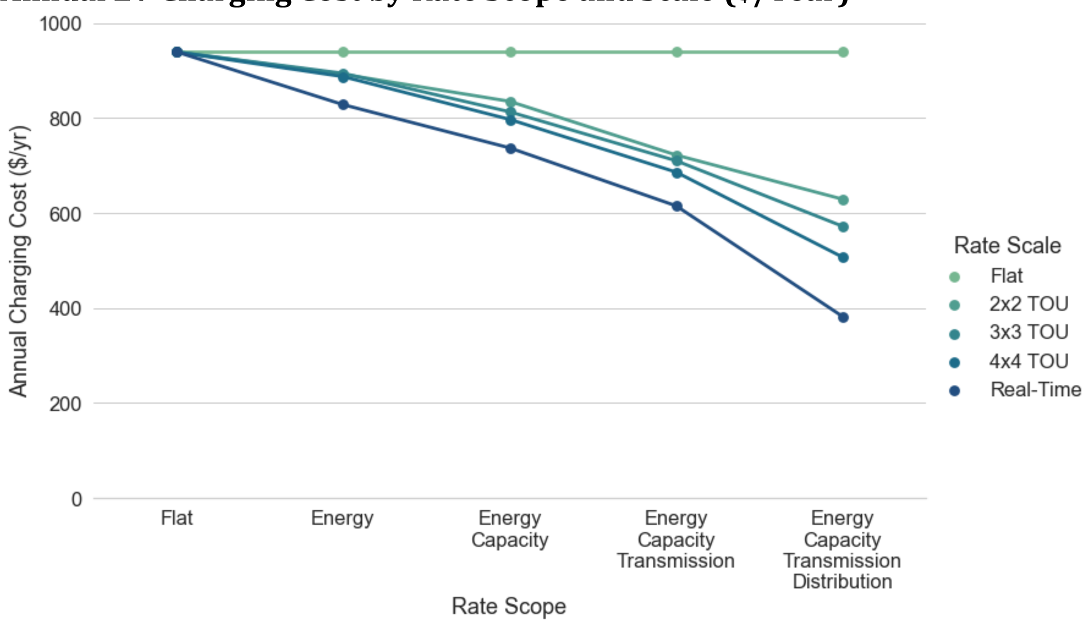
Benjamin Whitney Griffiths[1] | 2021-03-25

Abstract (182 Words)

Time-of-use (TOU) electricity rates have been proposed as a tool to reduce electric vehicle (EV) charging costs and shift consumption away from periods of system stress. TOU rates can be complicated, however, and the potential benefits of that complexity have not been comprehensively investigated. In this paper, I assess the value of two kinds of rate complexity on EV charging costs. Scope complexity relates to the number of pricing periods on the rate, while scale complexity relates to the fraction of costs given a time-varying dimension within the rate.

Looking across 17 efficient, cost-based rates, I find that adding complexity can consistently reduce EV charging costs. The most complex rates can reduce costs by half, compared to flat rates. I also find that increasing scope complexity can reduce EV charging costs more than increasing scale complexity, all else equal. A high-scope/low-scale rate triples the benefits compared to a low-scope/high-scale rate. So, instead of trying to create retail rates with many pricing periods, regulators can spur large benefits by promoting simple two-season/two-period TOU rates which span energy, capacity, transmission, and distribution cost categories.

Annual EV Charging Cost by Rate Scope and Scale ($/Year)



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1. Introduction

Electric vehicles (EVs) represent a new kind of electricity demand, one which is potentially more price-sensitive and flexible than existing household plug loads. Various payment and rate design schemes have been introduced to harness this flexibility and enable cost reductions for charging EVs. While subscription pricing[2] and managed charging[3] schemes are on the horizon, a common first step is to express the temporal variability in energy prices using time-of-use (TOU) retail electricity rates. At least 21 electric utilities have introduced some sort of EV specific TOU rate and more are actively exploring their potential.[4]

TOU rates offer a middle-ground between dynamic wholesale prices (which can vary every few minutes) and flat retail rates (which are often fixed for months on end). A customer on a TOU rate pays different amounts for electricity depending on the season (e.g., summer, winter) and time of day (e.g., off-peak, mid, on-peak periods). TOU rate schedules are known in advance, making it relatively easy to identify – and plan around – low cost periods. If EV owners charge their vehicles during off-peak periods, then they can access lower-cost electricity and, consequently, reduce their charging costs.

TOU rate development, like all ratemaking, requires tradeoffs between public acceptability, simplicity, and economic efficiency.[5] Designing an effective TOU rate can be challenging, given the range of possible considerations. Into how many seasons and periods should the year be divided? What months should be in which season, and which hours in which period? What is the ideal price differential between on-peak and off-peak periods? What cost components should be included in the time-varying rate? And so on.

Some TOU rates are relatively simple while others are quite complex, but the benefits of rate complexity have not been comprehensively investigated. To better understand how rate structure affects EV charging costs, I assess a range of hypothetical retail rates which vary in two dimensions: scope and scale. The first kind of complexity relates to the *scope* of the rate: which cost components (e.g. energy, capacity, transmission, distribution) have a time-varying dimension? The second kind of complexity relates to its *scale*: into how many costing seasons/periods does the rate bin prices?

This analysis proceeds in four steps:

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[2] *E.g.,* Austin Energy, "EV360 Plug-In Electric Vehicle Charging Subscription" plan. Available at: https://austinenergy.com/ae/green-power/plug-in-austin/home-charging/ev360.

[3] E.g., Erika Myers, "Beyond load growth: the EV managed charging opportunity fo utilities". Available at: https://sepapower.org/knowledge/beyond-load-growth-ev-managed-charging-opportunity-utilities/

[4] Ryan Hledik, John Higham and Ahmad Faruqui, 2019, "Emerging Landscape of Residential Rates for EVs", Public Utilities Fortnightly. Available at: https://www.fortnightly.com/fortnightly/2019/05/emerging-landscape-residential-rates-evs.

[5] James Bonbright. 1961. ""Principles of Public Utility Rates" Columbia University Press. Available at: http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf, at 291: "The 'practical' attributes of simplicity, understandability, public acceptability, and feasibility of application".

First, I develop a common set of real-time prices and hourly cost-allocations for five cost categories, based on ISO New England (ISO-NE) wholesale rates and Massachusetts retail billing determinants. These allocations span energy, capacity, transmission, distribution, and "other" costs.

Second, using these hourly-differentiated costs, I calculate a set of cost-based, revenue-neutral retail rates of increasing complexity of scope and scale. Each of these TOU rates is generated using an algorithmic technique which minimizes the variance between the underlying hourly energy prices and the simplified TOU rate structure. The TOU rates range from a simple uniform price in all hours to a real-time rate where energy, capacity, transmission, and distribution costs are allocated to specific hours and avoidable. In between are a variety of increasingly complicated TOU rates (with 4, 9, and 16 costing periods).

Third, I pass each of the retail rates to a simple optimization routine which identifies the least-cost charging strategy and charging cost, for a typical electric vehicle on that rate.

Fourth, I compare customer outcomes on each of the different retail rates based on two metrics: cost and efficiency.

Overall, I find that adding complexity to TOU rates can help reduce EV charging costs. Increasing scope complexity can reduce EV charging costs more than increasing scale complexity, all else equal. For example, assuming that all costs have a time-varying dimension, a simple two-season/two-period TOU rate structure with can reduce charging costs far more than a dynamic rate where only a fraction of the bill is time-varying. Instead of trying to create complicated TOU or dynamic retail rates, this result suggests that regulators may spur larger benefits simply by reexamining how capacity, transmission, and distribution costs are allocated and charged to load.

2. Methods

2a. Cost Allocation Used for Representative Rates

This analysis note breaks the retail bill into five major cost categories: energy, capacity, transmission, distribution, and "other" charges. Energy and capacity are generally considered energy supply while transmission and distribution are energy delivery. Charges that fall outside of these categories are lumped together into an "other" category.

Energy charges reflect actual consumption of electrical energy. In New England, the energy component of a retail bill is the result of energy prices set in the ISO-NE wholesale market, plus margin and various hedging arrangements by the energy supplier. Energy prices are a function of which power plant on the system is running "on the margin" at a given point in time. In peak periods, relatively expensive power plants are on the margin; in off-peak periods awash in capacity, relatively inexpensive plants serve load. Prices vary on the ISO-NE system every five minutes.

Capacity costs reflect the cost associated with ensuring the the power system will have a sufficient quantity of generators to meet the future demand for electricity. In New England, capacity is procured (and priced) through the ISO-NE Forward Capacity Market (FCM). The overall price of the FCM is set by an auction run three-years in advance and the market's cost is allocated to load based on consumption during the system's peak load hour of the year.

