Attachment ERN-1

Education and Professional Background

Elizabeth R. Nixon

My name is Elizabeth R. Nixon. I am employed as a Utility Analyst with the New Hampshire Department of Energy (DOE). My business address is 21 S. Fruit St., Suite 10, Concord, NH 03301.

I earned a B.S. in Mathematics from the University of Vermont in 1985. I worked for ICF, a consulting firm, where we estimated, modeled, and analyzed the energy, environmental and economic impacts of various emission reduction strategies at electric utilities. At ICF and AER*X, Inc., I assisted companies in implementing market-based emissions trading programs. I provided comments on various air quality programs affecting the electric utilities and other industries in the Northeast and other states. I also worked for the Center for Clean Air Policy where we coordinated a dialogue of states and electric utilities to discuss energy efficiency and other emission control strategies to reduce acid rain and greenhouse gases at electric utilities.

At the New Hampshire Department of Environmental Services, I wrote the air quality permits for Eversource's electric generating facilities as well as other electric generating facilities and manufacturing facilities in NH. I testified before the NH Air Resources Council regarding the determination of the baseline mercury emissions for Eversource's coal-fired electric generating facilities.

I joined the New Hampshire Public Utilities Commission, which is now DOE, in August 2012. I started in the Sustainable Energy Division where I managed renewable energy incentive programs, determined compliance with the renewable portfolio standard (RPS) program, and conducted analysis of and provided testimony and presentations on the RPS program and rebate programs. In August 2016, I joined the Electric Division. I completed electric utility rate training at New Mexico State University's Center for Public Utilities. As of July 1, 2021, I am a Utility Analyst in the Regulatory Support Division at DOE.

I have testified in the energy efficiency program docket (DE 17-136) and Liberty's battery storage pilot docket (DE 17-189). In addition, I have provided Staff recommendations in the grid modernization docket (IR 15-296) and electric vehicle rate design docket (IR 20-004).

BEFORE THE

PUBLIC UTILITES COMMISSION OF NEW HAMPSHIRE

Docket No. DE 20-170

IN THE MATTER OF: Electric Distribution Utilities

Electric Vehicle Time of Use Rates

DIRECT TESTIMONY

OF

SANEM I. SERGICI

October 13, 2021

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LIST OF ATTACHMENTS

BEFORE THE

PUBLIC UTILITIES COMMISSION OF NEW HAMPSHIRE

I. Statement of Qualifications

Q1. Please state your name, position, and business address.

A1: My name is Sanem Sergici, I am a Principal with The Brattle Group in the Boston office, located at One Beacon Street, Boston, Massachusetts 02108.

Q2. Please describe your professional experience and educational background.

A2: I am an energy economist with sixteen years of consulting and research experience. My consulting practice is focused on understanding customer adoption of and response to innovative rate designs and emerging technologies. I regularly assist my clients on matters related to retail rate design, big data analytics, electrification, grid modernization investments, resource planning, and alternative ratemaking mechanisms. A statement of my qualifications is included in Attachment No. SIS-1.

Q3. Have you previously filed testimony before the New Hampshire Public Utilities Commission (PUC)?

A3: Yes, I have in Docket Nos DE 19-057 and DE 19-064.

II. Purpose of Testimony

Q4. On whose behalf are you testifying?

A4: I am testifying on behalf of the New Hampshire Department of Energy (Energy) Staff.

Q5. What is the purpose of your testimony?

A5: The purpose of my testimony is to comment on the Residential electric vehicle (EV) time of use (TOU) rate designs and alternative rate design proposals for high-demand draw public EV charging facilities, proposed by Eversource, Liberty, and Unitil.

Q6. Please summarize your findings and recommendations related to design of the EV TOU rates.

A6: Key findings of my analyses and my recommendations are as follows:

- I recommend that all three utilities propose an EV TOU alternative to current demand charge based rates for high-demand draw commercial EV charging applications. In the absence of demand charges, TOU rate is more consistent with the marginal cost principles, while minimizing cross subsidies.
- Utilities' arguments of commercial EV charging applications not being ideal for TOU rates are not warranted. Unless utilities design rates reflecting efficient and marginal cost-based price signals, market participants will not respond with innovation.
- The State of NH does not have an official transportation electrification public policy goal, therefore there is no public policy basis for creating cross-subsidies in the rate design for commercial charging applications at this time.
- Given that Eversource is not able to implement a three period EV TOU rate for its residential customers at this time, the two-period domestic TOU rate will be the transitional rate for these customers. A seasonally differentiated two-period rate with a shorter peak window that reflects the marginal facility costs and a lower customer charge will provide stronger price signals and is more likely to be attractive to customers both with and without EVs.
- Eversource's proposed high draw demand alternative rate to demand charges is revenue neutral at the 10% station utilization level for which it was designed. While this rate is designed to recover at least a portion of demand related revenues in the form of volumetric charges, it will still lead to cross-subsidies. Moreover, this rate does not provide marginal cost based price signals for a more efficient use of system assets. I recommend that Eversource designs an EV TOU rate as an alternative to demand charges, using the approach utilized in the design of Energy's illustrative EV TOU rate for Eversource.
- Liberty has not proposed a new residential EV TOU at this time as it offers a three-period seasonal rate initially offered for battery storage customers. This rate will also

be available to separately metered EV TOU customers. I recommend that Liberty revisits this rate design periodically to ensure that the time periods are still reflective of system demand conditions and lead to efficient charging behavior.

- Liberty's proposed high-draw demand alternative to demand charges is a revenue neutral volumetric rate that reduces most of the charges collected from demand charges, but not all of them. This rate, however, does not provide price signals that will incentivize a more efficient use of the system assets. I recommend that Liberty designs an EV TOU rate as an alternative to demand charges, using the approach utilized in the design of Energy's illustrative EV TOU rate for Liberty.
- While Unitil's residential EV TOU rate design is generally consistent with the guidance issued by the Commission on the ideal attributes of the EV TOU rates, the distribution component of the rate is "imposed" to achieve a 3:1 peak to offpeak ratio. Unitil should derive the distribution cost component of this rate in such a way that it assigns the costs of the system assets to those hours driving the need for those assets. Unitil should also evaluate whether it will incur additional costs resulting from customers' charging their EVs at home, in addition to the incremental costs associated with the meters.
- Unitil has proposed an EV TOU rate for high-demand draw applications, which introduces time varying rates for the generation and transmission components of this rate. However, Unitil's proposed rate still maintains the original demand charge component and proposes a three year demand charge holiday. These cross subsidies for the commercial charging facilities through rate design are not warranted given that increased transportation electrification is not an official public policy goal in New Hampshire. I recommend that Unitil designs an EV TOU rate as an alternative to demand charges, using the approach utilized in the design of Energy's illustrative EV TOU rate for Unitil.

Q7. Please summarize your recommendations related to implementation of EV TOU rates.

A7: My recommendations related to the implementation of the EV TOU rates are as follows:

- I recommend that the Commission direct all three utilities to offer a customer-contributed option for the additional meter.
- I recommend that the Commission direct those utilities which have not provided a marketing plan to develop a marketing plan.
- I recommend that the Commission direct those utilities which have not proposed an alternative metering feasibility pilot to develop such a pilot.
- I recommend that the Commission require annual reports from the utilities regarding the rates and pilots at issue in this proceeding.

Q8. How is your testimony organized?

A8: Section III describes the established principles of rate design and sets the foundation for my assessment of utilities' EV TOU and alternative rate design proposals for public EV charging stations. Section IV presents my assessment of Eversource's proposed rates; Section V presents my assessment of Liberty's proposed rates; and Section VI presents my assessment of Unitil's proposed rates. Section VII concludes my testimony.

III. Principles of Rate Design

Q9. Please describe the principles of rate design that you used to review the proposed rate design.

A9: Widely accepted principles of rate design were outlined in the various editions of James C. Bonbright's *Principles of Public Utility Rates*.[1] These can be condensed into five core principles:

1. *Economic Efficiency*—The price of electricity should convey to the customer the cost of producing it, ensuring that resources consumed in the production and delivery of electricity are not wasted. If the price is set equal to the cost of providing a kilowatt hour (kWh), customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the adoption and use of energy technologies in a way that provides the most value to the grid, and therefore the greatest benefit to electric customers as a whole.

2. *Equity*—There should be no subsidies between customer types. Each class should pay for their contribution to the cost of service, not more and not less.

3. *Revenue Adequacy and Stability*—Rates should recover the authorized revenues of the utility and should promote revenue stability. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost-reflective.

4. *Bill Stability*—Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time.

5. *Customer Satisfaction*—Rates should enhance customer satisfaction. Rates need to be relatively simple so that customers can understand them and respond to the rates

[1] James C. Bonbright, Principles of Public Utility Rates, (Columbia University Press: 1961) 1st Edition.

by modifying their energy use patterns. Giving customers meaningful cost reflective rate choices helps enhance customer satisfaction.

Q10. Is there an overriding principle among these well-established rate design principles?

A10: Yes, it is the principle of cost causation. What this means is that the rates should reflect the underlying costs incurred to serve customers or load. Ideally, fixed costs should be recovered through a fixed monthly charge, capacity costs through a demand charge, and energy costs through an energy (volumetric charge). While there might be technical (*e.g.*, lack of advanced metering infrastructure) and practical (*e.g.*, customer acceptability) constraints that might prevent the implementation of purely cost reflective rates, it is advisable to stay true to cost-reflective rates as much as possible.

Q11. Did the Commission issue specific guidance on the rate design standards for electric vehicle charging stations? Please summarize.

A11: Yes, the Commission has provided the following guidance through Order No. 26,394 on the electric vehicle rate design standards:[2]

i- Electric vehicle charging rate design shall reflect the marginal cost of providing electric vehicle charging services to the maximum extent practicable, provided that these rates will be updated and reconciled on a regular basis to ensure they reflect costs associated with customer usage patterns.

ii- Declining block rates shall not be used for electric vehicle charging for separately metered electric vehicle supply equipment (EVSE).

iii- Seasonal rates may be charged for electric vehicle charging to account for the seasonality of winter and summer cost drivers on the electric system.

iv- Interruptible rates are not appropriate for electric vehicle charging.

[2] State of New Hampshire Public Utilities Commission, IR 20-004, Order No. 26,394 Determining the Appropriateness of Rate Design Standards for Electric Vehicle Charging Stations Pursuant to SB 575.

v- Load management offerings may be an appropriate strategy for electric vehicle rate design, especially when offered in conjunction with electric vehicle time of use rate offerings.

vi- Demand charges may be an appropriate rate design for high demand draw EVSE, but not for residential charging applications. Demand charges may limit the economic viability of low utilization rate, high demand draw EVSE, but also limit cost shifts between classes and customers. Utilities shall consider demand charge alternatives in any high demand draw rate design proposals they may develop.

vii- Time of use rates are appropriate for electric vehicle charging, and required the utilities to file: (1) an EV TOU rate proposal for separately-metered residential and small commercial customer applications; and (2) an EV TOU rate proposal for separately-metered high demand draw commercial customer applications that may incorporate direct current fast charging or clustered level two chargers.

Q12. Do you agree with the Commission's guidance on the rate design standards for electric vehicle charging stations?

A12: Yes, I do. I understand that the Commission instructed utilities to propose demand charge alternatives to assist with the economic viability of charging stations, while staying as close as possible to the marginal cost principles. While there are other alternatives that could help improve the viability of low utilization charging stations, EV TOU rates would be better aligned with the marginal cost principles. Charging stations may in turn develop pricing strategies in the form of time-based rates to pass on these pricing signals to their customers. This approach is currently being implemented by a few charging companies across the country.[3] They may also pursue other strategies such as installation of load control equipment and solar and storage systems.

[3] Fred Lambert, "Tesla introduces new 50% Supercharging discount at night in California to help with capacity," *electrek*, April 5, 2021 at https://electrek.co/2021/04/05/tesla-isupercharging-discount-night-california-help-capacity/

Q13. What is your recommendation regarding an alternative rate for separately-metered high-demand draw commercial customer applications?

A13: I recommend that utilities propose an EV TOU alternative to current demand charge based rates for high demand draw commercial customer applications. In the absence of demand charges, this rate is more consistent with the marginal cost principles, while minimizing cross subsidies. At a minimum, utilities might consider removing the demand charges, and spreading the demand charge related cost recovery on the volumetric sales. While this is not the preferred approach, it does not create explicit subsidies such as those created by demand charge holidays and other variations, which stop (often times temporarily) the recovery of the costs originally collected by demand charges.

Q14. Did the Commission provide more specific guidance on the recommended parameters for any separately-metered residential electric vehicle charging rate?

A14: Yes, in Docket No. DE 20-004 the Commission Staff recommended the following: "1) be based directly on cost causation; (2) incorporate time varying energy supply, transmission, and distribution components; (3) have three periods (e.g., off-peak, mid-peak, and peak); (4) be seasonably differentiated (e.g., summer and winter); (5) have an average price differential between off-peak and peak of no less than 3:1; and (6) have a peak period no longer than four hours in duration."[4] The Commission adopted the Staff guidelines as "useful starting points" in EV TOU rate designs, with two clarifications. The Commission clarified that a five-hour peak duration is more appropriate than the four-hour peak duration, and that the 3:1 ratio should be an annual average differential.[5]

[4] Order 26,394, page 15-17.
[5] *Id*.

Q15. Do you agree with the "useful starting points" as proposed by the Commission?

A15: In general, yes. An effective rate design conveys price signals that are transparent and actionable, giving customers the necessary information and a strong incentive to shift their charging load away from the utility's system peak hours to designated offpeak periods. Currently, roughly 80% of the light-duty vehicle charging takes place at home and this trend is expected to continue in the near future.[6] Moreover, EVs can be easily programmed through the car and/or the charger to begin charging at a pre-set time. Therefore, it is important to design residential EV TOU rates that provide strong price signals for offpeak charging, and are also appeal to the customers for their participation in these rates.

A recent SEPA/Brattle survey has identified the attributes of "successful" EV TOU rates, where success is defined as a high enrollment rate or significant load shifting to offpeak periods. Based on the 28 survey respondents (out of 50 contacted), the price ratios of the rates ranged from 1.2:1 to 15.5:1, with a median of 3.6:1. Survey participants reported that "despite potential savings, some customers are deterred by the initial enrollment fees for the installation of additional metering equipment."[7] Another Brattle survey of 27 EV TOU rates reported a median peak period duration of 5 hours during the Summer months versus 8 hours during the Winter months.[8]

These observations lend support to Commission's guidance on "useful starting points," although some deviations from these parameters might be reasonable provided that they are justified by underlying system cost and load structures for each utility.

[6] John Voelcker, "JD Power Study: Electric Vehicle Owners Prefer Dedicated Home Charging Stations," *Forbes wheels*, February 5, 2021 at https://www.forbes.com/wheels/news/jd-power-study-electric-vehicle-owners-prefer-dedicated-home-charging-stations/

[7] SEPA, "Residential Electric Vehicle Rates That Work: Attributes That Increase Adoption," November 2019.

[8] Ahmad Faruqui, *et al.*, The State of Electric Vehicle Home Charging Rates: A Summary, presented to Colorado PUC, October 15, 2018 at http://files.brattle.com/files/14717_the_state_of_residential_ev_electric_rates_10-15-2018.pdf

IV. Assessment of Eversource Residential EV TOU Rates and High Demand Draw Alternative

Q16. Please describe your understanding of how Eversource developed their residential EV TOU rates.

A16: Eversource proposed a residential EV TOU rate, "Rate R-EV" that is separately metered but connected to the same service as the primary residence. The proposed rate is revenue neutral to the residential rate "Rate R" and was developed assuming an average residential customer load profile.

The rate has three TOU periods: peak, midpeak, and offpeak. A five-hour peak period commences at 2 p.m. and ends at 7 p.m. for all weekdays except holidays; a midpeak begins at 7 a.m. and ends at 11 p.m. each day, except for peak period hours; and all other hours are offpeak. The three periods are established based on the timing and the duration of marginal costs within each service component (generation, transmission, and distribution).

Time periods are non-seasonal and defined based on annual averages of marginal cost, despite the Commission's guidance to establish seasonality. The proposed rate follows the Commission's other guidance in that it establishes a maximum five-hour peak period and attains an annual average of 3.07:1 peak/offpeak ratio before the other flat charges are included and 2.7:1 peak/offpeak ratio after the other charges are accounted for (see Table 1).

TABLE 1: PROPOSED RESIDENTIAL EV TOU RATE ($ PER KWH)

	Generation ($/kWh)	Transmission ($/kWh)	Distribution ($/kWh)	Other Charges ($/kWh)	**Total ($/kWh)**
Peak	$0.103	$0.087	$0.064	$0.016	**$0.271**
Midpeak	$0.062	$0.021	$0.060	$0.016	**$0.159**
Offpeak	$0.050	$0.012	$0.021	$0.016	**$0.099**

	Peak :Offpeak
Ratio	2.7 :1

Note: Other charges include SCRC, SBC, and other volumetric charges. Customer charge is $16.50 per month.

For each service component, TOU rates are determined by adjusting the revenue target for the marginal cost differences between the time periods. Marginal costs are allocated on an hourly basis over the course of the year, using a proprietary model determining each hour's expected probability of being the annual peak for each service component. These hourly marginal costs are then assigned to TOU periods by averaging them by period. Charges for each service component are obtained as the following:

- **Distribution**: Hourly marginal distribution costs are obtained from the 2019/20 marginal cost of service (MCOS) study, which yielded monthly marginal costs due to customers, local distribution facilities, and distribution substation costs. These costs are then annualized and adjusted for 2021 dollars. The allocation of the annualized distribution cost to hours is based on each hour's expected probability of being the annual peak at the distribution substation level, using hourly load from 2015 through 2018.
- **Transmission**: The Company's ISO-NE monthly Regional Networks Service (RNS) rate ($/kW-year) is allocated to each hour, based on the probability that each hour will be that month's peak hour in the transmission system.
- **Generation**: Hourly marginal costs are obtained based on hourly ISO-NE locational marginal prices (LMPs), forward capacity market (FCM) capacity prices (based on probability of peak analysis to allocate yearly price to hours), marginal losses, Renewable Portfolio Standard (RPS) costs, energy and RPS reconciliation factors, and working capital expenses.

Q17. Please describe how Eversource calculated the customer charge for the residential EV TOU rates.

A17: The customer charge for the residential EV TOU rates is $16.5 per month. This is reduced compared to the customer charge of $32.08 per month of the current residential time of day rate (R-OTOD), because local facilities cost is removed from the customer charge and built into the TOU volumetric prices in the peak and midpeak periods. If a customer charges an EV during offpeak hours, they would not be charged for the local facilities costs. This is intended to signal the need for increased local capacity during midpeak or peak periods.