Charges for transmission and distribution (T&D) assets reflect previously incurred costs. A utility is allowed to collect a rate of return on existing capacity assets like poles, wires, and substations. Because these assets are fixed in the short term – the utility already paid for, and installed, this infrastructure – the rate of return on these assets is fixed. For this reason, many utilities assume that T&D costs have no temporal dimension.

While this may be narrowly true (the money has already been spent, after all), these cost categories also have a temporal dimension related to avoiding *new* infrastructure. For example, the quantity of power generation capacity or the sizing of substations are related to peak system demand. Reducing consumption in high-load periods, or adding new loads in low-load periods, reduces the need for some new infrastructure. Moreover, there is often a temporal dimension to how these costs are collected at a wholesale level. For example, transmission costs in ISO-NE are allocated to load based on consumption during the peak load hour of each month which, from the perspective of a retail customer, is equivalent to a very high marginal price in 12 hours of the year. The same general phenomenon can be extended to distribution costs. For this reason, it may be reasonable to express time-differentiation in T&D costs, even though the overall revenue requirement for those assets is fixed. (Of course, these time-varying T&D rates must be scaled to allow the utility to earn its revenue requirement.)

Finally, some bill components may not have a temporal dimension at all. These other costs might include fees for energy efficiency charges, low-income customer assistance, or renewable energy programs. For example, the value of a Renewable Energy Credit (REC), used to comply with a state Renewable Portfolio Standard, does not change based on when or where it was created: a REC minted at noon in July is just as valuable as one minted at midnight in April.

To assess the impact of different rate designs, this analysis requires a common set of hourly prices or hourly cost-allocations for each billing component. To capture heterogeneity in system conditions, this study relies on five years of historic energy data spanning 2014-2018. My specific cost allocations are as follows:

- **Energy** costs vary in each hour of the study period and are based on ISO-NE's day-ahead hourly price for the Internal Hub – the region's reference price for energy. Over the study period, the load-weighted average price of energy is $47/MWh. This is equivalent to a 4.7 ¢/kWh retail rate.[6]

[6] ISO-NE hourly pricing reports available at: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

- **Capacity** costs are allocated to the system's peak hour in line with ISO-NE's cost allocation methodology for the Forward Capacity Market and are assumed to equal approximately $90,000/MW-year.[7] This is equivalent to a 2.3 ¢/kWh retail rate.

- **Transmission** costs are allocated to the monthly system peak hour in line with ISO-NE's transmission cost allocation methodology. Transmission costs approximately $13,500/MW-month. This is equivalent to a 3.1 ¢/kWh retail rate.

- **Distribution** costs are allocated to each hour using the cost-duration curve method, developed by Lon Huber for a Liberty Utilities time-of-use pilot, and are normalized to yield a load-weighted distribution cost of 6.4 ¢/kWh retail rate.[8] This method assigns a share distribution costs to each hour of the year, by first calculating the incremental load associated with each hour on a load-duration curve, then uniformly allocating the hour's marginal load across all hours with equal or higher loads.[9] The logic of this method is that there are a small number of peak hours which spur the development of system assets covering peak demand and, on the other end, there is a minimum load level which all hours of the year exceed. In practice, this methodology assigns a significant share of distribution costs to highest load hours of the year and a smaller portion of system costs to *all* hours of the year. To increase pricing heterogeneity and reflect the fact that system peaks do not always occur in the same hours, I apply this methodology to each of the five years in the sample, individually, rather than applying it to the full 5-year dataset.[10]

- All **Other** costs are assumed fixed at $74/MWh (7.4 ¢/kWh) in all hours. The "flat" allocation of these costs reflects the fact that these other costs to not vary over time and include various programs such as RPS compliance, energy-efficiency charges, and low-income assistance.

Each of these sub-costs can be summed by hour to create an hourly *total marginal cost* (TMC) which reflects the total cost of consumption in each hour of the year.

Hour costs for each sub-component, and for the TMC are presented in Figure 1. This figure shows that energy prices vary at a high frequency and that in some winter periods prices

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[7] This is approximately equal to the 5-year average FCM clearing price, as allocated to load. See. ISO-NE "Results of the Annual Forward Capacity auctions", available at: https://www.iso-ne.com/about/key-stats/markets#fcaresults.

[8] Heather Tebbetts, Lon Huber, and Clifton Below, 2018, "Technical Statement Regarding Time-of-Use (TOU) Model", NHPUC Docket No. DE 17-189. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_ENGI_TECH_STATEMENT_TOU.PDF

[9] Numerically, $Weight_h = \sum_h^H \Delta Q_h + \frac{1}{2}\Delta Q_{h+1} + \frac{1}{3}\Delta Q_{h+1} + \cdots + \frac{1}{n}\Delta Q_{h+n} \quad \forall h \in Hours$

$Where, \Delta Q_h = Q_h - Q_{h+1}$

[10] This allocation methodology was selected out of expedience because it does not require engineering studies to assess the temporal variability of individual system components. Other cost allocations may, of course, affect results.

are at elevated levels for days or weeks. Capacity and transmission costs are assigned to a relatively small number of hours over the five-year study period (5 and 60, respectively). Distribution costs are largely allocated to summer peak periods, when load levels are at their highest, and quite low otherwise. Table 1 provides descriptive statistics for each cost component.

Figure 1: Hourly Costs by Cost Component, 2014-2018 ($/MWh)

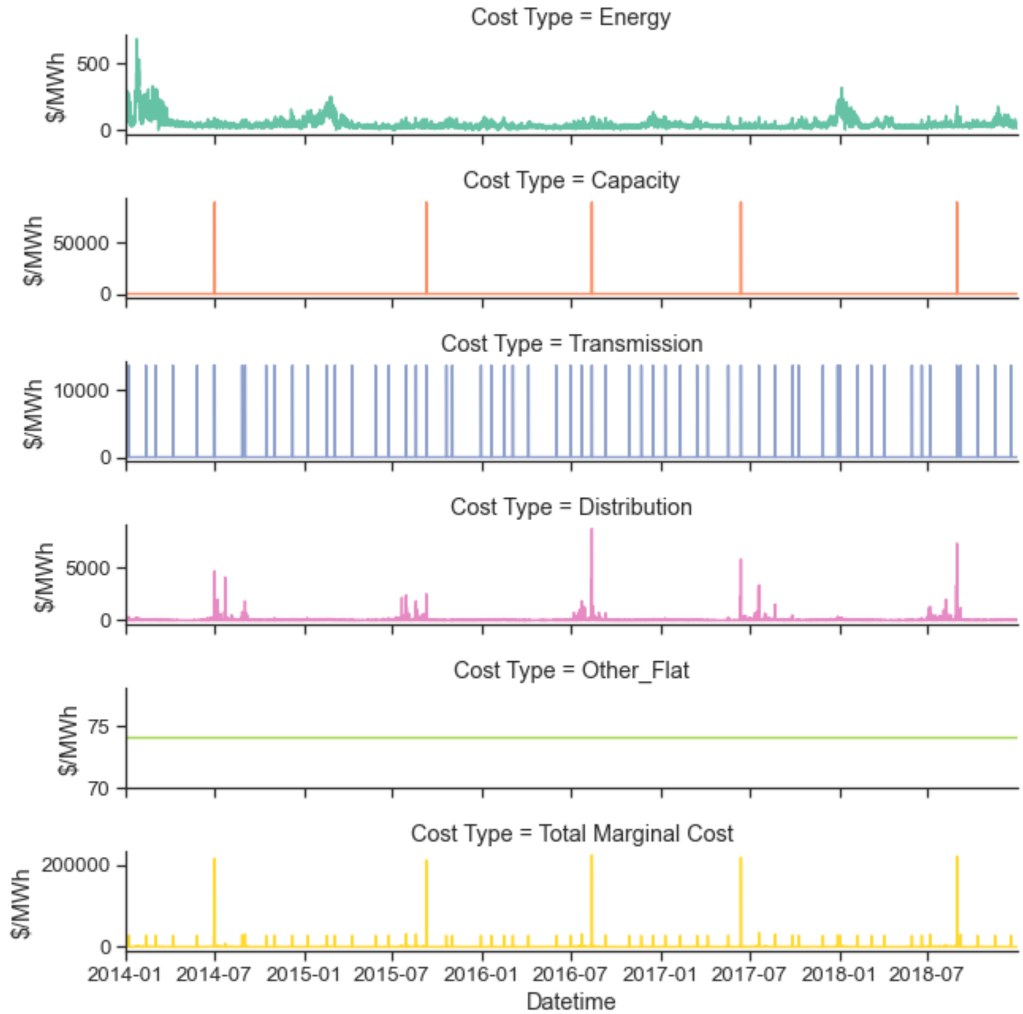

Table 1: Descriptive Statistics by Cost Category ($/MWh)

	Energy	Capacity	Transmission	Distribution	TMC
mean	42.74	10.19	18.51	41.56	186.99
std	39.33	953.83	499.84	153.28	1,269.07
min	-5.00	0.00	0.00	0.00	71.27
25%	22.83	0.00	0.00	10.16	109.26
50%	31.16	0.00	0.00	18.02	125.88
75%	45.70	0.00	0.00	31.15	155.41
max	688.16	89,302.07	13,517.74	8,588.59	111,576.67

***Note**: the mean in first row is the simple average value across the full dataset, not the load-weighed value.*

It is possible to create rates of varying scopes by holding some costs constant across all hours of the year, while letter others vary. The five sets of prices used for this analysis are as follows:

- **Price 1 (Flat):** All costs held constant;
- **Price 2 (E):** Energy costs time-varying, other costs held constant;
- **Price 3 (EC":** Energy and capacity costs time-varying, other costs held constant;
- **Price 4 (ECT):** Energy, capacity, and transmission costs time-varying, other costs held constant;
- **Price 5 (ECTD):** Energy, capacity, transmission, and distribution costs time-varying, other costs held constant.

Critically, each of these sets of prices have the same load-weighted *average* price, 23.9 ¢/kWh, but different price distributions and different levels of price volatility. The hourly prices with more time-varying cost components are more variable than the hourly prices where some/all cost components are held fixed.

2b. Development of Efficient, Cost-Based, Revenue-Neutral Retail Rates

For this analysis I develop five different tariff structures of increasing temporal scale.

Structure A: Simple uniform price tariff for all hours of the year;
Structure B: Two-season/two-period (2x2) TOU tariff;
Structure C: Three-season/three-period (3x3) TOU tariff;
Structure D: Four-season/four-period (4x4) TOU tariff;
Structure E: Real-time pass-through rate where prices vary in every hour.

The rate structures are independent of the prices discussed above and each set of prices can be combined with each tariff structure. Combining the prices with the structures yields 25 discrete Price/Structure pairs, reflecting various levels of TOU scope and TOU scale. Of these, there are 17 unique options, because rates with flat prices or a single period resolve to the same outcome.

With hypothetic tariff structures and underlying cost data established, specific rate schedules can be developed. These rate schedules define which months are in each season, which hours are in each period, and the price of energy in each season/period combination. The prices/periods for tariff were developed using the methodology outlined in the whitepaper *Algorithmically developing efficient time-of-use electricity rates*.[11] This paper offers an objective method for developing multi-season, multi-period TOU rates by identifying the TOU periods/seasons/prices which minimize the hourly variance between the underlying hourly cost allocations and the retail rates, for a given customer class.[12]

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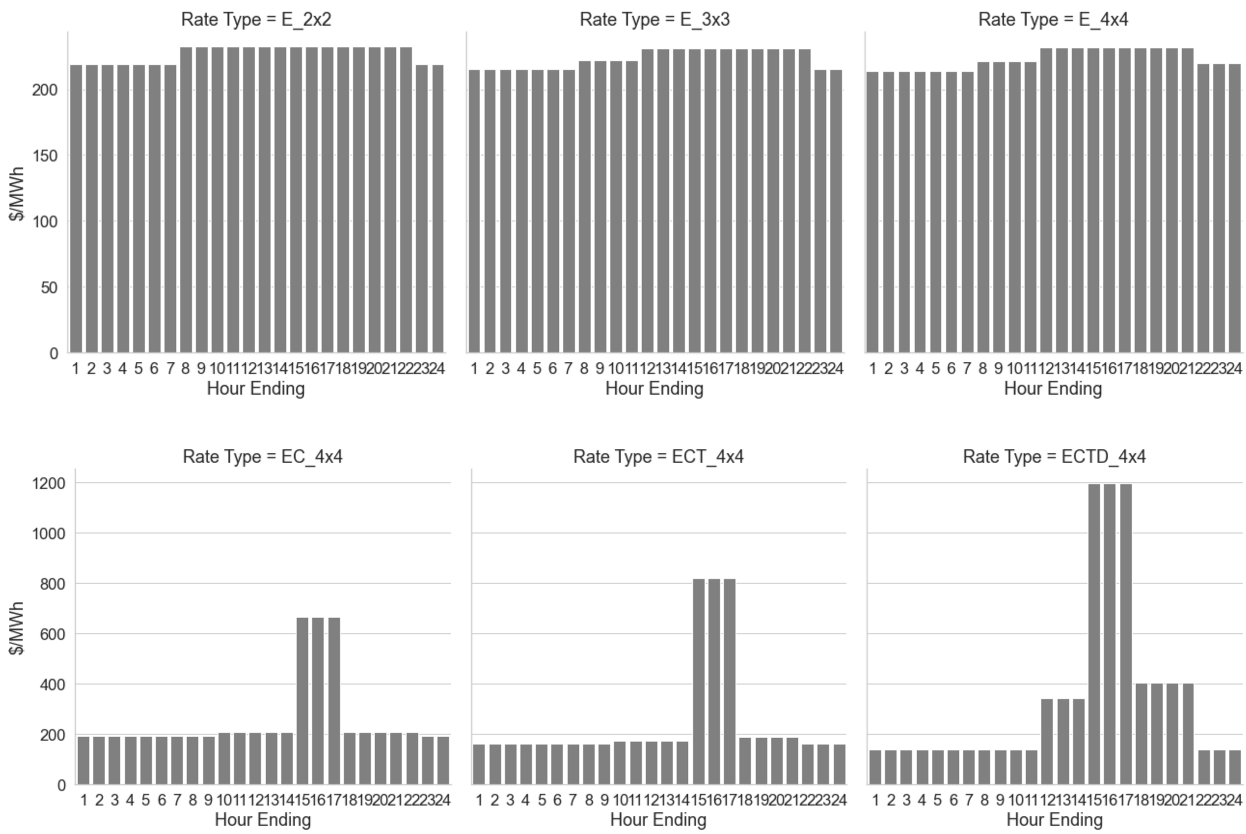
[11] Ben Griffiths, 2020, "Algorithmically developing efficient time-of-use electricity rates" Available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3732850.

[12] Residential load profiles are sourced from the from the National Grid (Massachusetts Electric Co.) default service RFPs. More specifically, a composite hourly residential load profile is generated for the full study

The resulting rate schedules are provided in Appendix A. The simple flat rate has a constant price of 23.9 ¢/kWh across the whole study period, while the 4x4 TOU based has 16 pricing periods with rates ranging from 11.5¢/kWh to 119.7 ¢/kWh. Figure 2 depicts hourly prices for six select rate designs on July 1. The upper row shows how rates evolve with increasing scale complexity, holding scope constant with a time-varying energy TOU rate. The lower row depicts how rates evolve as scope increases, holding scale constant.

Figure 2: Select TOU Rates for July 1 ($/MWh)



Even though the retail rates have different price distributions, the total cost of serving baseline household load (excluding EV charging) is equal across each of the 17 unique rates.[13] This is by design. This means that a normal household which is not price-responsive, will pay exactly the same amount of each cost category on the flat, TOU, or real-time rates: $1,891/year. And, because the household costs are assumed invariant across the different rate designs, cost recovery on fixed assets is ensured. This means that the utility meets its revenue requirement for transmission and distribution costs.

period, by dividing hourly residential default service load by daily residential load tags (annual capacity contribution). *See* https://www9.nationalgridus.com/energysupply/current_procurement.asp.

[13] Assuming baseline consumption of 650 kWh per month and no change in consumption.

2c. EV Charging Strategy

I assume that residential EV customers can and will respond to TOU rates by charging their cars in low cost periods, to the extent that they are able. To understand how EVs would respond to these competing tariffs, I develop a simple optimization routine which minimizes the cost of charging an EV over a five-year period, based on an exogenous rate schedule. (A full description of the linear program is provided in Appendix B). The model assumes that each EV:

- Has a 75 kWh battery and consumes 0.24 kWh per mile driven (in line with a Tesla Model 3)[14];
- Drives 41 miles each day (15,000 miles per year, evenly distributed);
- Charges entirely at home[15];
- Is plugged in each day between 6PM and 8AM;
- Can draw charge at a maximum rate of 11.5 kW/h (in line with an Enel X JuiceBox 48)[16];
- Has perfect foresight of energy prices and can optimally/instantaneously respond.

By default, an EV will trickle charge during the lowest price periods each night (when it is plugged in at home), but it can also optimize charging patterns over days/weeks if exposed to real-time prices. Perfect foresight can certainly be achieved for TOU rates, as the prices are known in advance, but is unlikely to be realized in practice for EVs on real-time rates. To that end, this assumption provides a "best-case" lower bound for EV charging costs.