Q18. Did Eversource propose a plan for exploring EVSE embedded metering capabilities that could mitigate the second meter costs necessary to implement separately metered EV TOU rates?

A18: No, not at this time. I understand that the Commission has expressed an interest for utilities to further explore EVSE embedded metering capabilities that could potentially increase the adoption of EV TOU rates by mitigating the additional meter costs.[9] I encourage the Company to design a pilot/demonstration program to understand the technical feasibility of this option.

Q19. What is your assessment of Eversource's proposed EV TOU rate?

A19: I found that the design of the Eversource EV TOU rate is generally consistent with the well-established marginal cost-based rate design principles. Number of periods, length of the peak and super-offpeak periods are designed in a way to incentivize efficient charging behavior consistent with the system marginal cost signals. These price signals can be further improved if the rates are differentiated by season reflecting seasonal considerations in the allocation of generation, transmission, and distribution costs. EV customers charging their EVs under this rate structure will observe cost savings if they are able to shift their charging load to the offpeak period. This in turn will help reduce current and future system costs.

Unfortunately, it is my understanding that Eversource does not recommend implementation of this rate at this time.

Q20. Why is the Company unable to implement this rate at this time?

A20: While the Company submitted the proposed rate described above in Docket No. DE 20-170, the Company does not recommend near-term implementation of a separately metered EV TOU rate due to substantial modification needed to enterprise-wide

[9] Order 26, 394, page 13.

MDMS and CIS systems. Eversource projects $9 million of costs would be associated with the upgrade necessary to offer either a three period rate or a time of use generation component. Eversource projects that, after the future conversion of the enterprise systems, cost associated with offering either a three period rate or time-varying generation would still be approximately $5 million.[10] Eversource is also planning to update all of its customer systems over the next three-four years as a result of a recent order in Massachusetts directing them to develop a timeline for AMI deployment.[11]

Q21. Please describe the Company's existing customer billing system and time of use rate offerings.

A21: As a basis for its recommendation against its time-varying *generation* rate, Eversource states that it "utilizes one legacy customer billing system across three states" and cites $9 million of costs relating to "regression testing to ensure no impact to other state jurisdictions with this change."[12] However, the Company's Connecticut affiliate already offers a two period time-varying rate that includes a time-varying generation component for residential customers,[13] small general service customers,[14] a small general service customer alternative rate that appears to be the Company's Connecticut electric vehicle demand charge alternative,[15] intermediate general service customers,[16] and large general service customers.[17] Given that the Company utilizes one legacy customer billing system across three states, and given that the Company's Connecticut

[10] Attachment SIS-2 (Eversource Response to Request Energy 2-019). *See* also Attachment SIS-3 (Eversource Response to Request Energy 3-008, Attachment 1).

[11] Joint Testimony of Dennis E. Moore, Brian J. Rice and Michael R. Goldman, Docket No. DE 20-170, page 11.

[12] Attachment SIS-4 (Eversource Response to Request Energy 3-001).

[13] Connecticut Light and Power. Rate 7. https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/rate-7-ct.pdf?sfvrsn=8224c062_24

[14] Connecticut Light and Power. Rate 27. https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/rate-27-ct.pdf?sfvrsn=7d24c062_26

[15] Connecticut Light and Power. Rate 27a. https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/rate-27a-ct.pdf?sfvrsn=b600a362_4

[16] Connecticut Light and Power. Rate 37. https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/rate-37-ct.pdf?sfvrsn=a24c062_24

[17] Connecticut Light and Power. Rate 58. https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/rate-58-ct.pdf?sfvrsn=e441c762_48

affiliate clearly has the ability to offer a two period time varying rate with a time varying generation component, it seems that the Eversource should be able to offer a two period time-varying generation component to New Hampshire ratepayers. I have structured the remainder of my testimony under this assumption.

Q22. What is your recommendation if the Company is unable to offer a time-varying generation component?

A22: If for some reason the Company is unable to provide such an offering, I recommend that the Commission direct the Company to conduct an RFP process to seek third parties who can provide three period time of use rates, inclusive of a time varying generation component, as a service to the Company on a pilot basis for separately metered electric vehicle customers. The RFP could be structured so that the metering and billing occurs independent of the Company's legacy systems and could utilize the metering technology embedded in most chargers. This approach has the potential to avoid costly upgrades to legacy systems. The RFP process should be stakeholder inclusive, and the Department of Energy and other interested stakeholders should have an opportunity to weigh in on responding proposals before the Commission.

Q23. Does Eversource offer any other residential TOU rate that might be available to EV customers?

A23: Yes. Eversource has proposed a new residential time-of-use rate in DE 21-119.[18] This rate has two periods including a seven hour peak period (noon -7 p.m.) during non-holiday weekdays and offpeak hours, covering all other hours. Eversource's proposed rate is reproduced in Table 2 below.

[18] Eversource's testimony also set forth a load management proposal as an alternative to time of use rates. I do not address this proposal in my testimony because load management proposals were not a noticed issue in this proceeding and are currently a matter pending Commission decision in DE 20-092. See, DE 20-092, December 21, 2020 Transcript at page 139, lines 8-15. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092/TRANSCRIPTS-OFFICIAL%20EXHIBITS-CLERKS%20REPORT/20-092_2021-01-06_TRANSCRIPT_12-21-20.PDF

TABLE 2: PROPOSED R-OTOD-2 RATE ($/KWH)

	Generation ($/kWh)	Transmission ($/kWh)	Distribution ($/kWh)	Other Charges ($/kWh)	**Total ($/kWh)**
Peak	$0.066	$0.074	$0.028	$0.020	**$0.188**
Offpeak	$0.066	$0.017	$0.023	$0.020	**$0.126**

	Peak	**:Offpeak**
Ratio	1.5	:1

Note: Other charges include SCRC and SBC. Customer charge is $32.08 per month.

In addition to the variable charges reported in Table 2, this rate also involves a customer charge of $32.08 per month, which is more than twice Eversource's residential customer charge of $13.81.

Q24. What is your assessment of Eversource's two period residential TOU rate?

A24: While this newly proposed residential TOU rate is an improvement over Eversource's existing TOU rate, which includes an 11-hour peak period, there is still room for improvement to make this rate better aligned with marginal cost signals and more attractive for the customers. More specifically:

- The peak to offpeak (P/OP) ratio purely based on the time-varying components of the rate (distribution and transmission) is 2.6. However, when other variable charges in the rate design are included to create an "all-in variable" charge for both peak and offpeak rates, the peak to offpeak ratio becomes 1.5. Prior Brattle research has shown that the P/OP ratios below 2 will not sufficiently incentivize customers to change their consumption patterns and a ratio of at least 3 is ideal to incentivize customers and provide reasonable bill saving opportunities.[19]

[19] Nova Scotia Power Time-Varying Pricing Project Submission to Nova Scotia Utility and Review Board, June 30, 2020. https://brattlefiles.blob.core.windows.net/files/19479_nova_scotia_utility_and_review_board_-_time-varying_pricing_project_submission.pdf

- A peak period of seven consecutive hours is typically considered long from a customer experience point of view. Given that this rate will apply to the whole house load, customers may find it difficult to shift their usage for the seven hour period, impacting their willingness to sign up for this rate. Reducing peak period duration to five hours might be ideal, which will also help with creating stronger peak period price signals as the peak period costs will now be allocated to five hours, instead of seven.[20]
- Eversource's 2019 Marginal Cost study estimated monthly marginal customer costs (including meter and service drop, customer expenses) by customer class, monthly marginal local distribution facilities costs (transformers, primary and secondary conductors) by customer class, and distribution substation costs. It is our understanding that Eversource's proposed customer charge of $32.08 includes both the marginal customer costs and marginal local distribution facilities costs. It may be reasonable to exclude the marginal local distribution facilities cost from the proposed customer charge and recover these additional costs in the distribution peak chargers. This would serve two purposes: 1) it will provide the customers with a stronger price signal during the peak period and incentivize them to reduce their peak demand; and 2) by lowering peak demand during the peak period, it will help lower future capacity needs. In fact, this approach was used by Eversource in their design of the three period EV TOU rate, where the costs of the local transformer were recovered in the volumetric rate component outside of the offpeak period in order to provide price signals that encourage offpeak (overnight) EV charging and discourage charging at times that may cause the need for additional local facilities' capacity and thereby cause incremental costs to be incurred at the individual customer level (*e.g.*, increased transformer/service requirements).[21]

[20] Ahmad Faruqui, Ryan Hledik, Sanem Sergici. "A Survey of Residential Time-Of-Use (TOU) Rates", November 12, 2019. https://www.brattle.com/wp-content/uploads/2021/05/17904_a_survey_of_residential_time-of-use_tou_rates.pdf

[21] Testimony of Edward A. Davis, Docket No. DE 20-170, page 5-6.

- Eversource's proposed two-period residential TOU rate does not include seasonal variation. Seasonal variation may improve the quality of the price signals, and more accurately attribute costs that are driven by seasonal demand elements (*i.e.*, generation capacity costs are driven by summer peak periods). I analyzed Eversource's class load profile and found that May through September are more closely clustered together and have similar load shapes compared to the other months. Therefore, May through September should be defined as the summer months for rate design purposes.
- Eversource's proposed two-period residential TOU rate does not include a time-varying generation component.

Q25. How can Eversource improve its two period residential TOU rate to provide stronger price signals to customers for load shifting and at the same time improve its attractiveness?

A25: Given that Eversource will not be able to implement its proposed three-period EV TOU rate at this time, and that the two-period TOU rate will be the transitional rate to incentivize efficient charging of the EVs, I recommend that Eversource revises its two-period residential TOU rate to account for the areas of concern listed above. A seasonally differentiated two-period rate with a shorter peak window that reflects the marginal facility costs and a lower customer charge is more likely to be attractive to customers both with and without EVs.

Q26. Does Eversource have a marketing plan in place to market EV TOU rates to its customers with electric vehicles?

A26: No, I am not aware of any formal plans and marketing budget allocated to effectively marketing EV TOU rates to customers. Increased adoption of EV TOU rates will benefit customers in the form of bill savings if they can shift their charging to offpeak periods. It will also benefit Eversource and other customers as the demand during system peak hours are moderated (due to customers shifting their charging load to offpeak periods) and avoid costly expansions. I strongly encourage the Company to develop a targeted marketing plan with the objective of increasing the uptake of the TOU rates among the EV customer population.

Q27. Please describe your understanding of how Eversource developed their high draw demand charge alternative rate design.

A27: In Docket No. DE 21-078, Eversource proposes a rate for public EV charging stations as an alternative to its Rate GV service, which it offers to customers with no more than 1,000 kW of peak demand.[22] The proposed rate is a demand-charge alternative rate design; however, it is not TOU-based as instructed by the Commission. The rate is designed for charging station utilization of up to 10%, where utilization below 10% results in lower monthly charges than would occur under Rate GV.

Rate components for the EV demand-charge alternative rate design include a customer charge and a volumetric charge. The customer charge is maintained at $211.21/month, as it is for the Rate GV class. The volumetric charge portion recovers two types of costs:

- <u>Demand charges related to distribution, transmission, and stranded cost recovery</u>. Revenue requirements for demand charges associated with distribution, transmission, and stranded cost recovery charges (SCRC) are each divided by the class's annual kWh consumption to obtain an average class rate on a $/kWh basis. These values are then multiplied by a "rate parity adjustment" which is obtained by dividing the current class average load factor (55%) by station utilization, which is assumed to be 10%.
- <u>Volumetric charges related to energy supply, system benefits charge, and remaining stranded cost recovery charges</u>. These costs are recovered from Rate-GV customers

[22] Eversource's demand charge alternative was docketed as part of DE 21-078. In the October 16, 2020 Order of Notice in DE 20-170, the Commission delineated the noticed issues in this proceeding as including "issues related to whether the EV TOU rate proposals to be developed and filed are consistent with the rate design standards delineated in Order No. 26,394." Order No. 26,394 directed the utilities to file high demand draw proposals in this proceeding that may consider demand charge alternatives. Liberty and Unitil have both filed their demand charge alternatives in this proceeding. For ease of review, and as a matter of administrative efficiency, I have chosen to present my assessment of all three demand charge alternative proposals in this proceeding.

on a $/kWh volumetric basis, therefore were not modified from their values for the Rate GV rates, which is $0.074/kWh.

Company's proposed demand-charge alternative volumetric rate is the sum of the two components described above.

Q28. Do you expect that Eversource's proposed high draw alternative to demand charges will lead to cost shifting to other customers within the class?

A28: Yes, I do. As it is currently designed, the Company's proposed rate is revenue neutral at 10% station utilization level. Below 10% utilization, the customers on this rate will pay less than their fair share of the system costs leading to a cost shift to other customers, and above 10%, if they choose to remain on this rate, will pay more than their fair share of the system costs. The Company's witness Mr. Davis acknowledges this issue in his response to DOE 2-007 (d) in DE-20-170, "…Indicatively, under the Company's proposal, lower utilization than the level applied in rate design (i.e., 10%) would produce less revenue which could represent a reduction in cost recovery compared with application of a demand charge."[23]

Q29. Did the Company also develop an EV TOU rate proposal for separately-metered high demand draw commercial customer applications, as instructed by the Commission? If not, please convey Company's reasoning.

A29: No, it did not. The Company reasons that "… the timing of public EV charging is largely non-discretionary… While a TOU rate may be introduced for these types of charging applications, the Company expects that consumers who charge their EVs at public stations would not generally be in a position to defer or otherwise schedule charging to a different time. Those who could shift charging might do so, but the design proposed here is particularly for public DCFC applications where charging is expected to occur on demand, when needed, independent of potential time-differentiated pricing alternatives."[24]

[23] Attachment SIS-5 (Eversource Response to DOE 2-007).

[24] Testimony of Edward A. Davis, Brian J. Rice and Kevin M. Boughan, Docket No. DE 21-078, page 22.

Q30. Do you agree with Company's reasoning? Please explain.

A30: No, I do not. First, it is my understanding that this Commission has a long-standing emphasis on cost-reflective rate design based on marginal costs and has instructed utilities that "…Initial electric vehicle charging rate design shall reflect the <u>marginal cost</u> of providing electric vehicle charging services to the maximum extent practicable, provided that these rates will be updated and reconciled on a regular basis to ensure they reflect costs associated with customer usage patterns."[25] In the absence of demand charges, TOU rates are the next best alternative conveying marginal price signals and providing incentives for a more efficient use of the grid for high draw customers.

Second, the Company should not second guess the abilities of its public station owners to pass on some of these efficient price signals to their own customers. When faced with a TOU rate that charges them higher rates during the peak period, the owners of the public chargers may introduce innovation into their own rate structures, and charge higher rates to their customers during peak periods. This is in fact starting to happen in California, where several Tesla stations are implementing time-varying charging rates.[26] It is possible that there are other examples. It is also possible that some of the customers using the public charging stations are not able to defer charging and in those cases, they will need to pay the higher prices because this reflects the true cost of charging their EVs during the peak period. If they do not pay this cost, other customers will have to pay for it.

Third, it is argued that if public charging stations proliferate rapidly (perhaps partially due to subsidized rates), EV adoption might increase as a result of reduced range anxiety and that increased transportation electrification may lead to potentially lower rates for all customers in the long run, as the system fixed costs will be spread over a higher level of sales (all else equal), justifying the initial subsidies. While this may be true, these subsidies are often justified by "state public policy," in which a state officially embraces "increased electrification" as part of the official state energy policy.

[25] Order No. 26,394 at 4-5.

[26] https://electrek.co/2021/04/05/tesla-isupercharging-discount-night-california-help-capacity/

In the absence of any public policy justification, subsidized rates for these public stations at the expense of other customers are not warranted.

Q31. In your opinion, are subsidized rates for public charging infrastructure warranted in New Hampshire?

A31: No, I do not believe so. New Hampshire Senate Bill 131 Part I[27] includes "findings" regarding increased availability of charging infrastructure; however, these statements are only dicta and do not indicate that a policy is in effect. SB 131 Part I findings state that the availability of electric vehicle supply equipment, and in particular DCFC along major travel corridors in the state, is critical to facilitating the deployment of electric vehicles and recommends the state to commit to the development of EV technology and infrastructure. The legislation also suggests electric distribution companies may own or fund make-ready infrastructure to accelerate EV deployment. However, this legislation does not mention subsidized rates as one of the strategies to support EV charging infrastructure. Other legislation, specifically NH RSA 236:132–136, includes statements that are generally supportive of electric vehicles; however, does not endorse any particular rate design.

In fact, subsidized rates would conflict with the Commission's guidance to avoid cross-subsidies. The Commission states that a modern distribution planning process should ensure new electrified end uses are integrated onto the grid in a manner that does not unfairly subsidize participants to the detriment of non-participating ratepayers through peak load growth.[28] Similarly, New Hampshire 10-Year State Energy Strategy[29] encourages private entities to invest in charging infrastructure by using ratepayer funding sources; however, warns against cost shifting for the sake of benefiting a small user base.

[27] New Hampshire Senate Bill 131, Part 1

[28] State of New Hampshire Public Utilities Commission, IR 15-296, Order 26,358 Guidance on Utility Distribution System Planning And Order Requiring Continued Investigation.

[29] New Hampshire 10-Year State Energy Strategy, New Hampshire Office of Strategic Initiatives. April 2018. https://www.nh.gov/osi/energy/programs/documents/2018-10-year-state-energy-strategy.pdf

Q32. Have you evaluated alternatives to demand charges for high demand draw public charging stations offered in other jurisdictions?

A32: Yes, I have. Table 3 presents my review of several jurisdictions offering demand charge alternatives for high demand draw customers. Alternatives include demand charge holidays, demand subscription rates, TOU rates, capped rates for low-utilization customers, demand limiters for low-utilization customers, demand charge credits, and lower demand charge/higher volumetric rate options for low load factor customers. Based on my review of these alternative rates for high-demand draw customers, there is not a uniform alternative used by most utilities. It is most likely that these offerings are a product of unique circumstances of each utility's regulatory and public policy environment.