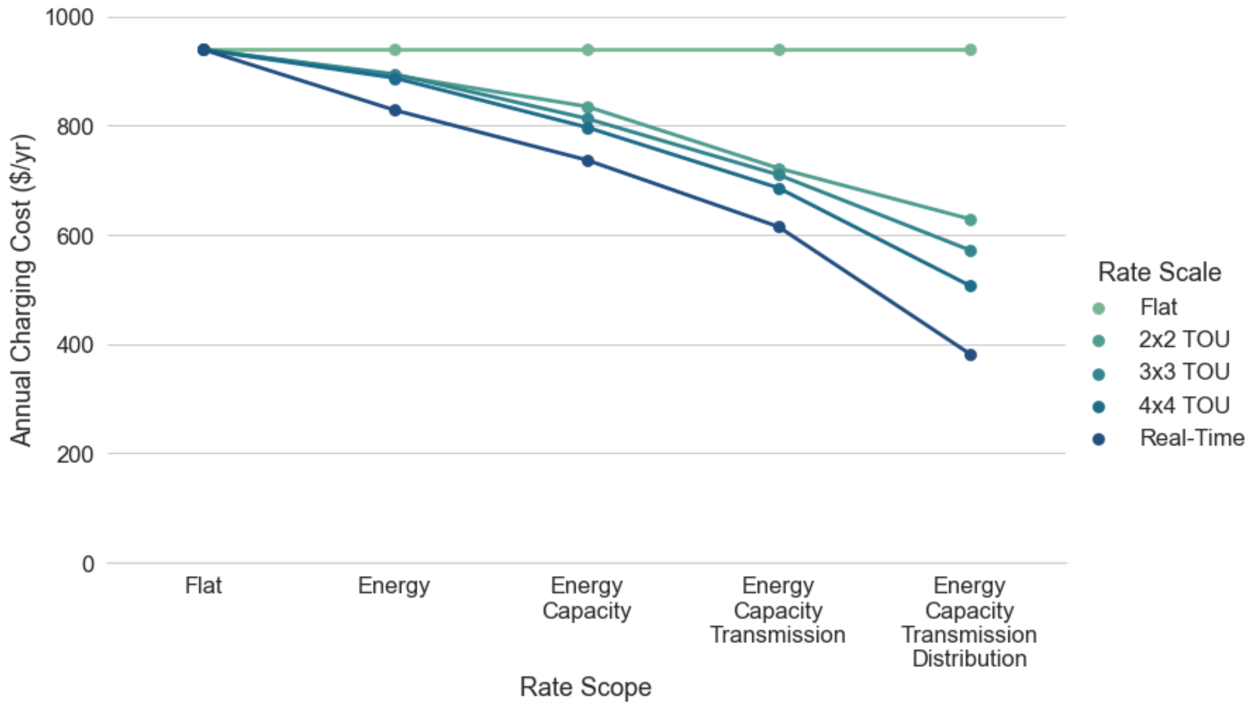
3. Results

3a. TOU Rates Can Reduce EV Charging Costs by Half

Increasing rate complexity decreases EV charging costs. This holds for increasing both the complexity of scope and the complexity of scale. Figure 3 depicts the annual average cost to charge an EV, by tariff structure. Each *point* on the figure reflects the cost of one tariff, given its scope and scale. Scope complexity increases from left to right with a no time-varying costs on one end, and all costs time-varying on the other. Each *line* connects rates of a given scale (i.e., a flat rate, a 2x2 TOU, a 3x3 TOU, a 4x4 TOU, and real-time pricing).

[14] https://www.fueleconomy.gov/feg/Find.do?action=sbs&id=42278
[15] Consumer EVs are charged almost entirely at home. E.g., https://www.energy.gov/eere/electricvehicles/charging-home.
[16] https://evcharging.enelx.com/store/residential/juicebox-48

Figure 3: Customer Payment for EV Charging by Rate Scope and Scale ($/Year)



Increasing scope complexity decreases EV charging costs across the board. It costs $939/year to charge an EV on the flat rate. Moving to an energy-only 2x2 TOU rate reduces costs to $892/year (-$47; -5%) over a flat rate. At the other extreme, it costs $722/year to charge an EV on a 2x2 TOU where energy, capacity, transmission, and distribution costs are all time-varying. This amounts to a 23% (-$217) reduction in EV charging costs. The cost reductions associated with scope increases hold true for all of the time-varying retail rates.

Turning to scale complexity, increasing the number of pricing periods also reduces EV charging costs. At one extreme, EV charging costs are at their highest when on a flat rate; at the other extreme, EV charging costs are lowest if one a real-time rate. The three TOU rates sit in between: for a given scope they offer lower charging costs than the flat rate but higher charging costs than the real-time rates.

The tight clustering of the three TOU rate structures indicates that is relatively little value to increasing the scale complexity of a TOU rate. In most cases, a 2x2 TOU does nearly as well as the 3x3 or 4x4 in terms of charging costs. For example, the three TOU rates with time-varying energy costs range from $887/year to $894/year (a $7/year range). The benefit of increasing scale complexity from a 2x2 to a 4x4 TOU on higher scope rates is also modest. For example, the 4x4 EC and ECT rates yield incremental savings of less than $40/year compared to the simpler 2x2 alternative.
By contrast, shifting from a 4x4 TOU rate to a real-time rate provides more meaningful incremental savings: $59 to 125/year. The persistent benefit of real-time pricing, compared to any TOU rate, relates to the fact that an EV on a real-time rate can selectively charge during the lowest of low-priced overnight hours, rather than be reliant on any sort of price aggregation. (All TOU rates reflect for the fact that some hours in a given TOU

period have prices higher than the TOU rate and hours have prices which are lower than the TOU rate.)

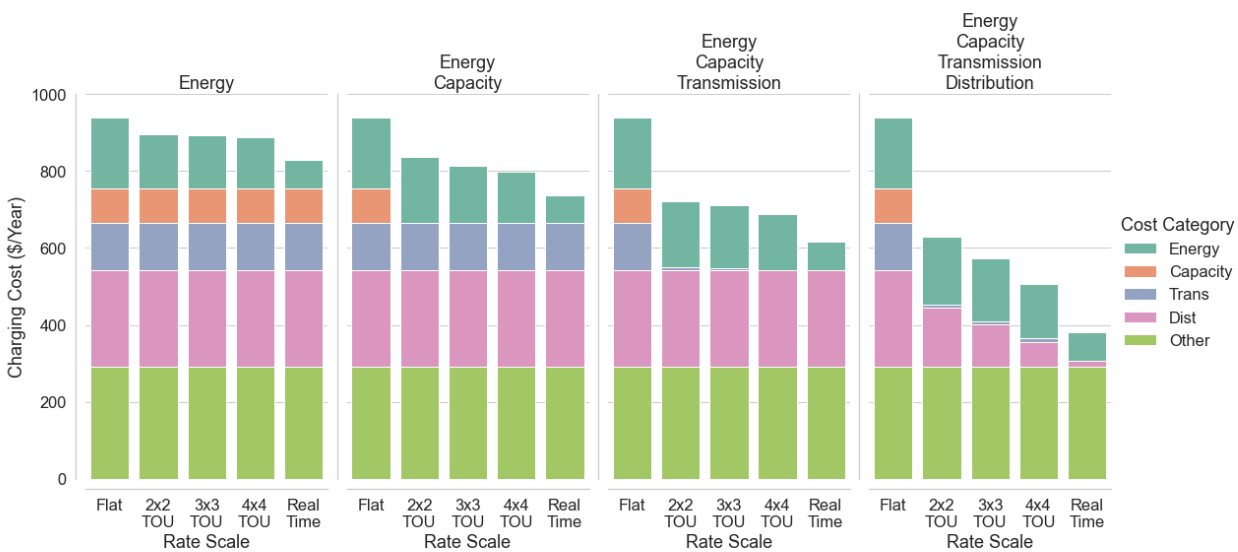
All else equal, increasing scope complexity yields larger benefits than increasing scale complexity. For example, the 2x2 ECTD TOU rate ($629/year) is lower than all of the examined TOU rates based on lower scopes. The ECTD 2x2 TOU also yields lower or equivalent annual charging costs than real-time rates with E, EC, or ECT cost allocations. Rates with high scope complexity and low scale complexity result in significantly lower changing costs than the opposite.

<u>3b. Cost Savings Associated with TOU Rates Largely Result from Avoiding Incremental Capacity, Transmission, and Distribution Costs</u>

What drives these cost reductions the more complicated rate structures? In large part, the answer is the avoided capacity, transmission, and distribution costs. The cost savings associated with increased scope are relatively consistent by scale because any rate that includes a time-varying capacity or transmission charge will allocate most, or all, of those charges to peak periods (which consequently reduces the off-peak rate). That yields lower off-peak rates and lower EV charging costs.

This phenomenon can be observed in Figure 4, which decomposes a customer's overall EV charging bill into component. In Figure 4, rates of a given scope are clustered into groups of bars, and each bar within a given group reflects a different scale.