TABLE 3: REVIEW OF ALTERNATIVES TO DEMAND CHARGES FOR HIGH DEMAND DRAW CUSTOMERS

Utility	Rate Schedules & kW Threshold	Components of Rate Schedule	Demand Charge Alternative & Presence of Cross Subsidy
Southern California Edison	TOU-EV-7 (< 20 kW) TOU-EV-8 (20 – 500 kW) TOU-EV-9 (>500 kW)	Customer Charge: ✓ Energy Charge: ✓ Demand Charge: × (until 2024) Time Of Use Rates: ✓	Demand Charge Holiday; Customers receiving service under this schedule will not face a Demand Charge until March 2024. Starting in 2024, the Demand Charge will be phased-in over a 5-year period.
Pacific Gas & Electric	BEV-1 (<= 100 kW) BEV-2 (>100 kW)	Customer Charge: × Energy Charge: ✓ Demand Charge: × Time of Use Rate: ✓	Replaces traditional maximum kW demand charge with subscription-based payment for customer selected monthly kW allocation. Customers incur an 'overage' fee ($/kW) if the kW usage exceeds a customer's self-designated subscription level.
Dominion Energy	Non-Demand Billing (< 200 kW) Demand Billing (> 200kW)	Customer Charge: ✓ Energy Charge: ✓ Demand Charge: ✓ (for >200 kW) Time of Use Rate: ×	Customers who face 'Demand Billing' (>200 kW) are subject to a distribution demand charge of $3.183 per kW whereas customers who face 'Non-Demand Billing' (<200 kW) have no distribution demand charge
Portland General Electric	Schedule 38 (<200 kW)	Customer Charge: ✓ Energy Charge: ✓ Demand Charge: × Time of Use Rate: ✓	TOU Rate with no demand charge for customers with demand< 200 kW; Customers face an energy TOU rate ($0.0607/kWh during the peak period; $0.0457/kWh during the offpeak period). Distribution and transmission charges are volumetric, but are not time based.

Utility	Rate Schedules & kW Threshold	Components of Rate Schedule	Demand Charge Alternative & Presence of Cross Subsidy
Duke Energy	Rate Schedule DS (<500 kW)	Customer Charge: ✓ Energy Charge: ✓ Demand Charge: ✓ Time of Use Rate: ×	Demand Charge Limit; Duke Energy calculates an initial bill based on a fixed customer charge, demand charge and energy charge and divides this initial bill by total energy consumption to derive an implied average rate in $/kWh. If this implied average rate exceeds the predetermined capped rate of $0.241/kWh, the customer's bill is calculated at the lower capped rate.
PECO Energy Company	Rate Schedules GS, PD and HT (No kW threshold)	Customer Charge: ✓ Energy Charge: ✓ Demand Charge: ✓ Time of Use Rate: ×	3-year Demand Charge Credit; PECO offers commercial EV charging facilities a credit (equal to 50 percent of the connected DCFC capacity) against any demand charges for up to 36 months. This offer is valid until 2024.
Florida Power & Light	GSD-1EV (20 kW – 499 kW) GSLD-1EV (500 kW – 2000 kW)	Customer Charge: ✓ Energy Charge: ✓ Demand Charge: ✓ Time of Use Rate: ×	Demand Limiter for Low Usage Customers; Under the tariffs, the amount of demand billed to the customer would be the lesser of measured demand or the 'limited' demand calculated by dividing the kWh sales by a fixed constant of 75 hours. Tariff effective for five years.
Xcel Energy for Colorado	Rate Schedule SGL	Customer Charge: ✓ Energy Charge: ✓ Demand Charge: ✓ Time of Use Rate: ×	Low load factor (<30%) customers receive a distribution demand charge and seasonal energy charge. Demand charge is lower and energy charge is higher for these customers compared to the secondary general service customers.
BGE	Rider 5, available to non-residential customers on Schedules GL or P	Schedules GL or P Customer Charge: ✓ Energy Charge: ✓ Demand Charge: ✓ Time of Use Rate: ✓	Demand Charge Credit; The demand charge credit amount is calculated as 50% of the aggregated maximum demand of charging location for L2 EV chargers and/or DC Fast EV chargers. Rider available through December 31, 2023 or for 30 months from the date of approval.
National Grid	Available to non-residential customers on General C&I Rate G-02 or Large Demand Rate G-32 for dedicated DCFC purposes	G-02 and G-32 Customer Charge: ✓ Energy Charge: ✓ Demand Charge: ✓ Time of Use Rate: ✓ (for G-32)	Demand Charge Credit; The monthly bill discount is based on a per-kW credit set at the same rate as the distribution demand charge for a three-year period beginning with the start of service.

Q33. Did you design an EV TOU rate as an alternative to Eversource's Rate GV rate, which is the rate available to high-demand draw customers?

A33: Yes, I have. I designed an illustrative EV TOU rate for the Rate GV class, using data available from Eversource's workpapers submitted in Docket No. DE 20-170 as well as data responses to intervenor questions. While this rate is designed largely based on the most recent publicly-available Eversource data, it should be viewed as illustrative at this time. There are several reasons for this: 1) while we made an effort to use the most recent data in our rate design, it may very well be that Eversource may have more recent data for various parts of our rate design analysis; and 2) some of the data, such as "probability of peak" which underlie Eversource's allocation of marginal costs to pricing periods, was not provided in full. Therefore, we have not had a chance to fully review the reasonability of these allocations and have developed our own.

Q34. Please describe the High-Demand Draw EV TOU rate you have designed.

A34: I have designed a two-period, seasonal EV TOU rate, which is revenue neutral to the Rate GV rate. This rate eliminates the demand charge and allocates the revenues that would have been recovered by the demand charge to distribution component of the TOU rate. I maintained the customer charge at $211.21 per month, as in the Rate GV rate. I adopted the peak period definition used by the Company, which is 12 p.m. to 7 p.m. during weekdays and all other hours are offpeak. Summer is defined as May through September, while winter is defined as October through April based on my analysis of Eversource's system load profile. As presented in Table 4, this rate results in a peak to offpeak ratio of 4.2:1 in the summer and 2:1 in the winter.

TABLE 4: ENERGY'S ILLUSTRATIVE HIGH-DEMAND DRAW EV TOU RATE FOR EVERSOURCE
($ PER KWH)

	Generation ($/kWh)	Transmission ($/kWh)	Distribution ($/kWh)	Other charges ($/kWh)	**Total ($/kWh)**
Summer					
Peak	$0.158	$0.106	$0.031	$0.016	**$0.310**
Offpeak	$0.034	$0.000	$0.024	$0.016	**$0.074**
Winter					
Peak	$0.057	$0.093	$0.024	$0.016	**$0.190**
Offpeak	$0.056	$0.006	$0.022	$0.016	**$0.099**

	Peak	**:Offpeak**
Summer ratio	4.2	:1
Winter ratio	1.9	:1

Note: Other charges include SCRC, SBC, and other volumetric charges. Customer charge is kept at $211.21/month as in Rate GV.

Q35. Please explain how you designed the energy supply component of the EV TOU rate.

A35: I first obtained the annual energy supply revenue requirement for Rate GV by multiplying the Rate GV total annual load by the energy supply rate of $0.06025 /kWh, which was provided by Eversource in DE 20-170.[30] I allocated 20% of this revenue to FCM and the remaining 80% to non-FCM costs.[31] FCM costs were allocated only to summer peak hours as the capacity obligation is driven by the coincidence of Company system peak load with ISO-NE peak which has historically happened in the summer. The FCM-related rate was obtained by dividing the FCM costs by the load in the summer peak periods. I allocated the non-FCM revenue requirement to winter and summer seasons in proportion to the marginal costs of generation in winter and summer.

[30] Attachment SIS-6 (DE 21-078 Eversource Response to DOE 1-001 Attachment EAD-2 Workpaper).

[31] FCM constitutes approximately 20% of the annual value of wholesale electricity markets. Eric Johnson, Overview of Wholesale Electricity Markets: New England Energy Vision Wholesale Markets Design Technical Forum, ISO New England, January 13, 2021, page 16. https://www.iso-ne.com/static-assets/documents/2021/01/isone_overview_and_regional_update_wholesale_markets_2020_1_13_final.pdf

After obtaining the revenue requirements for winter and summer, I allocated it to TOU periods within each season. First, I calculated a marginal rate for each TOU period by dividing the total marginal costs across each TOU period by the total load in that same period. Next, I calculated an average marginal rate by dividing the total marginal costs in the season by the total seasonal load. I applied the ratios between these marginal rates by period and average marginal rate to the average rate implied by the revenue requirement to derive the energy supply component of the TOU rate.

Q36. Please explain how you designed the transmission component of the EV TOU rate.

A36: I first obtained the annual transmission revenue requirement for Rate GV from the materials provided by Eversource in DE 20-170.[32] I then allocated the annual revenue to winter and summer months based on the seasonal proportions of the transmission revenue in 2020 according to the TCAM proceeding in DE 21-109.[33]

After obtaining the seasonal transmission revenue requirement, I allocated it to TOU periods based on the probability of ISO-NE monthly peak hours occurring in each TOU period. These probabilities were calculated based on the frequency of ISO-NE monthly peak hour occurrence during each TOU period from 2010 to 2020.

Next I calculated the TOU rates by dividing the revenue allocated to each TOU period by the total load in that period.

Q37. Please explain how you designed the distribution component of the EV TOU rate.

A37: I first obtained the annual distribution revenue requirement for Rate GV from Eversource's workpapers submitted in DE 20-170.[34] To allocate the annual revenue

[32] Attachment SIS-6 (DE 21-078 Eversource Response to DOE 1-001 Attachment EAD-2 Workpaper).

[33] Docket No. DE 21-109 Joint Testimony of Erica L. Menard and James E. Mathews. Attachment ELM-1 Page 7-8. https://www.puc.nh.gov/regulatory/Docketbk/2021/21-109/INITIAL%20FILING%20-%20PETITION/2021-109_2021.07.20_EVERSOURCE-ATT-JT-TESTIMONY-MENARD-MATHEWS.PDF

[34] Attachment SIS-6 (DE 21-078 Eversource Response to DOE 1-001 Attachment EAD-2 Workpaper).

requirement to TOU periods within winter and summer months, I performed the following calculations. Starting with the hourly system load profile,[35] I took the square of the load in each hour and then summed up the squared loads for all 8760 hours. I calculated each hour's percentage allocation based on its squared load. I applied this allocation to the annual distribution revenue requirement and summed up the allocated costs by season and period. Next, I divided the revenue allocated to each TOU period by the total Rate GV load in that period to obtain the distribution component of the TOU rates.

This approach has allowed me to emphasize the contribution of high demand hours in driving the distribution system investment needs, and assign a higher percentage of the distribution revenue requirement to these high demand hours.

Q38. Do you consider this proposed EV TOU rate to be a more economically efficient and equitable rate compared to Eversource's demand charge alternative?

A38: Yes, I do. EV TOU rates more accurately reflect the marginal cost of providing service to the customers. Customers are expected to consume electricity up to the point their marginal benefit is equal to the marginal cost of electricity. When they respond to these price signals and moderate their usage, then future utility investments in additional peak capacity can also be moderated. To the extent that the customers do not respond to price signals and continue to demand electricity during most expensive times for the grid, then they end up paying for the demand they impose on the system. This implies that this rate is more equitable, collecting the higher charges from customers who impose a higher demand on the system. Moreover, EV TOU rates for high demand draw EV charging applications send more economically efficient price signals such that owners of these charging stations can similarly pass on these costs to their customers. They might also invest in distributed generation resources (solar plus battery storage) to be able to manage higher peak period prices.

[35] Hourly load profiles were obtained from Docket No. DE 21-078 Eversource Response to DOE 1-013 Q-DOE 1-013 DOE 1-013 Attachment 1.

V. Assessment of Liberty Residential EV TOU rates and High Demand Draw Alternative

Q39. Please describe your understanding of how Liberty developed their residential EV TOU rates.

A39: Liberty did not present new residential EV TOU rates in DE 20-170 because the Company's residential EV TOU rates were approved in DE 19-064 and have been in effect. However, I understand that this rate was approved as a pilot rate in the battery storage pilot (DE 17-189).

Liberty's residential EV TOU rate has two seasons, summer (May–October) and winter (November–April). The rate structure includes three TOU periods, namely offpeak (OPP), midpeak (MPP), and critical peak (CPP). Weekends and holidays have only midpeak and offpeak periods. Customer charge is set at $11.35 per month. The TOU periods are assigned time-varying energy supply, transmission, and distribution service components. The charges for these three service components are calculated as follows:

- **Energy supply**: This component is calculated based on real time LMP, ancillary costs, FCM costs, RPS costs, and other costs. Hourly LMP and ancillary charges are used to calculate load-weighted average hourly costs in TOU periods. FCM costs are allocated to TOU periods based on the portion of annual system peaks in each TOU period over the 10-year period of 2008–2017. RPS compliance costs are the average cost per kWh costs obtained from Liberty's energy service filing and are applied equally across the TOU. The three portions above ($/kWh basis) are multiplied by the SCG load to obtain a base revenue. The difference between this base revenue and the total revenue requirement for the SCG default service is assigned to all TOU periods in proportion to their base revenues.
- **Transmission**: Total transmission costs are apportioned to TOU periods according to the probability of monthly coincident peak hour in summer and winter. Probabilities are based on the percentage of time over the past 10 years that monthly coincident peak hour has occurred during any particular TOU period.

- **Distribution**: A method referred to as 'cost duration method' is used to assign a more significant share of costs for peaking assets to the hours that rank highest on the load duration curve. Each hour of the year gets assigned a portion of the distribution costs to reflect usage for peak, intermediate, and baseload capacity. To obtain the $/kWh costs for each TOU period, hourly distribution costs within each TOU period are totaled and divided by the billing determinant (*i.e.*, total MWh of load) associated with that TOU period costs. Costs are apportioned between the two seasons based on the portion of kWh in each seasonal period. Fixed (non-volumetric) customer charges are not modified.

Table 5 presents the resulting rate design.

TABLE 5: LIBERTY RESIDENTIAL EV TOU RATE ($/KWH)

	Generation ($/kWh)	Transmission ($/kWh)	Distribution ($/kWh)	Other charges ($/kWh)	**Total ($/kWh)**
Summer					
Peak	$0.091	$0.110	$0.097	$0.006	**$0.304**
Midpeak	$0.064	$0.017	$0.053	$0.006	**$0.140**
Offpeak	$0.042	$0.001	$0.036	$0.006	**$0.085**
Winter					
Peak	$0.099	$0.136	$0.090	$0.006	**$0.330**
Midpeak	$0.097	$0.003	$0.063	$0.006	**$0.169**
Offpeak	$0.088	$0.002	$0.042	$0.006	**$0.138**

	Peak	**:Offpeak**
Summer ratio	3.6	:1
Winter ratio	2.4	:1

Note: Other charges include SCRC and SBC. Customer charge is $11.35 per month.
Source: Docket No. DE 19-064 Liberty TOU Model

Q40. What is your assessment of Liberty's residential EV TOU rate design?

A40: I agree with the approach used in the derivation of the energy supply and transmission components of the rate. While I agree with the *premise* of the "cost duration method" used in the derivation of the distribution component of the rate, I find it to be overly engineered. Based on the Technical Statement Regarding TOU Model (DE 17-189), cost duration method was developed "to better link the recovery of distribution system costs to the time periods during which system assets are being utilized. In doing so, the resulting rates are intended to accomplish two goals: 1) send a time-differentiated price signal to customers to encourage peak demand reduction, 2) ensure rates for each TOU period reflect the costs of the underlying assets used to meet demand at those times (i.e. cost causation)."[36] This idea is also evident in the Technical Statement, "... it is readily apparent that there are a small number of "peak" hours during which system assets necessary to meet demand are used very infrequently. Thus, it would be appropriate to assign a significant share of costs for these peaking assets to the hours that rank highest on the load duration curve."[37] [38]

Therefore, the primary purpose of the delivery TOU rate should be to create price signals to reduce the demand on those very infrequently used system assets, and avoid building more assets during those hours. There are alternative approaches to creating these effective price signals without using the complex allocation approach implied by the cost duration method.

Q41. Did you develop an alternative approach for the allocation of distribution costs?

A41: Yes, I have. I propose to allocate these costs based on the system load duration curve, in proportion to the square of the load in each hour. While this proposed allocation method is not the only approach to assign the distribution costs to time periods, and there might be other defensible options, I believe that this approach strikes a good balance between emphasizing high demand hours for allocation and using a more transparent and simple method.

I have not applied this approach for Liberty's residential EV TOU rate, but as explained below, I have applied it to generate an alternative (to demand charges) rate for high-demand draw commercial charging applications.

[36] Technical Statement Regarding TOU Model, DE 17-189, Page 3.

[37] Technical Statement Regarding TOU Model, DE 17-189, Page 4.

[38] Cost duration method leads to the following allocation of distribution costs: 30% of the costs are allocated to peak hours, 39% allocated to midpeak hours and 31% to offpeak hours.

Q42. Did Liberty develop a marketing plan to effectively target and educate its customers with electric vehicles to encourage their uptake of EV TOU rates?

A42: No, I am not aware of any formal plans and marketing budget allocated to effectively marketing EV TOU rates to customers. Increased adoption of EV TOU rates will benefit customers in the form of bill savings if they can shift their charging to offpeak periods. It will also benefit Liberty and other customers as the demand during system peak hours are moderated (due to customers shifting their charging load to offpeak periods) and avoid costly expansions. I strongly encourage the Company to develop a targeted marketing plan with the objective of increasing the uptake of the TOU rates among the EV customer population.

Q43. Did Liberty propose a plan for exploring EVSE embedded metering capabilities that could mitigate the second meter costs necessary to implement separately metered EV TOU rates?

A43: No, not at this time. I understand that the Commission has expressed an interest for utilities to further explore EVSE embedded metering capabilities that could potentially increase the adoption of EV TOU rates by mitigating the additional meter costs.[39] I encourage the Company to design a pilot/demonstration program to evaluate the technical feasibility of this option.

Q44. Please describe your understanding of the rate Liberty is proposing for commercial electric vehicle charging station customers.

A44: Liberty has proposed two new rates for two high demand draw classes, EV-L (>200 kW) and EV-M (20-200 kW), based on the existing G-1 and G-2 classes. Currently, revenue requirements for G-1 and G-2 classes are recovered mainly from demand charges (~80%), rather than volumetric charges. The proposed rate design shifts the revenue recovery from demand charges to volumetric charges (85%). Note that this rate structure reduces but does not completely eliminate demand charges.

[39] Order 26, 394, page 13.

The proposed rate includes three components: volumetric, customer, and demand charges. To obtain the new rates, the existing total revenue from customer, volumetric and demand charges are summed up, separately for G-1 and G-2. For each class, the total revenue is divided into three rate components based on a specified percentage split, which is 5% customer charge, 85% volumetric charge, and 10% demand charge. The new customer, volumetric, and demand charges are obtained by dividing these values by the billing determinants (number of customers, kWh consumption, kW consumption, respectively) for the relevant rate class.

Q45. Did Liberty also propose an EV TOU alternative for high demand draw electric charging stations? If not, please explain why.