Figure 4: Customer Payment for EV Charging, by TOU Rate and Bill Subcomponent ($/Year)



If energy costs are the only category which varies by time, then overall rate reductions are limited because capacity, transmission, distribution, and other costs are constant. For the energy *subcomponent,* however, costs can be reduced by about one-third by moving to a TOU rate and by about two-thirds by moving to a real-time rate. On a flat rate, energy costs are about $180/year while energy costs on TOU rates fall to about $140/year, and real-time rates enable energy costs of $75/year. The difference in energy charging cost *between* the TOU rates (e.g. a 2x2 vs. a 4x4) is generally only a few dollars per month (the middle three columns on the left-most subplot).

Considering the middle two subplots, if capacity or transmission costs are within the scope of the TOU, then EVs charging in nighttime hours avoid approximately 100% of these costs. This is because transmission and capacity costs are allocated to system's peak load hours so an EV charging in the middle of the night will not induce new capacity or transmission costs nor be charged for these costs. The step-change in EV charging costs when moving between rates of different scopes, observed in Figure 3, is the result of these rates recovering little-to-no capacity and transmission cost in the off-peak periods.

Distribution costs are reduced for the same reason, albeit to a lesser degree. Unlike energy costs where adding more TOU periods does not materially reduce costs, increasing the number of TOU periods provides incremental reductions in distribution costs. In the far right subplot, shifting from a flat rate to a 2x2 TOU reduces charging costs by $100/year while shifting from a 2x2 to a 3x3 or from a 3x3 to a 4x4 reduces costs by around $50/year

Finally, because I assume that "other" costs have no temporal dimension, these costs remain constant at $290/year. This is an irreducible cost from a *rate* perspective (e.g. fixed $/MWh), but "other" costs are reduced if less energy is consumed. This irreducible quantity also accounts for a significant fraction of the overall EV charging cost on more complex rates. While the other costs account for about 30% of the flat rate, they account for 45% to 76% of charging costs on the ECTD time-varying rates (far right on Figure 4). This suggests that there are limits to how low EV charging costs can reduced.

<u>3c. TOU Rates Can Align Customer Bills and Utility Costs</u>

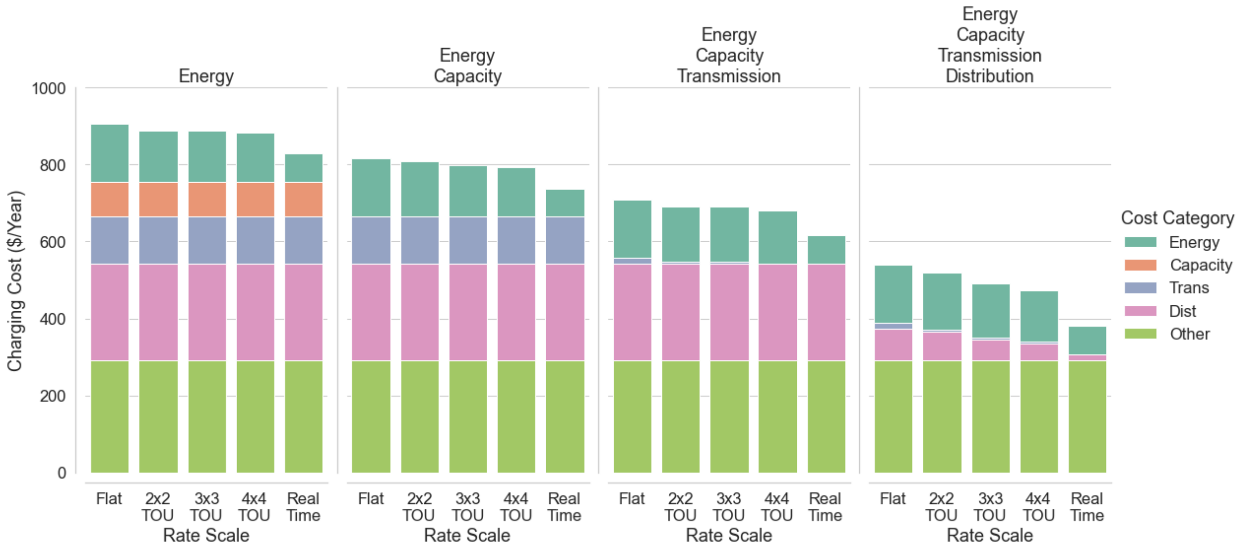
Given the dramatic reduction in payment for some cost categories observed in Figure 4, it is worth confirming whether EV customers are paying their share of system costs if they pay a lower rate for charging during off-peak periods as part of a TOU rate.

I assess the relative economic efficiency of the various retail rates assessed by comparing category level revenue recovery under the TOU rate, compared to underlying hourly costs required to provide the service, based on the assumed cost allocations. Economic efficiency is important because it provides insight into whether customers are paying their "fair share" of inter- and intra-class costs.

(While not the focus of this analysis, recall that the rates developed in this analysis ensure that the revenue requirement for capacity, transmission, and distribution costs are always collected from electricity consumers. For these cost categories, these rates are revenue neutral for the load serving entity, once household energy costs are factored in.)

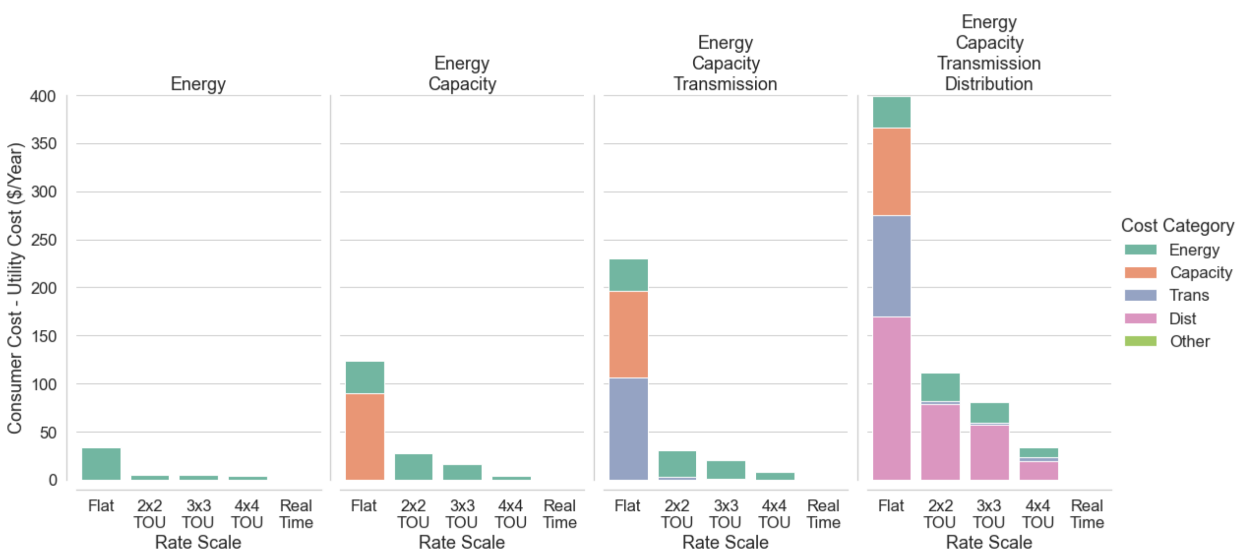
Figure 5 depicts what it cost the utility to provide the EV with service, based on the hourly total marginal cost described in Section 2a. At a glance, Figure 5 and Figure 4 look very similar, with the exception of the flat rates which are much lower. The similarity between what EVs pay for service and what it costs the utility to provide that service suggests that the TOU rates closely track the underlying real-time costs associated with EV charging.

Figure 5: Utility Cost of Serving EV Charging Load, by Bill Subcomponent ($/Year)



The total charging bill paid by an EV owner on a TOU rate is generally within a few percent of the real-time cost of providing that service. In fact, real-time cost to provide the service is always *lower* than the EV payment. For the most part the difference is modest, generally less than $10/year. Overall, the deviation between costs paid and costs incurred accounts for only a few percent of annual costs. This can be observed more closely in Figure 6, which depicts the difference between what a customer pays for EV charging (Figure 4) and the cost to serve that load (Figure 5).

Figure 6: Difference Between Customer Payment for, and Cost of Serving, EV Charging Load ($/Year)



***Note**: Positive values indicate that customer costs exceed utility costs.*

Turning to specific sub-costs, I find that EV owners are paying a few percent more for energy than what it costs to provide the service, reflecting the fact that the hours when EV charge are, on average, even cheaper than the average off-peak TOU rate. On a TOU rate, the price paid for capacity and transmission services closely match the cost of providing those services (hence the bars for these cost categories are all but invisible on Figure 6).