A45: No. In its response to DOE 2-5,[40] Liberty stated that it did not agree that offering EV TOU rates for separately-metered high demand draw commercial applications would be the appropriate rate design for such electric vehicle charging installations. The Company argued that the premise of the residential rate was completely different from separately metered commercial customer applications in that while residential customers are likely to charge "when they are home most likely on the weekends and evenings, commercial applications provide charging for any time during the day when drivers are out in the community and need to charge."

Q46. Do you agree with this reasoning? If not, why.

A46: No. I do not. As I have previously discussed in my testimony, the Company should not second-guess the abilities of its public station owners to pass on some of these efficient price signals to their own customers. When faced with a TOU rate that charges them higher rates during the peak period, the owners of the public chargers are likely to respond with altering their own pricing structures, and passing on these price signals to their own customers. These price signals may motivate customers to use these stations during offpeak times, and to the extent that they need to charge during peak times, then they would need to pay for their fair share of using the system when the demand on the

[40] Attachment SIS-7 (Liberty Response to DOE 2-5).

system is high. If they do not pay for these costs, then it would imply that other customers would need to pay for their convenience of charging. The Company's responsibility is to offer the EV TOU rate that is more aligned with cost-causality and marginal-cost-based ratemaking principles and observe how market participants innovate in response to these rates.

Q47. Did you design an EV TOU rate as an alternative to Liberty's G-1 and G-2 rates that are the rates currently available to high-demand draw customers?

A47: Yes, I have. I designed an illustrative EV TOU rate for the Rate G-1 and G-2 classes, using data available from Liberty's workpapers submitted in DE 20-170 as well as responses to data requests. While this rate is designed largely based on the most recent publicly-available Liberty data, this rate design should be viewed only as illustrative at this time. There are several reasons for this: 1) while we made an effort to use the most recent data in our rate design, it may very well be that Liberty may have more recent data for various parts of our rate design analysis; and 2) where we did not have some of the required data, we made reasonable assumptions about the allocation of revenues across seasons.

Regardless, our rate design approach remains valid and can constitute a starting point for the Company to update with more complete data.

Q48. Please describe the EV TOU rate you have designed.

A48: I have designed a three-period, seasonal EV TOU rate that is revenue neutral to the summation of Rates G-1 and G-2 class revenue requirements. This rate eliminates the demand charge and allocates the revenues that would have been collected by the demand charge to the distribution component of the TOU rate. I maintained the customer charge at $428.76 /month for G-1 and $71.47 $/month for G-2, using the charges presented in Attachment SIS-8 (Liberty Response to Staff 1-6 Attachment Staff 1-6) for EV-L and EV-M. I adopted the peak, midpeak, and offpeak definitions used by the Company. As presented in Table 6, this rate results in a peak to offpeak ratio of 5.1:1 in the summer and 3.8:1 in the winter after time-varying and other volumetric charges are considered.

TABLE 6: ENERGY'S ILLUSTRATIVE HIGH-DEMAND DRAW EV TOU RATE FOR LIBERTY ($/KWH)

	Generation ($/kWh)	Transmission ($/kWh)	Distribution ($/kWh)	charges ($/kWh)	**Total ($/kWh)**
Summer					
Peak	$0.247	$0.144	$0.037	$0.006	**$0.433**
Midpeak	$0.061	$0.018	$0.033	$0.006	**$0.118**
Offpeak	$0.048	$0.000	$0.028	$0.006	**$0.082**
Winter					
Peak	$0.074	$0.166	$0.035	$0.006	**$0.281**
Midpeak	$0.060	$0.004	$0.030	$0.006	**$0.099**
Offpeak	$0.058	$0.003	$0.028	$0.006	**$0.095**

	Peak	**:Offpeak**
Summer ratio	5.3	:1
Winter ratio	3.0	:1

Note: The customer charge is $428.76/month for G-1 and $71.47/month for G-2.

Q49. Please explain how you designed the energy supply component of the EV TOU rate.

A49: I first calculated the annual energy supply revenue requirements for Rates G-1 and G-2. This was obtained by multiplying the summation of the G-1 and G-2 annual load[41] by the average estimated medium and large C&I energy service price provided by the Company.[42] I allocated 20% of this revenue to FCM and the remaining 80% to non-FCM costs.[43] FCM costs were allocated only to the peak periods in the summer. The FCM-related rate was obtained by dividing the FCM costs by the load in the summer peak periods. I allocated the non-FCM revenue requirement to the winter and summer months defined by the Company in proportion to the marginal costs of generation in winter and summer.

[41] Attachment SIS-8 (Liberty Response to Staff 1-6 Attachment Staff 1-6)

[42] Energy service prices were obtained from Attachment SIS-9 (Liberty Response to Energy 4-4 Attachment 4-4.1) and Attachment SIS-10 (Liberty Response to Energy 4-4 Attachment 4-4.2).

[43] FCM constitutes approximately 20% of the annual value of wholesale electricity markets. Eric Johnson, Overview of Wholesale Electricity Markets: New England Energy Vision Wholesale Markets Design Technical Forum, ISO New England, January 13, 2021, page 16. https://www.iso-ne.com/static-assets/documents/2021/01/isone_overview_and_regional_update_wholesale_markets_2020_1_13_final.pdf

After obtaining the revenue requirements for winter and summer, I allocated it to TOU periods within each season. First, I calculated a marginal rate for each TOU period by dividing the total marginal costs across each TOU period by the total load in that same period. Next, I calculated an average marginal rate by dividing the total marginal costs in the season by the total seasonal load. I applied the ratios between these marginal rates by period and average marginal rate to the average rate implied by the revenue requirement to derive the energy supply component of the TOU rate.

Q50. Please explain how you designed the transmission component of the EV TOU rate.

A50: I obtained the annual transmission revenue requirements for the G-1 and G-2 classes from the allocated transmission expenses reported in the transmission charges work papers provided by the Company.[44] I allocated the summation of the G-1 and G-2 transmission revenue requirement to the winter and summer months based on the seasonal proportions of the transmission revenue.[45]

After obtaining the seasonal transmission revenue requirement, I allocated it to TOU periods based on the probability of ISO-NE monthly peak hours occurring in each TOU period. These probabilities were calculated based on the frequency of ISO-NE monthly peak hour occurrence during each TOU period from 2010 to 2020.

Next I calculated the TOU rates by dividing the revenue allocated to each TOU period by the total load in that period.

[44] Transmission expenses were obtained from Attachment SIS-11 Liberty Response to Energy Attachment Energy 4-4.4.

[45] Transmission expenses were allocated to seasons using monthly transmission revenue data in Attachment SIS-12 Liberty Response to Energy 4-5 Attachment 4-5.

Q51. Please explain how you designed the distribution component of the EV TOU rate.

A51: I obtained the annual distribution revenue requirements for G-1 and G-2 from Attachment SIS-8.[46] I summed up the revenue requirements for G-1 and G-2 and removed the portion that is recovered through customer charges.

To allocate the annual revenue requirement to TOU periods within winter vs summer months, I performed the following calculations. Starting with the hourly system load profile, I took the square of the load in each hour and then summed up the squared loads for all 8760 hours. The system load profile was obtained from Liberty's residential TOU model.[47] I calculated each hour's percentage allocation based on its squared load. I applied this allocation to the annual distribution revenue requirement and summed up the allocated costs by season and period. Next, I divided the revenue allocated to each TOU period by the summation of G-1 and G-2 load in that period to obtain the distribution component of the TOU rates.

Q52. In your opinion, is this proposed EV TOU rate a more economically efficient and equitable rate compared to Liberty's demand charge alternative?

A52: Yes, I do. EV TOU rates more accurately reflect the marginal cost of providing service to the customers. Customers are expected to consume electricity up to the point their marginal benefit is equal to the marginal cost of electricity. When they respond to these price signals and moderate their usage, then future utility investments in additional peak capacity can also be moderated. To the extent that the customers do not respond to price signals and continue to demand electricity during most expensive times for the grid, then they end up paying for the demand they impose on the system. This implies that this rate is also more equitable, collecting the higher charges from customers who impose a higher demand on the system. Moreover, EV TOU rates for high demand draw EV charging applications send more economically efficient price signals such that owners of these charging stations can similarly pass on these costs to their

[46] Attachment SIS-8 (Liberty Response to Staff 1-6 Attachment Staff 1-6)

[47] Hourly load profile for the system was obtained from Docket No. DE 19-064 Liberty TOU Model.

customers. They might also invest in distributed generation resources (solar plus battery storage) to be able to manage higher peak period prices.

VI. Assessment of Unitil Residential EV TOU Rates and High Draw EV TOU Rates

Q53. What is the scope of your review for Unitil rate design?

A53: I will review and critique Unitil's separately metered residential EV TOU rate design and high-draw alternative EV rate. [48]

Q54. Are Unitil EV TOU rate designs consistent with the rate design principles discussed at the beginning of Mr. Taylor's testimony?

A54: To some extent. Unitil has applied the cost-reflectivity principle in the design of the generation and transmission rates, while it has not done the same for the distribution component of the rate, which represent roughly 30% of the residential class revenue requirement.

Q55. Please describe your understanding of how Unitil developed their residential EV TOU rates.

A55: Unitil proposes a residential EV TOU rate (TOU-EV-D) with two seasons and three TOU periods. Peak period is 3 p.m.–8 p.m. on non-holiday weekdays, midpeak period is 6 a.m.–3 p.m. on non-holiday weekdays. All other times are designated as offpeak. The proposed rate includes a customer charge of $5.26 per month. The volumetric TOU rates for different service components are calculated as the following:

- **Generation**: Generation cost includes an RPS and a non-RPS component. Non-RPS costs are obtained by assigning the power supply costs that are incurred by the residential class to each TOU period based on the ratios of marginal costs across TOU

[48] Unitil filed other electric vehicle related proposals in Docket No. DE 20-170 and Docket No. DE 21-030, which Unitil asserts will be addressed in Docket No. DE 21-030 rather than this proceeding. See, Attachment SIS-13 (Unitil Response Staff 1-008(b)).

periods. After these ratios are obtained, non-RPS rate for each TOU period is calculated by multiplying each season's average power supply charges by the ratios obtained above. RPS charges are allocated equally to all TOU periods.

- **Transmission**: Total transmission costs for each season are allocated to TOU periods based on the probability of ISO-NE peak occurring in each period. The probabilities are calculated based on how many times the ISO-NE monthly peak hour occurred during each TOU period from 2000–2020.[49] For each TOU period, the allocated cost is divided by the kWh deliveries to obtain the rate. A reconciliation amount is added equally to all periods to obtain the final rate. This calculation is performed separately for winter and summer.
- **Distribution**: Offpeak rate is set at a fixed value of 0.02941 $/kWh. This value results from an Excel goal-seek function that aims to achieve a 3:1 ratio for peak rate/offpeak rate. This calculation is performed separately for winter and summer.

Q56. Did Unitil allocate distribution costs using a method based on cost-causation?

A56: No, it did not. Mr. Taylor argues that "the costs associated with the distribution system are fixed in nature. These costs do not vary by time of day and as such have no bearing on developing a TOU rate that is purely cost causative."[50] He indicates that he did not rely on a method that relies on cost-causation principles, because "…If the TOU rates encourage customers to use the system assets during a different time periods, there is no reduction in the system assets required to meet the peak demands of those customers; these assets will simply be utilized during a different hour."

Q57. Do you agree with Unitil's reasoning for this choice?

A57: No, I do not. While the costs of the distribution system are largely fixed in the short term, all costs are variable in the long term. Even though the distribution costs do not vary on an hourly basis as do the generation and transmission costs, the timing and

[49] Docket No. DE 21-030, Exhibit JDT-1, Page 17 indicates that the historical data from the "most recent ten years" were used for this analysis; however, the TOU model workbook (DE 20-170 Staff 1-6 Attachment 7.xlsx) uses the twenty year period of 2000–2020.

[50] Docket No. DE 21-030, Exhibit JDT-1, Pages 17-18.

intensity of the distribution system use have implications for the future investment decisions. More specifically, since substations see more demand during peak periods, this may drive the future need for more investment. Even the local facilities may need upgrades if customers demand grows rapidly beyond the original design parameters. On the other hand, the same assets see a much lower demand during offpeak periods. This implies that the time-differentiated pricing of the distribution costs is justified to ensure more efficient use and expansion of the distribution system.

While Mr. Taylor acknowledges that the shifting of peak demand to offpeak periods reduces some distribution costs over time, he understates the importance of addressing this in the rate design by indicating that "load shifting may have some impact on the level of investment but it would be marginal given these costs would only represent a small portion of total system costs and would not impact the utilities cost structure in the next four years and would be extremely difficult to estimate."[51] Given the increasing trends towards electrification nationally and the very premise that this Commission has instructed utilities to design EV TOU rates to create efficient price signals for EV charging, I find Mr. Taylor's reasoning unsupported.

Q58. Did Unitil provide any supporting analysis demonstrating how the residential EV TOU rate season and time period definitions were determined?

A58: No, it did not. Summer is defined as May–October and winter is defined as November–April. Mr. Taylor presents four options for the time period definitions, however does not provide evidence to show that at least one of these options has a strong correlation with system load and marginal cost characteristics. These load shape and marginal cost clustering analyses are an important part of the rate design analysis and should have the same rigor as the analyses that involve allocation of costs to time periods.

[51] Docket No. DE 21-030, Exhibit JDT-1, Pages 19-20.

Q59. What is the proposed customer charge for the residential EV TOU rate?

A59: Unitil's residential EV TOU rate has a proposed customer charge of $5.26 per month. This charge is incremental to the customer charge they will be paying for their whole house service. My understanding is that this incremental rate reflects only the carrying cost associated with the separate meter, but does not include the incremental local facilities costs that may be created by the increased demand due to the charging of the EVs.

Q60. What is your assessment of Unitil's proposed residential EV TOU rate?

A60: Unitil's rate design is generally consistent with the guidance issued by the Commission on the ideal attributes of the EV TOU rates. It is seasonal, has three periods, and has a peak period of five hours with a peak to offpeak ratio of 3:1. However, there are still areas for improvement in the design of this rate:

- The Company should derive the distribution cost component of this rate in a way that assigns the costs of the system assets to those hours driving the need for those assets.
- The Company should evaluate whether it will incur additional costs resulting from customers' charging their EVs at home, in addition to the incremental costs associated with the meters.
- The Company should undertake an analysis of the system load profiles and marginal energy price profiles to prove that its season and time period definitions indeed reflect the system demand conditions. These definitions should be updated periodically as the system conditions evolve.

Q61. Has Unitil proposed to develop a marketing plan to effectively target and educate its customers with electric vehicles to encourage their uptake of EV TOU rates?

A61: Yes. Unitil has proposed to develop "a comprehensive, multi-channel marketing, communications and education plan that is designed to meaningfully increase consumer awareness, interest in and adoption of EVs, EV charging infrastructure and

EV TOU rates during the initial five years of the EV Program."[52] While the primary focus of this proposed plan is to increase adoption of electric vehicles through customer education and communication, it also covers efforts related to "new EV/TOU rates to encourage customer savings and electric system demand benefit from off-peak charging."[53] I applaud the Company for proposing this comprehensive marketing approach as often times the new rates and new programs as beneficial as they could be, may go unnoticed in the absence of targeted marketing and education campaigns.

Q62. Did Unitil propose a plan for exploring electric vehicle supply equipment (EVSE) embedded metering capabilities that could mitigate the second meter costs necessary to implement separately metered EV TOU rates?

A62: Yes. The Company has proposed a residential behind-the-meter EVSE installation and incentive program.[54] This program will allow the Company to test managed charging capabilities along with an opportunity to assess EVSE embedded metering capabilities.

Q63. Please describe your understanding of how Unitil developed their high-demand draw EV TOU rates.

A63: Unitil has proposed a high-demand draw EV TOU rate with two seasons and three TOU periods. Peak period is 3 p.m.–8 p.m. on non-holiday weekdays, midpeak period is 6 a.m.–3 p.m. on non-holiday weekdays. All other times are designated as offpeak.

High draw EV TOU rates are proposed for two classes: TOU-EV-G2 small general service for less than 200 kVA usage[55] and TOU-EV-G1 for large general service larger than 200 kVA.

52 Direct Testimony of Carroll, Simpson, Valianti, Exhibit CSV-1, page 44-45.

53 Direct Testimony of Carroll, Simpson, Valianti, Exhibit CSV-1, page 44.

54 Direct Testimony of Carroll, Simpson, Valianti, Exhibit CSV-1, pages 28-29.

55 Unitil has two types of G-2 customers. Unitil offers the TOU-EV-G2 rate only to G2 customers with demand charges.

The proposed rate includes a customer charge of $32.20 for G2, $178.93 for G1 secondary, and $95.42 for G1 primary service. The proposed rate has time-varying volumetric charges for generation and transmission and a demand charge for distribution:

- **Generation**: For G1, energy supply is not included in the rate structure as generation is provided through competitive suppliers. For G2, default service costs are used in a similar manner to allocate the power supply costs associated with the class to TOU periods as described for the Residential rates above.
- **Transmission**: The same procedure described for the Residential rate applies here.
- **Distribution**: The proposed demand charges are 11.59 $/kW for G2 (compared to the existing G2 demand charge of 10.51 $/kW), and 8.37 $/kVA for G1 (compared to the existing G1 demand charge of 7.60 $/kVA). However, Unitil proposes a demand charge holiday that will provide a 75% discount for the demand charges during customer's first year of enrollment in the rate, a 50% discount during the second year, and a 25% discount during the third year.

Q64. What is the basis for Unitil's decision to offer demand charge holidays for new EV charging facilities?

A64: Mr. Taylor has reviewed a few other utilities' offerings to address the challenges associated with demand charges and low utilization charging infrastructure in his testimony. His review however has mostly emphasized utilities that offer demand charge holidays. Unitil's premise is that demand charge holidays will help charging infrastructure owners "weather early costs from demand charges and low utilization."[56] However, Unitil does not discuss the implications of these unrecovered demand charges for other customers and how other customers will have to pay for these charges.

[56] Docket No. DE 21-030, Exhibit JDT-1 Page 30 of 38.

Mr. Taylor acknowledges the availability of a number of technologies to charging station owners that limit peak demand: "These technologies utilize set thresholds, algorithms, and machine learning to control the peak demand of the charging stations by controlling individual charging ports."[57] He does not discuss, however, why charging station owners would invest in these technologies in the absence of cost-based price signals.

Q65. What is your overall assessment of Unitil's demand charge alternative proposal for high-demand draw charging applications?

A65: While Unitil's proposed EV TOU rate for high-demand draw charging applications has successfully incorporated time-varying rates for generation and transmission elements of the rate, these efficient price signals would be muted by the demand charge holiday applied to the distribution component of the rate. This effectively boils down to cancelling the load shifting incentives provided by the generation and transmission TOU prices. Moreover, by extending the demand charge holiday to high-demand draw charging applications, Unitil's rate proposal would subsidize owners of the charging applications at the expense of other customers. I recommend that Unitil design an EV TOU rate as an alternative to demand charges, using the approach utilized in the design of Energy's illustrative EV TOU rate for Unitil.

Q66. Did you design an EV TOU rate as an alternative to Unitil's EV TOU rates developed for G1 and G2that are the rates available to high-demand draw customers?

A66: Yes, I have. I designed an illustrative EV TOU distribution rate for the G1 class as an alternative to demand charges, using data available from Unitil's workpapers in DE 20-170 and DE 21-030 as well as publicly-available data. [58] While this rate is designed largely based on the most recent publicly-available Unitil data, it should be viewed as illustrative at this time. While we made an effort to use the most recent data in our rate design, it may very well be that Unitil may have more recent data for various parts of

[57] Docket No. DE 21-030, Exhibit JDT-1 Page 33 of 38.

[58] Unitil's distribution revenue requirement was excerpted from its proposed revenue requirement in the ongoing rate case, but will need to be updated to reflect the ultimate resolution of Unitil's rate request.

our rate design analysis. Since Unitil has already developed TOU rates for the transmission component, I adopted Unitil's approach for transmission rates; however, I allocated the transmission revenue requirements to TOU periods based on the ISO-NE monthly peaks in the 2010–2020 period rather than the twenty-year period (2000–2020) used by Unitil. For the generation component, Unitil did not develop a time-varying rate since G1 customers are receiving energy supply from retailers. For this reason, I also did not develop a time-varying generation rate.

Q67. Please describe the illustrative EV TOU distribution rate you have designed.

A67: I have designed a three-period, seasonal EV TOU distribution rate by adopting the season and TOU period definitions provided by the Company. This rate is revenue neutral to the portion of the G1 distribution revenue requirement after customer charges are subtracted. This rate eliminates the demand charge and recovers the revenue requirement through time-varying volumetric rates. I used an illustrative customer charge at $137.18 per month for G1, which is the average of the customer charges for the primary and secondary voltage G1 customers. I adopted the peak, midpeak, and offpeak definitions used by the Company. As presented in Table 7, this distribution rate results in a peak to offpeak ratio of 6.5:1 in the summer and 6.4:1 in the winter after time-varying and other volumetric charges are considered.

TABLE 7: ENERGY'S ILLUSTRATIVE HIGH-DEMAND DRAW EV TOU RATE FOR UNITIL ($/KWH)

	Generation ($/kWh)	Transmission ($/kWh)	Distribution ($/kWh)	Other charges ($/kWh)	**Total ($/kWh)**
Summer					
Peak	N/A	$0.178	$0.032	$0.008	**$0.217**
Midpeak	N/A	$0.021	$0.024	$0.008	**$0.052**
Offpeak	N/A	$0.004	$0.022	$0.008	**$0.033**
Winter					
Peak	N/A	$0.188	$0.027	$0.008	**$0.222**
Midpeak	N/A	$0.007	$0.022	$0.008	**$0.037**
Offpeak	N/A	$0.006	$0.021	$0.008	**$0.035**

	Peak	**:Offpeak**
Summer ratio	6.5	:1
Winter ratio	6.4	:1

Note: The Peak/Offpeak ratio excludes generation, since G1 customers receive energy supply from third party providers. The illustrative customer charge is 137.18 $/month, which is the average of the customer charges for the primary and secondary voltage G1 customers.

Q68. Please explain how you designed the distribution component of the EV TOU rate.

A68: I first obtained the annual distribution revenue requirements for G1 and removed the portion that is recovered through customer charges. [59]

To allocate the annual revenue requirement to TOU periods within winter vs summer months, I performed the following calculations. Starting with Unitil's hourly system load profile, I took the square of the load in each hour and then summed up the squared loads for all 8760 hours. I obtained Unitil's hourly system load profile by summing the

[59] I obtained the G1 distribution revenue requirement by subtracting the revenue recovered through customer charges from the total distribution revenue requirement for G1 reported in DE 21-030. Testimony of Ronald J. Amen. Attachment RJA-5, Page 3-3. Bates Page 1367. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2021/21-030/INITIAL%20FILING%20-%20PETITION/21-030_2021-04-02_UES_ATT_TESTIMONY_AMEN.PDF

class load profiles for Unitil's four rate classes[60] multiplied by the customer counts in each class.[61] I calculated each hour's percentage allocation based on its squared load. I applied this allocation to the annual distribution revenue requirement and summed up the allocated costs by season and period. Next, I divided the revenue allocated to each TOU period by the total G1 load in that period to obtain the distribution component of the TOU rates.

Q69. Why is your illustrative EV TOU rate more preferable compared to Unitil's proposed rate with demand charges?

A69: The illustrative EV TOU rate allocates distribution costs to different hours based on the demand imposed on the system during those hours. Cost-reflective price signals created by this approach are expected to incentivize customers to shift their load to lower cost hours and mitigate the peak growth. This rate is also more equitable and does not lead to cross subsidies as would be the case under Unitil's proposed demand charge holiday.

VII. Findings and Recommendations

Q70. Please summarize your findings and recommendations related to the design of the EV TOU rates.

A70: My key findings and recommendations are as follows:

- I recommend that all three utilities propose an EV TOU alternative to current demand charge based rates for high demand draw commercial customer applications. In the absence of demand charges, the TOU rate is more consistent with the marginal cost principles, while minimizing cross subsidies.

[60] Unitil's class average load profiles were obtained from the Company website. https://unitil.com/sites/default/files/excel/UESPROFILES20.xlsx

[61] Customer counts were obtained from DE 21-030. Testimony of Ronald J. Amen. Attachment RJA-5, Page 2-3. Bates Page 1366. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2021/21-030/INITIAL%20FILING%20-%20PETITION/21-030_2021-04-02_UES_ATT_TESTIMONY_AMEN.PDF

- Utilities' arguments for commercial EV charging applications not being ideal for TOU rates are not warranted. Unless utilities design rates reflecting efficient marginal cost-based price signals, market participants will not respond with innovation.
- The State of NH does not have an official transportation electrification public-policy goal, therefore there is no public-policy basis for extending cross-subsidies for commercial charging applications at this time.
- Given that Eversource is not able to implement a three period EV TOU rate for its residential customers at this time, the two-period domestic TOU rate will be the transitional rate for these customers. A seasonally differentiated two-period rate with a shorter peak window that reflects the marginal facility costs and a lower customer charge will provide stronger price signals and is more likely to be attractive to customers both with and without EVs.
- Eversource's proposed high draw demand alternative rate to demand charges is revenue neutral at the 10% station utilization level for which it was designed. While this rate is designed to recover at least a portion of demand related revenues in the form of volumetric charges, it will still lead to cross-subsidies. Moreover, this rate does not provide marginal cost based price signals for a more efficient use of the system assets. I recommend that the Company designs an EV TOU rate as an alternative to demand charges, using the approach utilized in the design of Energy's illustrative EV TOU rate for Eversource.
- Liberty has not proposed a new residential EV TOU at this time as it offers a three-period seasonal rate initially offered for battery storage customers. This rate will also be available to separately metered EV TOU customers. I recommend that Liberty revisits this rate design periodically to ensure that the time periods are still reflective of system demand conditions and lead to efficient charging behavior.
- Liberty's proposed high-draw demand alternative to demand charges is a revenue neutral volumetric rate that reduces most of the charges collected from demand charges, but not all. This rate, however, does not provide price signals that will incentivize a more efficient use of the system assets. I recommend that the Company

designs an EV TOU rate as an alternative to demand charges, using the approach utilized in the design of Energy's illustrative EV TOU rate for Liberty.

- While Unitil's rate design is generally consistent with the guidance issued by the Commission on the ideal attributes of the EV TOU rates, the distribution component of the rate is "imposed" to achieve a 3:1 peak to offpeak ratio. The Company should derive the distribution cost component of this rate in a way that assigns the costs of the system assets to those hours driving the need for those assets. The Company should undertake an analysis of the system load profiles and marginal energy price profiles to prove that its season and time period definitions indeed reflect the system demand conditions. The Company should also evaluate whether it will incur additional costs resulting from customers' charging their EVs at home, in addition to the incremental costs associated with the meters.
- Unitil has proposed an EV TOU rate for high-demand draw applications that introduces time varying rates for the generation and transmission components of this rate. However, Unitil's proposed rate still maintains the original demand charge component and instead proposes a three-year demand charge holiday. These cross subsidies for the commercial charging facilities are not warranted given that increased transportation electrification is not an official public-policy goal in New Hampshire. I recommend that the Company designs an EV TOU rate as an alternative to demand charges, using the approach utilized in the design of Energy's illustrative EV TOU rate for Unitil.

Q71. Please provide your recommendations related to the implementation of EV TOU rates

A71: I have several recommendations related to the implementation of EV TOU rates. First, the Commission should direct each utility to offer a customer-contributed meter option. The additional meter required to offer separately metered EV TOU rates has the potential to increase a customer's monthly charge, particularly for residential customers, in a manner which would unnecessarily dissuade them from embracing the time of use rate. Providing a customer contributed meter option would ensure costs associated with the additional meter are not shifted to other customers and would allow

EV TOU customers to more quickly recoup the cost associated with the meter via potential bill savings. Second, the Commission should direct both Liberty and Eversource to develop a plan to market their time of use rate proposals; neither Liberty nor Eversource quantified costs associated with such a plan, in spite of having previously been directed to do so by the Commission. Third, the Commission should direct both Eversource and Liberty to develop a pilot similar to Unitil's proposal to test the feasibility of using EVSE's embedded metering technologies. Fourth, the Commission should require annual reports from the utilities regarding customer enrollment, customer charging profiles, and the status of the above-described alternative metering assessment pilots.

Q72. Does this conclude your testimony?

A72: Yes.

Attachment SIS-1

Sanem Sergici

PRINCIPAL

Boston, MA | +1.617.864.7900 | Sanem.Sergici@brattle.com

Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in innovative retail rate design and economic analysis of distributed energy resources (DERs). She regularly assists her clients in matters related to electrification, grid modernization investments, emerging utility business models and alternative ratemaking mechanisms.

Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs across North America. She led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and smart rate offerings for electricity customers. She also has significant expertise in resource planning, development of load forecasting models and energy litigation.

Dr. Sergici regularly publishes in academic and industry journals and presents at industry events. She was recently featured in Public Utility Fortnightly Magazine's "Fortnightly Under 40 2019" list. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her MA in Economics from Northeastern University, and BS in Economics from Middle East Technical University (METU), Ankara, Turkey.

AREAS OF EXPERTISE

- Innivative Retail Electricity Pricing
- Grid Modernization
- Electrification
- Distributed Energy Resources
- Resource Planning

EXPERT TESTIMONY AND REGULATORY FILINGS

Testimony before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Application by Nova Scotia Power Incorporated for Approval of Time-Varying Pricing Tariff Application - M09777, May 17, 2021.

Filed rebuttal evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, April 22, 2021.

Filed direct evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, November 30, 2020.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-057, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 20, 2019.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-064, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 6, 2019.

SELECTED CONSULTING EXPERIENCE

UTILITY REGULATORY AND BUSINESS MODELS

- Assisted the New York Department of Public Service to develop a comprehensive financial model of a representative (downstate) New York utility capable of demonstrating the impacts of REV initiatives upon utility financial performance. Our modeling effort included developing plausible incentive regulation frameworks, new incentive mechanisms, and potential platform frameworks, services and futures.
- Development of Performance Incentive Metrics for the Joint Utilities of New York. The Brattle Group worked with the New York PSC Staff and, subsequently, with the State’s six investor owned electric utilities (Joint Utilities) in analyzing the feasibility and impacts associated with proposed earnings sharing mechanisms (EAMs), primarily the EAMs associated with load factor and system efficiency.

- Assisted a North American Utility with development of a short-term and long-term regulatory strategy to enable their 2030 Vision. Brattle team interviewed the executive team; identified consensus views and disagreements on alternative business models and regulatory models. Developed straw proposals for two potential regulatory models one focused on enabling shorter-term outcomes, and the other focused on enabling Company's longer-term vision.
- Assisted Pepco D.C. as they develop a multi-year rate plan and various traditional and emerging performance incentive metrics to be filed in their upcoming rate case. Brattle team developed and facilitated workshops to introduce Pepco's MYRP proposal to the stakeholders and assisted Pepco with incorporating stakeholder input to the final proposal.
- Assisted a Canadian Utility with a critical assessment of their custom incentive ratemaking model and discussed how it compares with other forms of PBR. We presented a jurisdictional scan of the PBR implementations across North America and Europe, and assessed pros and cons of each approach. We also advised them on currently proposed "Distributed Utility Models" and assess pros and cons of each model; reviewed "Alternative Regulatory Models" that were developed to ensure that utilities can coexist with the DERs and continue to maintain healthy balance sheets.
- For a Canadian electric utility, reviewed and summarized alternative regulatory frameworks and incentive models that would support a sustainable energy efficiency business. Investigated the pros and cons of these models, identified the implications of each model for the utility, and made a recommendation based on our findings. Utility will discuss the recommended approach with the regulator and seek an approval.
- For a large Canadian electric utility, assisted with the development of an alternative proposal to their current performance based regulation (PBR) framework. Examined and benchmarked several examples of performance based regulation schemes in place for other utilities, and advised on an enhanced PBR mechanism.

INNOVATIVE RATE DESIGN AND IMPACT EVALUATION STUDIES

- Assisted with rate design proposal. Brattle has been retained by Nova Scotia power to assist with a comprehensive evaluation of innovative rate designs and development of Company's rate design proposal including load and bill impact analyses. Brattle team participated in stakeholder sessions to socialize the rate design with the stakeholders.
- Review of Rate Design Studies on Behalf of the Staff of the New Hampshire Public Utilities Commission. Brattle reviewed the rate design studies presented by Liberty Utilities and Eversource and filed testimony on behalf of the Staff. Both studies focused on the distribution services offered by the utilities and examined and testified on issues involving embedded and marginal cost based rate design. Dr. Sergici filed direct testimony in the proceeding.

- Design, measurement and verification of Maryland Joint Utilities' PC44 TOU pilot. Brattle serves as the technical lead on behalf of the Maryland Joint Utilities, and led the pilot design and M&V methodology work streams in the PC44 workgroup process. Brattle will evaluate results from these three pilots in 2020.
- Assisted a New Zealand distribution utility with development of a peak time rebate pilot. Advised the client in pilot design principles and calculated sample sizes to yield statistically significant results. Undertook empirical testing of more than 150 different baseline methods using the client data and recommended an approach that leads to the highest accuracy and lowest bias in predicting the event day usage.
- Developed a model for the Ontario Energy Board to estimate a counterfactual hourly customer demand profile for multiple innovative pricing profiles of interest. Evaluated the economic efficiency of each alternative pricing option, taking into account system cost drivers including energy, ancillary services, generation capacity, and transmission and distribution capacity, as well as overall changes to consumer welfare driven by induced changes in demand. This represents one of few efforts to fully quantify the societal costs and benefits of innovative rate structures and involved close collaboration with the OEB team to ensure the Ontario-specific market structures were accurately reflected in our analysis.
- Technical Advisor to OEB on the New RPP Pilots. A Brattle team led by Dr. Sergici has developed a Technical Manual to guide the design and impact evaluation of new RPP pilots. Dr. Sergici has been closely working with the OEB RPP team as they oversee the implementation of these pilots in accordance with the guidelines
- Undertook impact Evaluation of Ontario's Time-of-Use Rates on Behalf of Ontario Power Authority. A Brattle team led by Dr. Sergici provided an impact evaluation of Ontario's province-wide roll-out of Time-of-Use (TOU) rates for its residential and general service customers on behalf of Ontario Power Authority. Brattle acquired hourly load data from the IESO and the LDCs, aggregated it for the pricing periods that correspond to the TOU rate, reinterpreted the full-scale deployment as a natural experiment, and analyzed it using econometric methods for three consecutive years.
- Undertook a retail rate benchmarking study for a large southwestern utility. Our team, led by Dr. Sergici, reviewed utility resource plans to estimate each utility's retail rate trajectory. We compared the utilities across a variety of rate drivers, such as reserve margin, fuel mix, load growth, load factor, renewables investment requirements, and demand-side activities, and provided strategic recommendations for addressing these drivers of future rate growth.
- Undertook an extensive review of the rate designs and methodologies used by other jurisdictions/countries for a large Canadian Utility. We reviewed the rates that are currently offered by a large Canadian utility and compared them with best industry practices from around

the globe. As a result of our analysis, we identify some near term and long term alternative rate design options for our client, which can help them to manage revenue risks and volatility due to the effects of disruptive threats, and at the same time to increase innovation and affordability in the rate options presented to the customers.

- Assisted Pepco Holdings, Inc. to evaluate the effectiveness of the AMI-enabled energy managements tools (EMTs) in reducing per capita energy use. Led a team of four researchers to compile and process data for four of the PHI jurisdictions; identify relevant control groups and methodology for impact evaluation and undertake an econometric analysis to quantify the EMT impact.
- Assisted an industry-leading provider of integrated demand response, energy efficiency, and customer engagement solutions in the design of and M&V plan for a behavioral demand response program. The plan included a detailed section on sampling selection for statistically valid and detectable program impact results.
- Prepared a comprehensive blueprint document for measuring the impacts of Baltimore Gas and Electric Company's Smart Grid Customer Programs. BGE has started deploying smart meters to all of its residential customers in Spring of 2012 and is scheduled to complete the deployment over a three-year period. BGE developed a full-scale program, "Smart Energy Manager (SEM)" program, to meet a central objective of the Smart Grid Initiative - customer education and engagement in a Smart Grid environment. The blueprint documented the design elements of the SEM program and introducing the approaches that will be used to measure the impacts of different SEM tools once the program is in the field and sufficient data are collected.
- Measurement and evaluation for in-home displays, home energy controllers, smart appliances and alternative rates for FPL. Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.
- Pricing and technology pilot design and interim impact evaluation for Commonwealth Edison Company (ComEd). Assisted ComEd in the design of an ambitious pilot program that included approximately 25 different treatment cells. The pilot, which is the first "opt-out" pilot program of its kind, involved 8,000 customers and tested the impact of dynamic prices with and without customer education, informational feedback through basic and advanced feedback devices, and other enabling technologies in the summer of 2010. Conducted an interim impact evaluation study preceding the formal impact evaluation of the study, which is planned to be completed by the end of 2011.