The difference between the cost and charge of providing distribution service can be much larger, depending on assumed cost allocation. For example, an EV on the 2x2 rate with time-varying distribution costs pays $79/year more in distribution costs than it than it incurs on the system. This suggests that hourly distribution costs may not cleanly align with the TOU periods.

While TOU rates appear to broadly match customer and utility costs, Figure 6 offers a finding that is more obvious still: flat rates designed around household load do not appear to accurately represent EV charging costs. For example, on a flat rate an EV is paying about $90/year for capacity costs and $106 in transmission costs even though that EV charges entirely off-peak. Based on the cost allocations assumed, this means that EV owners are paying nearly $200/year in capacity and transmission costs that they did not cause. In the most extreme case, flat rates charge EV customers nearly $400/year more than the cost to serve their EV load, or in slightly different terms, EV customers on a flat rate would pay nearly 75% more than their cost of service.

4. Discussion

This analysis indicates that retail tariffs for electricity can be developed which materially reduce the cost of EV charging. Consumer cost reductions can be achieved by increasing both the scale of a time-varying tariff (adding more time periods) and its scope (adding more time-varying cost categories). Rates with high scope complexity and low scale complexity result in significantly lower changing costs than the opposite. While creating rates with many pricing periods provides some benefit, far more is attained by extending time-varying treatment to capacity, transmission, and distribution costs. From a cost allocation and rate design standpoint these results yield four key insights.

First: EV TOU rates can reduce charging costs by up to half, compared to a flat rate.

Second, temporal allocation of transmission and distribution costs requires careful consideration going forward, as these cost categories have the potential to reduce EV charging costs most significantly.

Third, time-varying rate designs with a relatively small number of seasons/periods can unlock much of the theoretical value associated with more complex rate structures.

Fourth, the identified customer bill reductions on EV TOU rates are not subsidies; rather, they better reflect the actual cost of charging EVs in certain low-cost periods.

4a. EV TOU rates can reduce charging costs my more than half.

Sections 3a demonstrates that TOU rates can provide price signals that effectively identify when system costs are typically high and when they are low. EVs, which can selectively charge during low cost periods (and avoid high cost periods), can improve their economics by doing so. Reducing charging costs can put more money in a consumer's pocket, increase EV cost-effectiveness compared to conventional automobiles, and help states achieve their climate targets. Given the enormity of the electrification challenge ahead of us, TOU rates look like they will be a critical tool to convince people to move to EVs and reduce the financial burden of so doing.

Figure 3 indicates that a majority of the time-varying rates investigated can reduce charging costs by hundreds of dollars per year. The most complex TOU rates can cut charging costs in half. TOU rates with less scope or scale complexity can still reduce customer charging costs by a quarter or a third.

Shifting from a TOU rate (with fixed pricing by season/period) to a real-time rate with prices which vary hourly facilitates even lower charging costs. The difference between the charging costs on the best TOU rate and the real-time rate suggests that there is an opportunity for managed charging technologies and providers to more efficiently control when and how EVs are charged. The incremental benefit of real-time rates exists at all examined scopes suggesting that there is some level of cost reduction which even a very complicated TOU rate cannot unlock, due to heterogeneity of prices within a costing period.

4b. Cost allocation of transmission and distribution matters

Simple, low-scope TOU rates can provide some bill savings and familiarize customers and policymakers with the concept of time-varying rates. An energy-only TOU can reduce a customer's all-in bill by $47/year, while a TOU alternative to for basic service – which includes energy and capacity – increases the cost savings to $104-$142/year. (These relatively simple TOU rates may also offer other benefits not assessed in this analysis, such as the societal benefit of avoiding new transmission and distribution infrastructure.) Given generally low uptake of voluntary TOU rates observed nationwide, it seems possible that this level of savings may be insufficient to overcome a customer's "activation energy" required to switch rates.[17]

Higher scope TOU rates that factor in transmission and distribution costs, however, can double or triple customer savings. A 2x2 TOU rate which spans all cost categories can save customers approximately $310/year (compared with $104 if the TOU only extends to energy and capacity). Incorporating time-varying T&D costs into a TOU rate triples the benefits over a TOU rate that only includes energy and capacity costs. While counter-intuitive, these results imply that a regulator could actually generate stronger incentives to encourage EV charging in specific time-periods by developing T&D TOU and leaving energy and capacity charges flat – rather than the opposite.

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[17] *See* Hledik, Faruqui, and Warner, 2017, 2-5. http://files.brattle.com/files/12658_the_national_landscape_of_residential_tou_rates_a_preliminary_summary.pdf

Even in markets with retail choice, regulators can still play a critical role in creating societally beneficial rates for EVs by including T&D TOU rates, because delivery charges generally fall outside of the domain of competitive offerings. If competitive suppliers can only create alternative rates structures for supply costs, then they are fundamentally unable to unlock the lion's share of potential TOU value. This fact implies that regulators are uniquely situated to enhance the cost-effectiveness of EVs by considering T&D or all-in TOU rates.

4c. TOU rates with a limited number of periods can unlock a large share of value

Shifting from a flat rate to *any* time-varying rate enables some cost savings. Figure 3 indicates, however, that scope complexity can reduce EV charging costs far more than increasing scale complexity. A simple two-season/two-period TOU rate where all costs are time-varying outcompetes a dynamic rate where only a fraction of the bill is time-varying.

The benefit of low-scale TOU rates can be easily observed in Figure 3. The 2x2 TOU accounts for 42% to 67% of the theoretical cost savings associated with a given scope.[18] In large part, this is because higher-scope rates can easily allocate most capacity, transmission, and distribution costs to peak-periods and allow the off-peak rate to reflect only marginal generating costs plus costs which are not time-varying. That phenomenon is observed in the bill compositions in Figure 4 and Figure 5, but can also be observed in the large wedge of benefits between the flat rate and 2x2 TOU on Figure 3.

Under most conditions, folding an additional cost category into the time-varying rate provides a larger incremental benefit than increasing the number of periods (holding scope constant). The sequence of rate modifications that would facilitate the largest incremental reduction in EV charging costs would be to increase scope until all costs are time-varying, then increase scale by adding additional periods to the time-varying rate. Adding an additional cost category into a 2x2 TOU rate reduces charging costs by $47/year to $113/year. By contrast, shifting from a 2x2 to a 3x3 TOU rate structure reduces costs at half the pace. Skipping over increasing complex TOU rates and going straight from a simple 2x2 TOU to full real-time pricing enables customer savings worth an additional $100/year. (This additional $100/year assumes perfect foresight of energy prices and an optimal managed charging strategy, conditions that are unlikely to manifest themselves in practice.)

One additional consideration: rate complexity affects different parties differently. A TOU rate with a limited number of seasons/periods but a single price in each period make it easy for customers to effectively respond. A 2x2 rate with one cost categorizing time-varying is just as easy to accommodate as a 2x2 rate where all costs are time-varying. Assuming, as I do, that the TOU periods are consistent across cost categories, there should be no confusion about when it is best to charge an EV. By contrast, increasing scope complexity is largely a burden for regulators: they need to decide how to equitably allocate transmission and distribution costs. While this may require economic or engineering

[18] Share of Benefits = (Flat – 2x2 TOU) / (Flat – RT)

studies, this effort fits squarely within conventional cost-allocation and rate-design proceedings, and is all-but-invisible to actual electricity consumers. Given concerns about the understandability and acceptability of TOU rates with many seasons/periods, this suggests that regulators generate high quality rates by increasing complexity only along the scope axis.

4d. Identified customer bill reductions on EV TOU rates reflect the actual cost of charging EVs in certain low-cost periods.

The identified EV customer savings associated with complex TOU rates are neither a subsidy nor a shift in costs to other classes. The observed bill savings are possible because the EV provides a new source of load which can increase a customer's load-factor[19] but need not increase that customer's peak demand. If EV charging does not increase the system's peak demand, then the marginal cost of that incremental consumption should be lower than the average cost of consumption. Or, put in slightly clearer terms, the cost of serving some new load in the middle of the night should be a lot cheaper than serving that same new load were it to occur during the summer or winter peak.

The TOU rates which efficiently assign most capacity, transmission, and distribution rates to peak periods unlock this value. In this way, an EV owner on the TOU rates with low T&D costs in off-peak periods is paying almost exactly the same share of system costs that they did without the EV (see Figure 5). As customer costs on a TOU closely align with utility costs, this is the *right* amount of T&D cost, assuming that the residential EV charging does not spur new common T&D plant costs. When an EV charges during peak hours, however, it will also pay for incurred incremental T&D costs embedded in the on-peak rates. (Of course, if EV adoption necessitates T&D system upgrades it is also likely that the underlying cost allocations – and the TOU rates themselves – will need to be revised.)