- Pricing and technology pilot design and impact evaluation for Consumers Energy. Designed Consumers Energy's pricing and technology pilot and conducted the impact evaluation study after the pilot was completed in September 2010. The pilot tested critical peak pricing (CPP) and peak time rebates (PTR) in conjunction with information treatment and technology. The pilot also tested the potential "Hawthorne bias" for a group of control group customers who were aware of their involvement in the pilot.
- Member of a Technical Advisory Group (TAG), which was formed by Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL). Reviewed and provided feedback on the experimental designs of the utilities that were awarded Smart Grid Investment Grant projects and participated in periodic project review meetings with utilities to review and provide feedback on the interim results as they implement their projects. As part of this assignment, authored a guidance document that discussed different impact evaluation methods, which can be selected by the utilities. This document was shared with the utilities and other TAG members.
- For an Independent System Operator (ISO), designed, managed and analyzed a market research to help improve participation in retail electricity products that encourage price-responsive demand (PRD). The research determined customer preferences for various time-based pricing products that would help define PRD products that may be developed in the ISO for each customer class. ISO will use the results of this research to assist in modifying wholesale market design to better support such PRD products.
- Assisted a client in conceptually developing a new product that would increase customer participation and performance in energy efficiency (EE) and demand response (DR) programs. Developed Total Resource Cost (TRC) tests for a few targeted EE and DR programs, and modeled the benefits and costs with and without the client's new product offering
- Co-authored a whitepaper reviewing the results from five recent pilot and full-scale programs that investigated low-income customer price-responsiveness to dynamic prices. The core finding of the whitepaper is that low income customers are responsive to dynamic rates and that many such customers can benefit even without shifting load.
- For a large California utility, conducted an econometric analysis, which investigated the role of weather conditions, smart meter installations, and electricity rate increases, among other control variables, in explaining the changes in the monthly usages and bills of a group of complaining customers. Estimated pooled regressions using a panel dataset, as well as individual customer regressions for more than 1,000 customers.
- Assisted an Illinois electric utility in the assessment of alternative baseline calculation for implementing peak time rebate (PTR) programs. Under a PTR program, participants receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event

hours. This requires establishment of a baseline load from which the reductions can be computed. The analysis involved simulating baselines for more than 2,000 customers using five alternative methodologies for several event days. Identified and recommended the baseline calculation methodology that yielded the most accurate baseline for individual customers, through the use of MAPE and RMSE statistics.

- Evaluated the Plan-It Wise Energy program (PWEP) of Connecticut Light and Power (CL&P) Company. PWEP tested the impacts of critical peak pricing (CPP), peak time rebates (PTR), and time of use (TOU) rates on the consumption behaviors of residential and small commercial customers. Each rate design was tested with high and low price variation as well as with and without enabling technologies. Conducted an econometric analysis to determine weather dependent substitution and daily price elasticities and subsequently quantified demand and energy impacts for each of the treatments tested in the PWEP. Developed optimal rate designs to be adopted in a full deployment scenario.
- For Baltimore Gas and Electric Company, assisted in the preparation of direct and rebuttal expert testimonies before the Maryland Public Service Commission, that explain the design and results of 2008 and 2009 Smart Energy Pricing (SEP) pilots.
- Evaluated the Smart Energy Pricing (SEP) pilot program of Baltimore Gas and Electric Company for three consecutive years. The pilot was designed to quantify the impacts of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. Conducted an econometric analysis to estimate demand systems and predict substitution and daily price elasticities for participating customers. Using the parameters of the demand equations, quantified demand, energy, and bill impacts associated with the programs. Impacts of the socio-demographic characteristics of the participants as well as their ownership of enabling technologies were separately identified on the demand response of the program participants.
- Co-authored a business practice manual for forecasting price responsive demand (PRD) in Midwest ISO. The draft manual introduces different methodologies for measuring and incorporating PRD into forecast LSE requirement for LSEs that are at different stages of rolling-out their out their dynamic pricing programs. The draft manual also proposes methodologies for the verification of the forecasted demand net of PRD for long term planning purposes.
- Assisted in the development of an affidavit that evaluates the implications of PJM's proposed revisions to the Operating Agreement (OA) on barriers to participation in PJM's Economic and Emergency Load Response programs.
- Co-authored a whitepaper on "Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets" for Institute for Electric Efficiency. Whitepaper is intended to help facilitate nationwide progress toward the deployment of dynamic pricing of electricity by summarizing

information that may assist utilities and regulators who are assessing the business case for advanced metering infrastructure (AMI).

- Assisted a New York utility in benchmarking their existing Demand Response (DR) portfolio to the best practice in U.S. and recommended improvements in their planned DR portfolio. Also assisted the utility in quantifying costs and benefits of pilot programs proposed in their DR filing before the State of New York Public Service Commission.
- Assisted an electric utility in developing a residential pricing pilot program that tests inclining-block rate (IBR) structure. More specifically, designed several revenue neutral IBR alternatives and quantified load reduction and bill impacts from these IBR rates.
- Assisted an electric utility in their dynamic rate design efforts. Conducted impact analyses of converting from a flat rate design to alternative dynamic rate designs for each of the five major customer rate classes of the utility. Developed models that allow simulation of energy, demand, and bill impacts by season, day type and time period for an average customer from each of customer classes.
- Simulated the potential demand response of an Illinois utility's residential customers enrolled in real time prices. Results of this simulation were used in recent Midwest ISO Supply Adequacy Working Group (SAWG) meeting to facilitate conversation about price responsive demand in the region. Simulations were run for different scenarios including historic versus spiky real-time prices; peak versus uniform allocation of capacity charges; and with and without enabling technologies.
- Designed a survey on Long-run Drivers of U.S. Energy Efficiency and Demand Response Potential on behalf of EPRI and EEI. Conducted statistical analyses to examine the survey responses, which were turned in by more than 300 power industry leaders and academic experts. Using the outcomes from this survey, assisted in the development of future scenarios to model energy efficiency and demand response impact through 2030.
- Assisted in the preparation of an EEI report that quantifies the benefits to consumers and utilities of dynamic pricing. Undertook a comprehensive review of the dynamic pricing programs across the U.S. and elsewhere. Also implemented price response simulations to quantify the likely peak demand reductions that would realize under alternative dynamic pricing schemes.

DISTRIBUTED ENERGY RESOURCES AND GRID MODERNIZATION

- Development of an Econometric Based EV Forecast for Baltimore Gas and Electric Company. The Brattle Team has compiled a comprehensive repository of national EV adoption related data and estimated an econometric model to explain the drivers of US EV sales, using data from 50 states, from 2011-2019. BGE had expressed a strong preference for a model that relates drivers of EV adoption to sales and did not want to use top down forecasts or a diffusion models due to their inflexibility to update assumptions. With the econometric model, it was possible to develop various forecasts depending on federal, state and utility incentives; different battery cost trajectories; alternative EV TOU rates; utility owned charging infrastructure among many other drivers. This econometric model was also supplemented by another system-dynamics based module that captured the supply side drivers of EV sales such as increasing model availability, charging infrastructure and improved R&D activities. Brattle team developed alternative EV sales scenarios for BGE's service territory and analyzed the impacts of EV load (under managed and unmanaged scenarios) on utility ratemaking, infrastructure investments and other financial metrics.

- For a U.S. utility, reviewed the utility's benefit cost assessment model used to evaluate distributed energy resources for alignment with commission orders and staff guidance. The assessment identified areas for refinement, including increasing the temporal and geographic granularity of the model. As part of the review, the Brattle team provided insights into potential misalignments between the valuation of transmission and distribution investment deferral within the model, customer value, and system value. The Brattle team rebuilt the model from the ground-up to allow for intuitive use and ensure that assumptions are clearly articulated and well-documented.
- For PGE, led the Brattle team developing EV potential as part of PGE's 2021 DER potential study. Developed light, medium and heavy duty vehicle forecasts through 2040, and quantified the peak, energy and EV charging infrastructure implications of these EV forecasts.
- For an east coast IOU, conducted analysis to forecast how the utility's load would increase if aggressive decarbonization goals are met through electrification, and to determine the extent to which energy efficiency and load flexibility measures could mitigate that load growth, highlighting the key role that load flexibility will play in facilitating the decarbonization transition.
- For a DER software developer, estimated the potential market value of residential load flexibility offerings across five utilities. The analysis highlighted that the load flexibility value proposition varies significantly depending on system and market conditions. The final report is a key input to the company's load flexibility business case.
- For a large east-coast utility, reviewed benefit cost framework and model data to evaluate non-pipe options. The review included treatment of geographic differences in marginal costs due to pipeline access, and the Brattle team rebuilt the model from the ground-up to allow for intuitive use.

- System Dynamics Modeling of DER Adoption and Utility Business Impacts. Led the development of Brattle's Corporate Risk Integrated Strategy Platform (CRISP) model and assisted utility clients with the implementation of this model. CRISP is based on System Dynamics approach, which creates simulations based on dynamic feedbacks between utility policies and customer behavior, providing a new perspective on how much and how fast the "utility of the future" must evolve. The focus of these modeling efforts was to help utilities anticipate and accommodate distributed energy resources (DERs) as they become more economical and more widely adapted by retail electricity customers, and to evaluate the sustainability of their traditional cost-of-service business model in the face of such trends.
- Co-led a study for EPRI that analyzed a variety of approaches to representing DERs in utility planning models. Started with energy efficiency as the first DER to be analyzed, and undertook a comprehensive literature review to capture the complete range of options for evaluating EE in IRPs. Next, quantitatively evaluated the impact of the EE modeling method on important IRP objectives such as minimizing total resource costs, meeting environmental goals, and avoiding suboptimal resource planning decisions.
- Estimated NEM cross-subsidies using data from sixteen utilities. Used cost-of-service methodology to compare NEM customers costs on the system vs. revenue collection from these customers using company COS studies, and supplementing it by publicly available data on solar PV production profiles, installed DG capacity by utility and system load profiles.
- Wrote a comprehensive report for National Electrical Manufacturer's Association (NEMA) that reviews most recently approved 10 major grid modernization projects. Report discusses business cases and cost recovery mechanisms for each of these projects and documents how grid modernization technologies have benefitted customers and utilities.
- Analyzed the impacts of electric utility infrastructure investment on system reliability and resiliency for a Northeastern Utility, following major weather events. Primary area of analysis involved estimation of economic value of investments to customers using value of lost load (VOLL) metrics for electric system investments.
- Assisted Pepco Holdings, Inc. to analyze the Phase I of its Conservation Voltage Reduction (CVR) program in its Maryland Service Territory. First of its kind, this econometric study compares consumption of the treatment and control groups before and after the implementation of CVR. More specifically, a regression analysis was conducted to compare the usage levels of treatment and control group customers to determine whether the CVR treatment resulted in statistically significant conservation and peak demand impacts. The analysis accounts for exogenous factors such as weather, calendar and seasonality impacts as well as utility energy and demand savings programs.

DECARBONIZATION POLICY AND RESOURCE PLANNING

- Evaluated how policy reforms could increase access and decrease costs of C&I renewable procurement for the REBA Institute, a group representing commercial and industrial (C&I) customers in the United States, through utility subscription programs, power purchase agreements, and third-party retailer providers. The report finds that there is much potential to increase C&I procurement and costs, but the policy pathway to enable these results is dependent on state characteristics. The report finds that introducing supply choice has the greatest potential to increase access but presents uncertainty regarding costs, and that utility subscription programs can present significant near-term opportunities.
- Currently assisting New York City's Mayor's Office of Sustainability to evaluate how a carbon trading scheme would impact the costs and benefits of implementing Local Law 97, an ambitious building-sector decarbonization law that mandates 80% emission reductions by 2050. In collaboration with larger consulting team, Brattle team is evaluating building segment data regarding the size and energy use of buildings covered by LL97, reviewing and modeling efficiency and electrification emission abatement retrofits, modeling building owner decision making to comply with the law, and is designing carbon trading policy to ensure the program meets the needs of the city government, environmental justice community, and ultimately lowers societal costs.
- Led the Brattle team that assisted the New York City Mayor's Office of Sustainability with the development of New York City's Roadmap to 80 x 50. The Brattle team analyzed the change in energy-sector greenhouse gas (GHG) emissions resulting from more than six future scenarios. These scenarios explored the impacts of aggressive energy efficiency efforts, off-shore wind, and the continuance of low natural gas prices on the emissions footprint of New York City. The analysis shows that in order to reach 80 x 50, New York City will need to achieve a significant portion of its GHG reductions as a result of a dramatic shift towards a renewables-based grid. This shift towards renewables must overcome the anticipated retirement of nuclear facilities prior to 2050 and will be supported by the implementation of New York State's Clean Energy Standard and the declining cost of renewable energy.
- Conducted a study involving "solar to solar" comparison of equal amounts of residential- and utility-scale PV solar deployed in Xcel Energy Colorado's Service Area. Calculated costs and benefits of each of these two different but equally sized solar options, i.e., avoided energy, capacity and distribution network costs and others. The study found carbon reductions were greater on utility scale systems because the solar energy per MW is much higher on utility-scale due to better placement and tracking capability.
- Advised Nova Scotia Power Inc. on the reasonableness of the DSM scenarios and strategies that are being modeled in their Integrated Resource Plan (IRP). This effort also involved advising the

Company on a variety of DSM issues and building up a model that quantifies the rate impacts for program participants and non-participants based on the selected DSM scenario.

- Coauthored the State's Annual Integrated Resource Plan (IRP) for the Connecticut Department of Energy and Environmental Protection (DEEP). This effort involved development of scenarios and strategies for an electric system to meet long-range electric demand while considering the growth of renewable energy, energy efficiency, other demand-side resources. Led the development of demand side management and emerging technology resource strategies and analyses involving these resources.
- Developed a model to assess the prudence of an electric utility's power procurement strategy in comparison to several other alternative options. As a result of this model, she assessed whether it is prudent to recover the congestion and loss costs associated with utility's chosen strategy from ratepayers in a state regulatory proceeding.
- Assisted in preparation of a marginal cost study for an integrated electric utility. The study estimated the incremental costs to the utility of serving additional demand and customer by time period, sub-region, and customer class. The costs were identified as energy, capacity and customer related for generation, transmission, and distribution systems of the utility.
- Assisted in developing an integrated resource plan for major electric utilities. Contributed to the design of future scenarios against which the resource solutions were evaluated. Designed scenarios were driven by external factors including fuel prices, load growth, generation technology capital costs, and changes in environmental regulations. Forecasted the inputs series for the resource planning model consistent with each of the designed scenarios.

DEMAND FORECASTING

- For an Asian utility considering an investment on a generation plant in PJM, we have reviewed, replicated, and developed alternative load forecasts using PJM's 2017 update. We have determined several uncertainty factors that are not fully captured in PJM's forecasting framework and developed "low load" and "high load" scenarios after accounting for these factors.
- For an electric utility in the Southeast, reviewed load forecasting models for residential and commercial customer classes. Assessed the accuracy and validity of the models by reviewing the historic and forecast period inputs to the model; model specification; in-sample and out-of-sample accuracy statistics; and incorporation of DSM impacts to the model, among many others. Also conducted an analysis using the U.S. Energy Information Administration's Annual Energy Outlook (AEO) data to determine the forecast errors during pre and post-recession periods.

- Developed a blueprint for integrating energy efficiency program impacts into the load forecasts for a Canadian Utility. This effort involved estimating the future impact of energy efficiency programs to be included in the load forecasts and developing price elasticity estimates that can be used to forecast the impact of the future changes in the price of electricity.
- Developed a load forecasting model for the pumping load of California State Water Project. Identified the main drivers of pumping load in major pumping stations. Through Monte Carlo simulations, quantified the uncertainty around load forecasts.
- Assisted in the preparation of testimony that evaluates the reasonableness of Florida Power and Light Co.'s total customer and monthly net energy for load (NEL) forecasting models. In addition to evaluating the methodology, also reviewed the reasonableness of the inputs used in the historic and forecast periods and assessed the soundness of ex-post adjustments made to the forecasts.
- Assisted PJM in the evaluation of its models for forecasting peak demand and re-estimated new models to validate recommendations. Predicted forecasting errors of the existing models and helped improving the forecast methodology by introducing the state-of-the art estimation techniques. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.
- Assisted a large utility in New York in understanding the decline in electric sales during the recent past and attributed the decline to a change in customer expectations of future income, based on declining consumer confidence that has been created by the lingering economic recession.
- Reviewed the structure of the Tennessee Valley Authority's energy sales forecasting models by sector, assessed the magnitudes of the price elasticities and the model specifications used to generate them, analyzed the ability of the models to generate a baseline forecast that could serve as a point of reference when evaluating the likely impacts and cost-effectiveness of a wide range of new energy efficiency and demand response programs.
- Developed a demand forecast model for one of the world's largest steam system operators. Estimated regression models to predict the price elasticities and switching behavior of different consumer classes. Also helped in the development of a model to forecast the impact of alternative steam tariffs on the consumption and switching patterns of consumers.

ENERGY LITIGATION AND MARKET POWER ANALYSIS

- For the California Parties, provided Brattle witness with litigation support and testimony regarding manipulation of electric power and natural gas prices in the western U.S. during 2000-01. The proceeding, before the Federal Energy Regulatory Commission involved Enron, Dynegy, Mirant, Reliant, Williams, Powerex and many other suppliers in the U.S. and Canada.

- Part of a Brattle team that analyzed the impacts of a merger, involving FirstEnergy and West Penn Power, on competition in retail electricity markets on behalf of Brattle testifying expert Mr. Frank Graves. Both companies owned electric distribution companies, transmission assets, generation resources, and retail electricity providers in several Mid-Atlantic States. The analysis involved assessment of whether the increased market share in wholesale energy markets affects retail competition, the number of suppliers in retail electricity markets, the ease of entry and exit to provide electricity to retail customers directly or through default service procurements, and the potential for abusing affiliate relationships with the electric distribution company to favor the retail electricity provider affiliate.
- Assisted in preparing affidavit before the Federal Energy Regulatory Commission examining whether the proposed acquisition of a power plant by an electric utility would lead to anti-competitive effects on wholesale market competition. In addition to performing market power tests required by FERC, directed an analysis that investigates the historical electric trading patterns between the acquiring utility and the other parties in the relevant geographical market. FERC agreed with the conclusion of the affidavit and authorized the transaction.
- Assisted in the development of testimony before the Postal Rate Commission involving calculation of mail processing variabilities and data quality issues. Addressed the endogeneity problems in the estimation of the variabilities using the instrumental variables approach.