5. Conclusions & Policy Implications

Regulators and policymakers should consider ways to change retail rates to support the electrification of the transportation sector. Developing cost-based, time-varying retail rates is an obvious strategy to reduce EV charging costs. Current flat rate structures may slow the growth of EV adoption, because they do not allow EVs to access low-priced off-peak power prices. Rate structures that do not contemplate the time-varying dimension of transmission, distribution or capacity costs may also spur higher-than-necessary EV charging costs.

Given that complexity can help control charging costs but complexity can also create regulatory burden (rate cases) and customer confusion, it is also important to identify paths that offer the largest rewards. Rates with high scope complexity and low scale complexity result in lower changing costs than the opposite. Instead of trying to create complicated TOU or dynamic retail rates, this result suggests that regulators may spur larger benefits simply by reexamining how capacity, transmission, and distribution costs are allocated and charged to load.

[19] The ratio of annual average energy consumption to peak instantaneous demand.

This analysis offers clear policy guidance: even the most sophisticated retail rate will not unlock deep charging benefits, if it does not account for the temporal nature of many energy supply and energy delivery costs. Critically, even a robust competitive market offering sophisticated TOU alternatives to basic service cannot unlock a significant share of benefits of time-varying prices, because T&D costs fall outside the scope of these competitive offerings. As majority of the possible charging benefit is tied up in the treatment of T&D costs, regulators are uniquely situated to enhance the cost-effectiveness of EVs by considering T&D or all-in TOU rate structures.

Appendix A: Tariff Sheets

Tariffs were developed using the methodology outlined in the whitepaper *Algorithmically developing efficient time-of-use electricity rates.* This paper identifies the periods/seasons and TOU prices which minimize the hourly variance between the wholesale and retail prices, for a given customer class. Months boundaries for each season are inclusive; period hours are inclusive and flagged based on the Hour Ending convention (e.g. 12AM-1AM is HE1; 11PM-12PM is HE24).

Flat Rate

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
All	**All**	23.90	4.70	2.30	3.10	6.40	7.40

2x2 TOU with Time-Varying Energy (E_2x2)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
January-March	**7-22**	27.50	8.30	2.30	3.10	6.40	7.40
	23-6	25.46	6.26	2.30	3.10	6.40	7.40
April-December	**8-22**	23.24	4.04	2.30	3.10	6.40	7.40
	23-7	21.90	2.70	2.30	3.10	6.40	7.40

2x2 TOU with Time-Varying Energy & Capacity (EC_2x2)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
September-May	**16-21**	25.11	6.08	2.13	3.10	6.40	7.40
	22-15	21.78	4.88	0.00	3.10	6.40	7.40
June-August	**15-18**	52.50	4.59	31.01	3.10	6.40	7.40
	19-14	19.92	3.02	0.00	3.10	6.40	7.40

2x2 TOU with Time-Varying Energy, Capacity, & Transmission (ECT_2x2)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
September-May	**16-21**	31.07	6.08	2.13	9.06	6.40	7.40
	22-15	18.97	4.88	0.00	0.30	6.40	7.40
June-August	**15-18**	65.56	4.59	31.01	16.16	6.40	7.40
	19-14	16.82	3.02	0.00	0.00	6.40	7.40

2x2 TOU with Time-Varying Energy, Capacity, Transmission, & Distrib. (ECTD_2x2)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
October-June	**17-20**	34.37	6.31	2.62	12.96	5.08	7.40
	21-16	14.86	4.90	0.00	0.26	2.30	7.40
July-September	**15-18**	97.53	4.78	32.11	16.83	36.42	7.40
	19-14	19.90	3.15	0.00	0.00	9.35	7.40

3x3 TOU with Time-Varying Energy (E_3x3)

TOU		Prices (Cents/kWh)					
Season Months	Period Hours	Total	Energy	Capacity	Trans	Dist	Other
January – March	18-21	28.57	9.37	2.30	3.10	6.40	7.40
	7-17	27.08	7.88	2.30	3.10	6.40	7.40
	22-6	25.64	6.44	2.30	3.10	6.40	7.40
October – December	17-21	24.54	5.34	2.30	3.10	6.40	7.40
	7-16	23.44	4.24	2.30	3.10	6.40	7.40
	22-6	22.63	3.43	2.30	3.10	6.40	7.40
April – September	12-22	23.14	3.94	2.30	3.10	6.40	7.40
	8-11	22.24	3.04	2.30	3.10	6.40	7.40
	23-7	21.55	2.35	2.30	3.10	6.40	7.40

3x3 TOU with Time-Varying Energy & Capacity (EC_3x3)

TOU		Prices (Cents/kWh)					
Season Months	Period Hours	Total	Energy	Capacity	Trans	Dist	Other
September – February	16-21	26.59	6.68	3.00	3.10	6.40	7.40
	7-15	22.71	5.81	0.00	3.10	6.40	7.40
	22-6	21.54	4.65	0.00	3.10	6.40	7.40
March – May	19-22	21.70	4.80	0.00	3.10	6.40	7.40
	7-18	21.26	4.36	0.00	3.10	6.40	7.40
	23-6	20.25	3.35	0.00	3.10	6.40	7.40
June –Aug	15-18	52.50	4.59	31.01	3.10	6.40	7.40
	19-22	20.61	3.71	0.00	3.10	6.40	7.40
	23-14	19.67	2.77	0.00	3.10	6.40	7.40

3x3 TOU with Time-Varying Energy, Capacity, & Transmission (ECT_3x3)

TOU		Prices (Cents/kWh)					
Season Months	Period Hours	Total	Energy	Capacity	Trans	Dist	Other
September – February	16-19	39.11	6.82	4.65	13.83	6.40	7.40
	7-15	19.88	5.81	0.00	0.27	6.40	7.40
	20-6	19.25	5.11	0.00	0.34	6.40	7.40
March – May	17-20	32.38	4.68	0.00	13.90	6.40	7.40
	7-16	18.44	4.38	0.00	0.26	6.40	7.40
	21-6	17.50	3.70	0.00	0.00	6.40	7.40
June –Aug	15-18	65.56	4.59	31.01	16.16	6.40	7.40
	19-22	17.51	3.71	0.00	0.00	6.40	7.40
	23-14	16.57	2.77	0.00	0.00	6.40	7.40

3x3 TOU with Time-Varying Energy, Capacity, Transmission, & Distrib. (ECT_3x3)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
September – February	**17-20**	37.63	6.73	4.03	13.73	5.74	7.40
	8-16	17.07	5.80	0.00	0.42	3.45	7.40
	21-7	14.17	4.99	0.00	0.00	1.78	7.40
March – May	**17-20**	28.31	5.53	0.00	11.53	3.85	7.40
	8-16	13.86	4.23	0.00	0.00	2.24	7.40
	21-7	13.17	3.67	0.00	0.75	1.35	7.40
June – August	**15-18**	97.53	4.78	32.11	16.83	36.42	7.40
	19-22	27.59	3.91	0.00	0.00	16.28	7.40
	23-14	17.01	2.86	0.00	0.00	6.74	7.40

4x4 TOU with Time-Varying Energy (E_4x4)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
January – February	**18-20**	30.16	10.96	2.30	3.10	6.40	7.40
	7-17	27.99	8.79	2.30	3.10	6.40	7.40
	21-23	27.63	8.43	2.30	3.10	6.40	7.40
	24-6	26.10	6.90	2.30	3.10	6.40	7.40
November – December	**17-19**	25.39	6.19	2.30	3.10	6.40	7.40
	20-22	24.16	4.96	2.30	3.10	6.40	7.40
	7-16	23.78	4.58	2.30	3.10	6.40	7.40
	23-6	22.86	3.66	2.30	3.10	6.40	7.40
March – April	**18-22**	24.65	5.45	2.30	3.10	6.40	7.40
	7-13	24.48	5.28	2.30	3.10	6.40	7.40
	14-17	23.57	4.37	2.30	3.10	6.40	7.40
	23-6	23.08	3.88	2.30	3.10	6.40	7.40
May – October	**12-21**	23.21	4.01	2.30	3.10	6.40	7.40
	8-11	22.16	2.96	2.30	3.10	6.40	7.40
	22-24	21.98	2.78	2.30	3.10	6.40	7.40
	1-7	21.37	2.17	2.30	3.10	6.40	7.40