TECHNICAL AND EXPERT REPORTS

- *PC44 Time of Use Pilots: Year One Evaluation*, with Ahmad Faruqui, Nicholas E. Powers, Sai Shetty, and Jingchen Jiang, prepared for Maryland Joint Utilities (September 15, 2020)
- *Nova Scotia Utility and Review Board: Time-Varying Pricing Project Submission*, with Ahmad Faruqui, prepared for the Nova Scotia Power (June 30, 2020)
- *Getting to 20 Million EVs by 2030: Opportunities for the Electricity Industry in Preparing for an EV Future*, with Michael Hagerty and Long Lam, published by The Brattle Group, Inc. (June 2020)
- *Renewable Energy Policy Pathways*, with Judy Chang, Kasparas Spokas, Maria Castaner, and Peter Jones, prepared in collaboration with the REBA Institute (May 2020)

- *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, with Samuel A. Newell, Michael Hagerty, Evan Cohen, Sang H. Gang, John Wroble, and Patrick S. Daou, prepared for PJM (March 17, 2020)
- *Energy Efficiency Administrator Models: Relative Strengths and Impact on Energy Efficiency Program Success,* with Nicole Irwin, prepared for Uplight (November 2019)
- *Incorporating Distributed Energy Resources into Resource Planning: Energy Efficiency*, with Ryan Hledik, D.L. Oates, Tony Lee, and Jill Moraski, prepared for EPRI (May 2019)
- *Status of DSM Cost Recovery and Incentive Mechanisms,* with Ahmad Faruqui, Elaine Cunha, and John Higham, prepared for Baltimore Gas & Electric (February 20, 2019)
- *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates: Response to PC51 Request for Comments*, W. Zarakas, S. Sergici, P. Donohoo-Vallett, and N. Irwin, prepared for Joint Utilities of Maryland and filed in support of comments in PC51 for the Maryland Public Utilities Commission (March 29, 2019)
- *U.S. Alternative Regulatory Mechanisms: Scope, Status and Future,* with William Zarakas and Pearl Donohoo-Vallett, prepared for Baltimore Gas & Electric, Delmarva Power & Light and Pepco (February 19, 2019)
- *A Review of Pay for Performance (P4P) Programs and M&V 2.0*, with Heidi Bishop and Ahmad Faruqui, prepared for Commonwealth Edison (July 20, 2018)
- *Reviewing the Business Case and Cost Recovery for Grid Modernization Investments,* with Michelle Li and Rebecca Carroll, prepared for National Electrical Manufacturers Association (NEM) (2018)
- *Pepco Maryland In-Home Display Pilot Analysis*, with Ahmad Faruqui, prepared for Pepco (June 2017)
- *80x50 Energy Sector Model Assumptions and Results,* with Michael Kline and Pearl Donohoo-Vallett, prepared for the Mayor's Office of Sustainability (January 4, 2017)
- *Impact Evaluation of Pepco District of Columbia's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco District of Columbia (October 2016)
- *Impact Evaluation of Delmarva Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Delmarva Maryland (April 2016)
- *Impact Evaluation of Pepco Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland (January 2016)

- *Impact Evaluation of Pepco Maryland's Phase I Conservation Voltage Reduction (CVR) Program,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland (July 2015)
- *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study,* with Neil Lessem, Ahmad Faruqui, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Independent Electric System Operator (February 2016) http://www.ieso.ca/Documents/reports/Final-Analysis-of- Ontarios-Full-Scale-Roll-Out-of-TOU-Rates.pdf
- *Comparative Generation Costs of Utility-Scale and Residential Scale PV in Xcel Energy Colorado's Service Area,* with Bruce Tsuchida, Bob Mudge, Will Gorman, Peter Fox-Penner and Jens Schoene (EnernNex), prepared for First Solar (July 2015)
- *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast,* with Ahmad Faruqui and Kathleen Spees, prepared for The Sustainable FERC Project (September 2014)
- *Assessment of Load Factor as a System Efficiency Earning Adjustment Mechanism*, with William Zarakas, Kevin Arritt, and David Kwok, prepared for The Joint Utilities of New York (February 2017)
- *Expert Declaration in a Patent Dispute Case involving a Demand Response Product* (July 2014)
- *Measurement and Verification Principles for Behavior-Based Efficiency Programs,* with Ahmad Faruqui, prepared for Opower (May 2011) http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf
- *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets,* with Ahmad Faruqui and Lisa Wood, IEE Whitepaper (June 2009)
- *The Impact of Dynamic Pricing on Low Income Customers,* with Ahmad Faruqui and Jennifer Palmer, IEE Whitepaper (June 2010)

ARTICLES & PUBLICATIONS

- "Bridging the Chasm between Pilots and Full-Scale Deployment of Time-of-Use Rates," *The Electricity Journal*, Volume 33, Issue 10 (December 2020)
- "Top Performing States in Energy Efficiency: Top States' Secret Sauce," *Public Utilities Fortnightly* (March 2020)

- "Quantifying Net Energy Metering Subsidies," with Yingxia Yang, Maria Castaner, and Ahmad Faruqui, *The Electricity Journal*, Volume 32, Issue 8 (October 2019)
- "Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity," with Ahmad Faruqui and Cody Warner, *The Electricity Journal*, Volume 30, Issue 10 (December 2017)
- "Do Manufacturing Firms Relocate in Response to Rising Electric Rates?" with Ahmad Faruqui, *Energy Regulation Quarterly*, Volume 5, Issue 2 (June 2017)
- "Dynamic Pricing Works in a Hot, Humid Climate," with Ahmad Faruqui and Neil Lessem, *Public Utilities Fortnightly* (May 2017)
- "The impact of AMI-enabled conservation voltage reduction on energy consumption and peak demand," with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:2, pp. 60-65 (March 2017) http://www.sciencedirect.com/science/article/pii/S1040619016302536
- "Integration of residential PV and its implications for current and future residential electricity demand in the United States," with Derya Eryilmaz, *The Electricity Journal*, 29, 41-52 (2016)
- "Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," with Neil Lessem and Dean Mountain, *Energy Economics*, 52, pp. 39-48 (December 2015)
- "Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment," with William Zarakas, *et al*., *The Electricity Journal*, Volume 27, Issue 5 (June 2014)
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- "Arcturus: International Evidence on Dynamic Pricing," with Ahmad Faruqui, *The Electricity Journal*, 26:7, pp. 55-65 (August/September 2013)
- "Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan," by Ahmad Faruqui, Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, pp. 571–584 (August 2013)
- "Dynamic Pricing of Electricity in the Mid-Atlantic Region: Econometric Results from the Baltimore Gas and Electric Company Experiment," with Ahmad Faruqui, *Journal of Regulatory Economics*, 40(1), pp. 82–109 (2011)

- "The Untold Story of: A Survey of C&I Dynamic Pricing Pilot Studies," with Ahmad Faruqui and Jenny Palmer, *Metering International*, Issue 3 (2010)
- Divestiture policy and operating efficiency in U.S. electric power distribution," with John E. Kwoka, Jr., and Michael Pollitt, *Journal of Regulatory Economics* (June 2010)
- "Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence," with Ahmad Faruqui, *Journal of Regulatory Economics* (October 2010)
- "Rethinking Prices," with Ahmad Faruqui and Ryan Hledik, *Public Utilities Fortnightly* (January 2010)
- "Piloting the Smart Grid," with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal* (August/September 2009)
- "The Impact of Informational Feedback on Energy Consumption - A Survey of the Experimental Evidence," with Ahmad Faruqui and Ahmed Sharif, *Energy-The International Journal* (August 2009)
- "Three Essays on U.S. Electricity Restructuring," Unpublished Ph.D. Thesis, Northeastern University (August 2008)

PRESENTATIONS & SPEAKING ENGAGMENTS

- "A New Approach to Strategic Planning in a High Distributed Resource Environment: Distributed Solar as a Case Study," Next-Gen Smart Grid Virtual Summit (December 9, 2020)
- "What Explains the Success of Top Performing States in Energy Efficiency?" NRRI Webinar (August 19, 2020)
- "A Blueprint to Pilot Design: Best Practices and Lessons Learned," MI Power Grid: Energy Programs and Technology Pilots Stakeholder Meeting (April 30, 2020)
- "Policies in Support of Customers' Purchase of Renewable Energy," NARUC Annual Meeting & Education Conference (November 18, 2019)
- "Rate Reform in Evolving Energy Marketplace," EUCI Residential Demand Charges/TOU Summit (May 30, 2019)
- "Grid Modernization: Policy, Market Trends and Directions Forward," 4th Annual Grid Modernization Forum, Chicago, IL (May 21, 2019)
- "Accelerating the Renewable Energy Transformation: Role of Green Power Tariffs and Blockchain," EUCI Southeast Clean Power Summit (February 25, 2019)

- "The Case for Alternative Regulation and Unintended Consequences of Net Energy Metering," 46th Annual PURC Conference, Gainesville, FL (February 21, 2019)
- "Reviewing Grid Modernization Investments: Summary of Recent Methods and Projects," National Electrical Manufacturers Association (NEMA) (December 4, 2018)
- "Enabling Grid Modernization Through Alternative Rates and Alternative Regulation," Energy Policy Roundtable in the PJM Footprint (November 29, 2018)
- "Return of Pay-for-Performance Stronger with M&V 2.0," BECC Conference, Innovations in Models, Metrics, and Customer Choice, Washington DC (October 2018)
- "Rate Design in a High DER Environment," MEDSIS Rate Design Workshop, Washington DC, (September 2018)
- "Demand Response for Natural Gas Distribution," Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, Monterey CA (June 2018)
- "Status of Restructuring: Wholesale and Retail Markets," National Conference of State Legislatures Workshop, "Electricity Markets and State Challenges," Indianapolis IN (June 2018)
- "Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida," International Energy Policy & Programme Evaluation Conference, Bangkok Thailand (November 2017)
- "Understanding Residential Customer Response to Demand Charges: Present and Future," EUCI Residential Demand Charges Conference, Chicago IL (October 2016)
- "Utility Leaders Workshop: An Evolving Utility Business Model for the Caribbean," Caribbean Renewable Energy Forum, Miami FL (October 2016)
- "Impact of Residential PV Penetration on Load Growth Expectations," AEIC Western Load Research Conference, September 2016.
- "Moving away from Flat Rates," Smart Grid Consumer Collaborative, Chicago, IL (September 2016)
- "Residential Demand Charges: An Overview," EUCI Demand Charge Conference, Phoenix AZ (June 2016)
- "Conservation Voltage Reduction Econometric Impact Analysis," AESP Spring Conference, Washington DC (May 2016)

- "Caribbean Utility 2.0 Workshop- Economics, Tariffs and Implementation: The Challenge of Integrating Renewable Resources and After Engineering Solutions," co-hosted and presented at the Caribbean Renewable Energy Forum, Miami FL (October 2015)
- "Dispelling Common Residential DR Myths," eSource Conference (October 2015)
- "Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities," NYU School Law's Forum on New York REV and the Role of Time Varying Pricing (March 2015)
- "Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments," EDF Demand Response Workshop, Paris, France (July 2014) and Governors Association's Michigan Retreat on Peak Shaving to Reduce Wasted Energy (August 2014)
- "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," 2014 Smart Grid Virtual Summit, Boston (June 2014)
- "Residential Demand Response Opportunities," Opower Webinar Series, Boston (June 2014)
- "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," 33rd Annual Eastern CRRI Conference (May 2014)
- "The Arc of Price Responsiveness—Consistency of Results Across Time-Varying Pricing Studies," Chartwell Webinar, Boston (May 2013)
- "Evaluation of Baltimore Gas and Electric Company's Smart Energy Pricing Program," 9th International Industrial Organization Conference, Boston, MA (April 2011)
- "Dynamic Pricing: What Have We Learned?" Electricity Markets Initiative Conference, Harrisburg, PA (April 2011)
- "Do Smart Rates Short Change Customers," Demand Resource Coordinating Committee Webinar (December 2010)
- "Opening Remarks and Session Chair of Day 1," FRA Conference on Customer Engagement in a Smart Grid World, San Francisco, CA (December 2010)
- "The Impact of Informational Feedback on Energy Consumption," 2010 National Town Meeting on Demand Response and Smart Grid (June 2010)
- "The Impact of In-Home Displays on Energy Consumption," Colorado Public Service Commission (June 2010)

- “Does Dynamic Pricing Work in the Mid-Atlantic Region: Econometric Analysis of Experimental Data,” Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- “Distributed Generation in a Smart Grid Environment,” panel speaker at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- “Power of Information Feedback: A Survey of Experimental Evidence,” Peak Load Management Alliance (PLMA) Webinar (April 2010)
- “Customer Response to Dynamic Pricing - A Long Term Vision,” 2009 NASUCA Mid- Year Meeting, Boston (June 2009)
- “BGE’s Smart Energy Pricing Pilot Summer 2008 Impact Evaluation,” Association of Edison Illuminating Companies (AECI) Conference, Florida (May 2009)
- "California and Maryland - Are They Poles Apart?," Western Load Research Association Conference, Atlanta (March 2009)
- “Experimental Design Considerations in Evaluating the Smart Grid," Smart Grid Information Session Massachusetts DPU (December 2008)
- “Divestiture, Vertical Integration, and Efficiency: An Exploratory Analysis of Electric Power Distribution,” 4th International Industrial Organization Conference, Boston, Massachusetts (2006)

Attachment SIS-2

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-170

Date Request Received: 07/21/2021 **Date of Response: 08/04/2021**
Request No. DOE 2-019 **Page 1 of 1**
Request from: Department of Energy

Witness: Dennis E. Moore

Request:
Reference Company Response Staff 1-010, stating "The initial activity to identify these costs and a timeline was to capture high level scope and business requirements for a proposed dynamic EV TOU rate which included up to 3 daily periods differentiated for weekdays, weekends and holidays. Through a series of requirement gathering sessions, high-level requirements for metering, billing and reporting system modifications were identified. These high-level requirements were subsequently used to estimate incremental IT costs for solution development & testing as well as project support costs. The lead time of 30 months includes activities for project mobilization, requirements refinement (6 months), plus a development and delivery timeline of roughly up to 24 months based off of past projects with equivalent scope and complexity." Please provide any documents prepared in order to identify costs and a timeline, including meeting minutes, agendas, memos, presentations, or other materials.

Response:
Please refer to Attachment 1 for a summary of the Company's cost estimate and Attachment 2 for the final project scope and business requirements for implementation of the propose rate.

Project Details	Estimate	Timeline
Incremental Development and Testing IT Costs	$7,200,000	18 – 24 Months
Incremental Project Support Costs	$1,920,000	
Total	$9,120,000	

Key Assumptions:

1. This is a high-level order of magnitude estimate and timeline using only incremental Vendor, Supplier, and Contractor costs.
2. Assumes that 3-part usage data will be sent to competitive suppliers for purposes of pass-through billing and that changes will be made to C2 billing system for Eversource to bill 3-part prices on behalf of competitive suppliers for complete billing.
3. Metering, billing, and reporting changes are required to build a new Electric Vehicle rate.
4. Estimate does not include meter purchase, installation, nor overhead related to meter management.
5. Estimate includes resource cost associated with gathering requirements, responding to design questions, testing, training, implementation, and post implementation support.
6. Assumes interval read meters are used.
7. Bill changes will be required.

Project Name: NH Electric Vehicle 3 Part TOU Rate
Date: Updated 03/11/2021 v13

IT Business Solutions Analyst: Business Solution Analysts

Business & IT contributors to this document (title):

1. Director
2. Manager
3. Domain Architect
4. Supervisor
5. Analyst
6. Analyst
7. Analyst
8. Analyst
9. Strategist
10. Project Manager
11. Consultant
12. Developer
13. Developer
14. Developer
15. Manager

Background

As part of the 2020 NH Rate Case Settlement agreement, Eversource has been asked to propose a 3-part electric vehicle charging station Time of Use rate.

Under the proposal, all 3 parts of TOU rate must have different rates for distribution, supply, and transmission. This document outlines the high-level scope for the metering, billing and reporting changes to be made to support the proposal. Using the attached Liberty Utilities proposed rate as a guide, the following are the requirements.

High-Level Business Requirements:

In Scope:

All 3 parts of TOU rate must have different rates for distribution, supply, and transmission.

Metering Requirements

1. Business to set up interval meter configuration for 3-part TOU in NH MV90xi to generate BDET (Billing Determinate) file automatically.

Summary of changes to utilize Meter Bill Tracker in the process for 3-part TOU Rate (NEW)

2. Create separate instance of the Meter Bill Tracker (MTB) for NH.
   - This includes creating separate instance of Meter Bill File Watcher to import data from C2.
   - Alternatively, modify the existing instance to accommodate NH data.
     - This may be a better long term solution, but take longer to implement.
3. PowerTrack Export of meters, modified to get NH interval meters for use by the mainframe C2 COBOL program for extracting customer data.
4. C2 COBOL program (KILMRXIN) that extracts customer / meter from C2 to send to the MBT system each morning as the C2 download file.

- A separate download file should be created for NH
  - or
- The Meter Bill File Watcher service that imports the file to the MBT will need modified to filter on company code for both the CTMA data and the NH data.

5. MBT FileWatcher service to import the customer data for NH from the C2 download file.
6. MBT UI changes to present the mid-peak values to the user.
7. File Scanner BDF Generator process to calculate the index values for mid-peak, based off of the consumption data and prior index values contained within MBT. (Refer to diagram)
8. Changes to MBT to accommodate NH Billing cycles in MBT
9. Changes to MBT to be able to filter & search NH data.
10. Changes to MBT to export the mid-peak index values with the on & off peak values.
11. May need a separate export/extract file from MBT to C2 for NH reads. Ideally, you would send NH reads and CTMA (Connecticut / Massachusetts) reads together.
12. If NH resources need to be restricted from accessing CTMA data MBT, this would require a change to roles for MBT users to isolate access to NH vs. CTMA data.
13. MBT changes to accommodate and/or separate NH data errors.

Billing Requirements

1. Create new billing meter type configurations for 3-part TOU.
2. Create new usage detail types for 3-part TOU.
3. Create new C2 service plan options (residential, commercial) for 3-Part TOU. EV rates will bill On-peak, Mid-Peak, and Critical and Total. Rates for energy (kWh) based changes are based on two seasonal periods.
4. Change C2 bill file to send data (including new On-peak, Mid-Peak, and Critical and Total rates) to KUBRA for purposes of bill print. Pending design discussion, this may be a change to the Meter Box on left-hand side of bill and the Billing Determinates on right-hand side of bill calculation. KUBRA will need to make changes to accept the new data in the modified C2 file and render the bill.
5. Modify EDI file sent to competitive suppliers to include the 3-part usage (On-peak, Mid-Peak, and Critical and Total). This would be needed for customers who elect pass-through billing but most likely will be required for complete billing customers as well.