4x4 TOU with Time-Varying Energy & Capacity (EC_4x4)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
January – February	**18-20**	27.86	10.96	0.00	3.10	6.40	7.40
	7-17	25.69	8.79	0.00	3.10	6.40	7.40
	21-23	25.33	8.43	0.00	3.10	6.40	7.40
	24-6	23.80	6.90	0.00	3.10	6.40	7.40
March – June	**17-21**	26.44	4.39	5.14	3.10	6.40	7.40
	7-16	20.90	4.00	0.00	3.10	6.40	7.40
	22-24	20.35	3.45	0.00	3.10	6.40	7.40
	1-6	19.80	2.90	0.00	3.10	6.40	7.40
July – August	**15-17**	66.76	4.89	44.97	3.10	6.40	7.40
	18-22	21.03	4.13	0.00	3.10	6.40	7.40
	10-14	20.72	3.82	0.00	3.10	6.40	7.40
	23-9	19.26	2.36	0.00	3.10	6.40	7.40
May – October	**16-20**	27.55	5.06	5.59	3.10	6.40	7.40
	7-15	20.95	4.05	0.00	3.10	6.40	7.40
	21-23	20.78	3.88	0.00	3.10	6.40	7.40
	24-6	19.87	2.96	0.00	3.10	6.40	7.40

4x4 TOU with Time-Varying Energy, Capacity, & Transmission (ECT_4x4)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
January – February	**18-20**	42.59	10.96	0.00	17.83	6.40	7.40
	7-17	22.59	8.79	0.00	0.00	6.40	7.40
	21-23	22.23	8.43	0.00	0.00	6.40	7.40
	24-6	20.70	6.90	0.00	0.00	6.40	7.40
October – December	**18-20**	34.32	5.68	0.00	14.84	6.40	7.40
	21-2	18.85	3.81	0.00	1.24	6.40	7.40
	7-17	18.12	4.32	0.00	0.00	6.40	7.40
	3-6	16.97	3.17	0.00	0.00	6.40	7.40
March – May	**18-20**	35.32	4.86	0.00	16.66	6.40	7.40
	7-17	18.78	4.35	0.00	0.63	6.40	7.40
	21-23	18.12	4.31	0.00	0.00	6.40	7.40
	24-6	17.08	3.28	0.00	0.00	6.40	7.40
May – October	**15-17**	82.22	4.55	42.23	21.64	6.40	7.40
	18-21	18.96	4.10	0.00	1.06	6.40	7.40
	10-14	17.40	3.60	0.00	0.00	6.40	7.40
	22-9	16.22	2.42	0.00	0.00	6.40	7.40

4x4 TOU with Time-Varying Energy, Capacity, Transmission, & Distrib. (ECT_4x4)

TOU		Prices (Cents/kWh)					
Season Months	**Period Hours**	**Total**	**Energy**	**Capacity**	**Trans**	**Dist**	**Other**
December – March	**18-20**	38.85	8.15	0.00	17.82	5.49	7.40
	7-17	17.10	6.63	0.00	0.00	3.08	7.40
	21-23	16.79	6.41	0.00	0.00	2.98	7.40
	24-6	13.64	5.19	0.00	0.00	1.05	7.40
May – June	**17-19**	54.13	3.46	17.50	17.45	8.33	7.40
	14-16	21.39	3.35	0.00	3.87	6.78	7.40
	20-22	14.66	3.12	0.00	0.00	4.14	7.40
	23-13	11.52	2.43	0.00	0.00	1.69	7.40
July – August	**15-17**	119.71	4.89	44.97	18.82	43.63	7.40
	18-21	40.61	4.33	0.00	1.85	27.02	7.40
	12-14	34.47	4.15	0.00	0.00	22.92	7.40
	22-11	14.14	2.59	0.00	0.00	4.15	7.40
September – November	**16-19**	42.47	4.56	10.12	12.95	7.43	7.40
	9-15	16.13	3.69	0.00	0.77	4.27	7.40
	20-22	15.63	4.00	0.00	0.00	4.24	7.40
	23-8	12.17	2.83	0.00	0.94	1.00	7.40

Appendix B: EV Charging Routine

This appendix describes the linear program used to determine optimal EV charging, based on EV characteristics and market prices. The linear program is adapted from a model previously employed by the author to assess the impact of retail rate design on energy storage dispatch.[20] The linear program was developed using the standard Python 3.8 scientific stack, Pyomo optimization library[21], and was solved using GLPK.[22]

Objective Function ($)

Conceptually, the objective function of this program seeks to minimize EV charging costs across the study period (Term 1), where **T** is the set of time (in hours), **I** is the nominal quantity of injected into the battery in each time period t, **P** is the marginal price of energy (based on the retail rate), and η is the one-way efficiency of the battery (set to $\sqrt{85\%}$).

There are two penalty functions included in the objective: one to encourage flatter charging (Term 2) and one to encourage a fuller battery (Term 3). The I_{max} value in the first penalty function represents a short-run, rolling maximum injection rate and the SOC_{max} value in the second penalty function reflects the maximum short-run state of charge. These terms are discussed below. The penalty rate, δ, is set at $0.0001/MWh and provides a very slight incentive to reduce the rate of charging and increase the battery's state of charge. This value is small enough, however, for it to be easily "overridden" by more meaningful price signals.

$$min \sum_{t=0}^{T} \left(\frac{I_t}{\eta} \times P_{,t}\right) + \sum_{t=0}^{T} \left(I_{Max,t} \times \delta\right) - \sum_{t=0}^{T} \left(SOC_{Max,t} \times \delta\right) \tag{1}$$

State of Charge

SOC measures how "full" a battery is at a given point in time. SOC in each period t must equal the SOC at the beginning of the prior period plus injections less withdrawals in that prior period. SOC ranges from zero to the SOC_{max} of 75 kWh.

$$0 \leq \ SOC_t \leq SOC_{max} \tag{2}$$

$$SOC_t = SOC_{t-1} + I_{t-1} + W_{t-1} \tag{3}$$

[20] Cf. B.W.Griffiths (2019) "Reducing emissions from consumer energy storage using retail rate design". *Energy Policy,* vol. 129, 481-490. https://doi.org/10.1016/j.enpol.2019.01.039.

[21] Pyomo: Hart, William E., Carl D. Laird, Jean-Paul Watson, David L. Woodruff, Gabriel A. Hackebeil, Bethany L. Nicholson, and John D. Siirola. Pyomo – Optimization Modeling in Python. Second Edition. Vol. 67. Springer, 2017. Hart, William E., Jean-Paul Watson, and David L. Woodruff. "Pyomo: modeling and solving mathematical programs in Python." Mathematical Programming Computation 3(3) (2011): 219-260.

[22] Solver: GNU Linear Programming Kit (GLPK), https://www.gnu.org/software/glpk/glpk.html.

Injection & Withdrawal

The quantity of energy injected into the battery, or withdrawn from it, depends on the time of day. For simplicity all driving (and battery discharge) is assumed to occur at 2PM. Because the car has an assumed efficiency 0.24 kWh/mile and is assumed to drive 41 miles per day, energy withdrawal equals 9.94 kWh in this hour.

Further, the EV is assumed to be plugged into the charger only in evening hours (from 6PM to 8AM) so in other hours the charge rate is set to zero. In other hours, energy may be Injected into the battery at any value between zero and an exogenous maximum charge rate (11.5 kW/hour). This is in line with most Tesla EVs. Thus, charging and discharging can be described using the system of conditional equations:

$$\begin{aligned} &\textit{If}\ \mathrm{t} = \mathrm{2PM}: && (4)\\ &\quad \textit{Then}\ W_{\mathrm{t}} = -9.94\ kWh &&\\ &\textit{If}\ \ (\mathrm{t} < \mathrm{T}_{arrives\ home})\ \mathrm{or}\ (\mathrm{t} > \mathrm{T}_{leaves\ home}): && (5)\\ &\quad \textit{Then}\ \mathrm{I}_{\mathrm{t}} = 0\ kWh &&\\ &\textit{Else}: && (6)\\ &\qquad 0 \leq\ \mathrm{I}_{\mathrm{t}} \leq \mathrm{ESS}_{\mathrm{Charge\ Rate}} && \end{aligned}$$

Penalty Functions

For ESS on a flat energy rate, I add two penalty functions to encourage flatter charging and fully battery charge levels. The penalty functions are embedded in Equation 1. $I_{Max,t}$ and $SOC_{Max,t}$ are as indexed, rolling values which reflect the maximum quantity of consumption (or SOC) in each of the hours of the rolling period. More specifically, the variable $I_{Max,t}$ is constrained using Equation 7 and $SOC_{Max,t}$ is constrained using Equation 8.

$$I_{Max,t}\ \geq I_{offset}\ \ \forall \in Offsets \qquad (7)$$
$$SOC_{Max,t} \geq SOC_{offset}\ \ \forall \in Offsets \qquad (8)$$

Where $Offsets$ is a set of time-offsets before time T (1, 3, 6, and 9 hours)

In effect, each I_{Max} is the maximum of the quantity of injected energy one hour previously, 3 hours, previously, 6 hours previously, and 9 hours previously. This set of offsets offer a reasonable trade-off between computation speed and precision. Experientially, more offsets materially slow down the but do not materially change resulting “flatness” of charging or fullness of the battery.