Reporting Requirements

1. If needed, modify files sent to Load Research to include hourly or native intervals off the interval meter.
2. Change existing Revenue Reports for Accounting to track the new EV rate in C2.

Out of Scope:

1. Changes to Eversource.com

Assumptions:

1. The MBT solution would be in-place at least until C2 is replaced with SAP.
2. No changes required for NH LPB. Assumption is that EV customers can be billed in C2.

3. Requirements will be based on the proposed Liberty Utilities Tariff on last page.
4. Eversource will own the meter which will be a basic kWh Survey Type One-Channel Interval Meter. That meter is a recording meter that can record in 5 to 30-minute intervals.
5. File scanner changes will be required for moving meter data.
6. Estimates will include incremental IT effort only.
7. Estimate does not include the purchase or installation of the meter nor any of the business overhead related to managing the meters for NH.
8. Load Settlement regression testing required.

Rate EV Plug In Electric Vehicle

Availability
Retail Delivery Service under this rate is available for uses of a customer taking service under Rate D as a separately metered service. By choosing to participate in this Plug In Electric Vehicle rate, the Customer agrees to pay the following charges for a minimum of two years. The charging station shall be connected by means of an approved circuit to a separate electric vehicle charging meter. The rates for energy (kWh) based charges are seasonal with a winter period from November 1 to April 30 and a summer period from May 1 to October 31.

Character of Service
Service supplied under this rate will be single phase, 60 cycle, alternating current, normally three-wire service at a nominal voltage of 120/240 volts or three-wire 120/208 volts, whichever is available at the location.

Rates per Month

The rate per month will be the sum of the applicable Customer and Energy Charges subject to the adjustments in this tariff:

Rates for Retail Delivery Service Effective November 1, 2020 through April 30, 2021

Customer Charge	$11.35 per month
Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)	
Distribution Charge Off Peak	4.196
Distribution Charge Mid Peak	6.289
Distribution Charge Critical Peak	8.955
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge Off Peak	4.204
Total Distribution Charge Mid Peak	6.297
Total Distribution Charge Critical Peak	8.963
Transmission Charge Off Peak	0.212
Transmission Charge Mid Peak	0.337
Transmission Charge Critical Peak	13.615
Energy Service Charge Off Peak	7.411
Energy Service Charge Mid Peak	8.871
Energy Service Charge Critical Peak	9.208
Stranded Cost Adjustment Factor	(0.072)
Storm Recovery Adjustment Factor	0.000

Off peak hours will be from 12AM to 8AM and 8PM to 12AM daily.
Mid peak hours will be from 8AM to 3PM daily Monday through Friday, except holidays.
Mid peak hours will be from 8AM to 8PM Saturday, Sunday and holidays.
Critical peak hours will be from 3PM to 8PM daily Monday through Friday, except holidays.

Attachment SIS-3

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-170

Date Request Received: 08/13/2021 **Date of Response: 08/27/2021**
Request No. DOE 3-008 **Page 1 of 1**
Request from: Department of Energy

Witness: Dennis E. Moore

Request:
Reference Eversource Response 2-19, attachment 1.

a. Please provide the more detailed breakdown of the costs discussed at the August 9, 2021 technical session.
b. Please also indicate which of these costs would change if Eversource were to revise its EV TOU proposal to reflect a two period, three part TOU rate (G/T/D).
c. Please also indicate which of these costs would change if Eversource were to revise its EV TOU proposal to reflect a two period, two part TOU rate (T/D).

Response:
a. Refer to Attachment 1 for more detailed breakdown of the costs discussed at the August 9, 2021 technical session.
b. Please refer back to response to **DOE 3-001: c.**
c. Please refer back to response to **DOE 3-001: d.**

Below is a line item breakdown of the cost and time estimate discussed in the response to DOE 3-008 - EV 3 Part TOU Rate

Cost Category	Category Description	Q1-Year1	Q2-Year1	Q3-Year1	Q4-Year1	Q1-Year2	Total
Project Management	Incremental labor costs associated with providing project oversight, governance and cost and schedule management	$327,000.00	$327,000.00	$327,000.00	$327,000.00	$327,000.00	$1,635,000.00
Requirements, Design and System Development	Incremental labor costs associated with elicitation and preparation of system requirements, designs and code development of the system being modified	$1,386,600.00	$1,386,600.00	$1,386,600.00	$1,386,600.00	$1,386,600.00	$6,933,000.00
Testing	Incremental labor costs associated with preparation of test cases, execution of testing to validate the solution is functioning as expected.	$110,400.00	$110,400.00	$110,400.00	$110,400.00	$110,400.00	$552,000.00
Totals		$1,824,000.00	$1,824,000.00	$1,824,000.00	$1,824,000.00	$1,824,000.00	$9,120,000.00

Attachment SIS-4

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-170

Date Request Received: 08/13/2021 **Date of Response: 08/27/2021**
Request No. DOE 3-001 **Page 1 of 1**
Request from: Department of Energy

Witness: Dennis E. Moore

Request:
Reference DOE 2-003 regarding meters and billing system.

a. If Eversource waits until the planned enterprise MDMS and CIS system upgrades are complete to offer a 3 period EV TOU rate, please provide details how the incremental costs of the 3 period EV TOU rate offering would vary from the $9.1M cited in testimony.
b. Please explain when Eversource expects to begin and complete the enterprise MDMS and CIS system, consistent with its Grid Mod Phase II proposal in Massachusetts.
c. Please provide details on any additional costs that would be required for the existing Eversource billing system to incorporate a 2-period EV TOU rate, with time varying generation, distribution, and transmission components. Please explain why these costs would be required since Eversource currently offers a 2-period TOU rate.
d. Please provide details on any additional costs that would be required for the existing Eversource billing system to incorporate a 2-period EV TOU rate, with time varying distribution and transmission components only. Please explain why these costs would be required since Eversource currently offers a 2-period TOU rate.

Response:
a. We anticipate the incremental cost reduction to achieve a 3 period EV TOU rate to be between 40-45%, due to the improved capabilities of the new enterprise MDM and CIS systems.
b.The Eversource Grid Mod Phase II proposal in Massachusetts for AMI shows that the Company expects to begin the MDMS in 2023 and complete it at the end of 2025 and expects to begin the CIS system in 2024 and complete it at the end of 2027.
c. The cost to implement a 2-period TOU EV versus a 3-period TOU EV with time varying generation, distribution, and transmission components is the same as this requires a billing system structural change to offer TOU generation and same level of rigor in testing the solution. Eversource utilizes one legacy customer billing system across three states and that would require the same amount of regression testing to ensure no impact to other state jurisdictions with this change.
d. Eversource currently offers 2-period TOU distribution and transmission components in existing Residential Optional-Time-Of-Day (R-OTOD) rate. If R-OTOD off-peak period is identical to 2-period off-peak period TOU EV than R-OTOD rate could be used at no additional billing system cost. Pls. Refer to Attachment 1.

Attachment SIS-5

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-170

Date Request Received: 07/21/2021 **Date of Response: 08/04/2021**
Request No. DOE 2-007 **Page 1 of 1**
Request from: Department of Energy

Witness: Edward A. Davis

Request:
Reference Exhibit ES-RDC-1 in DPU 21-90, page 18-19, describing how rate EV-1 and EV-2 were constructed.

a. Please provide the workpapers used to develop these rates, in native format (live excel, where applicable) with all equations intact.
b. Please clarify whether the Company's rate proposal in DE 21-078 was constructed in the same manner.
c. Please provide the underlying workpapers represented by Exhibit ES-RDC-2 in DPU 21-90, in native format (live excel, where applicable) with all equations intact.
d. Please indicate whether the Company expects any shifting of costs attributable to electric vehicle ownership onto non-electric vehicle owners will occur as a result of the proposed demand charge alternatives. If the company has conducted any analyses to determine the level of cost shifting at various participation levels and charging load shapes, please provide those analyses. If the company has conducted no such analyses, please explain why this is the case.

Response:
a.and c. The working spreadsheets and information requested in parts a. and c., along with Exhibit ES-RDC-1, are available through the Massachusetts Energy and Environmental Affairs link, https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bydivision, by selecting the Electric Division and Docket # 21-90 links and the corresponding files listed for the July 14, 2021 NSTAR Electric filing.
b. While the Company's rate proposal in Docket No. DE 21-078 is not presently being considered in this docket, the Company's rate proposal in Docket No. DE 21-078 was not constructed in the same manner as that referenced in NSTAR Electric Company's proposal in DPU 21-90.
d. The Company's demand charge alternative rate design is currently the subject of Docket No. DE 21-078, and not this docket. However, while there may be cost shifting between customer who receive electric service under a separate EV rate, it is premature to quantify such shifting without sufficient data for evaluation. Indicatively, under the Company's proposal, lower utilization than the level applied in rate design (i.e., 10%) would produce less revenue which could represent a reduction in cost recovery compared with application of a demand charge.

Attachment SIS-6

Comparison of Current vs Proposed
Permanent Rates

Rate GV

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	16,601	$ 194.03	$ 3,221,053	$ 211.21	$ 3,506,255	$ 285,202	8.85%
Demand 1-100 kW	1,568,428						
Distribution		$ 5.58	$ 8,751,828	$ 6.90	$ 10,822,153	$ 2,070,325	23.66%
Transmission		10.40	16,311,651	$ 10.40	16,311,651	-	0.00%
Stranded Cost Recovery Charge		0.65	1,019,478	$ 0.65	1,019,478	-	0.00%
Demand > 100 kW	2,667,694						
Distribution		$ 5.34	$ 14,245,486	$ 6.64	$ 17,713,488	$ 3,468,002	24.34%
Transmission		10.40	27,744,018	10.40	27,744,018	-	0.00%
Stranded Cost Recovery Charge		0.65	1,734,001	0.65	1,734,001	-	0.00%
Minimum Charge	123	$ 893.00	$ 110,064	$ 1,062.00	$ 130,894	$ 20,830	18.92%
Energy Charge 1 - 200,000 kWh	1,448,276,753						
Distribution		$ 0.00606	$ 8,776,557	$ 0.00656	$ 9,500,695	$ 724,138	8.25%
Transmission		-	-	-	-	-	
Stranded Cost Recovery Charge		0.00643	9,312,420	0.00643	9,312,420	-	0.00%
System Benefits Charge		0.00743	10,760,696	0.00743	10,760,696	-	0.00%
Energy Service Charge		0.06025	87,258,674	0.06025	87,258,674	-	0.00%
Energy Charge >200,000 kWh	217,399,074						
Distribution		$ 0.00509	$ 1,106,561	$ 0.00583	$ 1,267,437	$ 160,876	14.54%
Transmission		-	-	-	-	-	
Stranded Cost Recovery Charge		0.00643	1,397,876	0.00643	1,397,876	-	0.00%
System Benefits Charge		0.00743	1,615,275	0.00743	1,615,275	-	0.00%
Energy Service Charge		0.06025	13,098,294	0.06025	13,098,294	-	0.00%
Distribution Impact Only		$ 0.02174	$ 36,211,549	$ 0.02578	$ 42,940,922	$ 6,729,373	18.58%
Total Change		$ 0.12395	$ 206,463,932	$ 0.12799	$ 213,193,305	$ 6,729,373	3.26%

Rate GV - Backup Service < 115 KV

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Administrative Charge	108	$ 341.84	$ 36,919	$ 372.10	$ 40,187	$ 3,268	8.85%
Translation Charge	39	$ 57.34	$ 2,236	62.42	$ 2,434	$ 198	8.86%
Demand Charge	35,399						
Distribution		$ 4.48	$ 158,588	$ 5.37	$ 190,093	$ 31,505	19.87%
Transmission		1.59	56,284	1.59	56,284	-	0.00%
Stranded Cost Recovery Charge		0.32	11,328	0.32	11,328	-	0.00%
Energy Charge 1 - 200,000 kWh	2,778,333						
Distribution		$ 0.00606	$ 16,837	$ 0.00656	$ 18,226	$ 1,389	8.25%
Transmission		-	-	$ -	-	-	
Stranded Cost Recovery Charge		0.00643	17,865	$ 0.00643	17,865	-	0.00%
System Benefits Charge		0.00743	20,643	$ 0.00743	20,643	-	0.00%
Energy Service Charge		0.06025	167,395	$ 0.06025	167,395	-	0.00%
Energy Charge >200,000 kWh	0						
Distribution		$ 0.00509	$ -	$ 0.00583	$ -	$ -	14.54%
Transmission		-	-	$ -	-	-	
Stranded Cost Recovery Charge		0.00643	-	$ 0.00643	-	-	0.00%
System Benefits Charge		0.00743	-	$ 0.00743	-	-	0.00%
Energy Service Charge		0.06025	-	$ 0.06025	-	-	0.00%
Distribution Impact Only		$ 0.07723	$ 214,580	$ 0.09032	$ 250,940	$ 36,360	16.94%
Total Change		$ 0.17568	$ 488,095	$ 0.18877	$ 524,455	$ 36,360	7.45%

Rate GV - Backup Service > 115 KV

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Administrative Charge	-	$ 341.84	$ -	$ 372.10	$ -	$ -	8.85%
Translation Charge	-	$ 57.34	$ -	62.42	$ -	$ -	8.86%
Demand Charge	-						
Transmission		1.59	-	1.59	-	-	0.00%
Stranded Cost Recovery Charge		0.32	-	0.32	-	-	0.00%
Energy Charge On Peak	-						
Transmission		-	-	-	-	-	0.00%
Stranded Cost Recovery Charge		0.00256	-	0.00256	-	-	0.00%

89	System Benefits Charge		0.00586	-	0.00586	-	-	0.00%
90	Energy Service Charge		0.12222	-	0.12222	-	-	0.00%
91								
92	**Energy Charge Off Peak**	-						
93	Transmission		-	-	-	-	-	0.00%
94	Stranded Cost Recovery Charge		0.00171	-	0.00171	-	-	0.00%
95	System Benefits Charge		0.00586	-	0.00586	-	-	0.00%
96	Energy Service Charge		0.12222	-	0.12222	-	-	0.00%
97								
98	Distribution Impact Only		$ -	$ -	$ -	$ -	$ -	
99	Total Charge		$ -	$ -	$ -	$ -	$ -	

Demand Charge Alternative Rate Design Calculation

Rate GV: Rates Effective January 1, 2021

Class Loa 55%

Customer Charge $211.21 /month

	(A) Revenue Requirement	(B) Class Consumption	(C) = (A) / (B) Average Class Rate		
Distributic	$ 39,303,773	1,665,675,827	$ **0.02360**	/kWh	(1)
Transmiss	$ 44,055,669	1,665,675,827	**0.02645**		(2)
SCRC (de	2,753,479	1,665,675,827	**0.00165**		(3)
Total Demand			$ **0.05170**	/kWh	(4)=(1)+(2)+(3)
Total Other **			$ **0.07411**		(5)
Total			$ **0.17751**	/kWh	(6)=(4)+(5)

* Demand and volumetric revenue requirement combined
** Volumetric Energy Supply, SBC and SCRC Rates, as follows:

	Other	
SCRC	$ 0.00643	/kWh
SBC	$ 0.00743	
ES	$ 0.06025	
Total Other	$ **0.07411**	/kWh

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Test Year
	3%	5%	7%		15%	20%	25%	27%	30%	30%	55%
	18.3	11.0	7.9		3.7	2.8	2.2	2.0	1.8	1.8	1.0
	Volumetric Rate at Designated Utilization Levels ($/kWh)										
	$ 0.43260	$ 0.25956	$ 0.18540		$ 0.08652	$ 0.06489	$ 0.05191	$ 0.04807	$ 0.04326	$ 0.04326	$ 0.02360
	0.48490	0.29094	0.20781		0.09698	0.07274	0.05819	0.05388	0.04849	0.04849	0.02645
	0.03031	0.01818	0.01299		0.00606	0.00455	0.00364	0.00337	0.00303	0.00303	0.00165
	0.07411	0.07411	0.07411		0.07411	0.07411	0.07411	0.07411	0.07411	0.07411	0.07411
	$ 1.02192	$ 0.64279	$ 0.48031		$ 0.26367	$ 0.21628	$ 0.18785	$ 0.17942	$ 0.16889	$ 0.16889	$ 0.12581

Station Utilization	3%	5%	7%	10%	15%	20%	25%	27%	30%	30%
Customer	$ 211.21	$ 211.21	$ 211.21	$ 211.21	$ 211.21	$ 211.21	$ 211.21	$ 211.21	$ 211.21	$ 211.21
Volumetric (applied to all kWh)	$ 1.02192	$ 0.64279	$ 0.48031	$ 0.35845	$ 0.26367	$ 0.21628	$ 0.18785	$ 0.17942	$ 0.16889	$ 0.16889

Revenue Neutral Rate Design including Class-to-Station Utilization Adjustment

Monthly C **$211.21**

Station Utilization		10%		(7)
Rate Parity Adjustment **		5.5		(8)=(14) / (7)
		Volumetric Rate At		
Demand A	**Distribution**	$ **0.12978**	/kWh	(9)=(1)*(8)
Demand A	**Transmission**	$ **0.14547**	/kWh	(10)=(2)*(8)
Demand A	**SBC**	$ 0.00909	/kWh	(11)=(3)*(8)
Volumetric	**Other***	$ **0.07411**	/kWh	(12)=5)
Total Alterr	**Total**	$ **0.35845**	/kWh	(13)=(9)+(10)+(11)+(12)

* See "Total Other"
** Ratio of class load factor to station utilization (i.e., target utilization level)
Class Load Factor: 55% (14)

Demand Charge Alternative Rate Summary

Monthly Customer Charge **$211.21**
Volumetric Charge **35.845 cents/kWh**

Attachment SIS-7

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 20-170
Electric Vehicle Time of Use Rates

Staff Data Requests - Set 2

Date Request Received: 7/21/21
Request No. DOE 2-5

Date of Response: 8/4/21
Respondent: Heather Tebbetts
Melissa Samenfeld

REQUEST:

Reference Response Staff 1-3, stating "The Company did not propose an EV TOU rate for its commercial rates," and Order No. 26, 394 (August 18, 2020) stating "Staff recommended the Commission open a new proceeding and direct each electric utility to file within 120 days, consistent with the guidance above: (1) an EV TOU rate proposal for separately-metered residential and small commercial customer applications; (2) an EV TOU rate proposal for separately-metered high demand draw commercial customer applications that may incorporate direct current fast charging or clustered level two chargers."

a. Please explain why the Company did not develop an EV TOU rate proposal for separately-metered high demand draw commercial customer applications.
b. Please explain why the Company could not utilize the same method it used to develop EV TOU rates for residential and small commercial customers, and develop a EV TOU rate for high demand draw commercial customer applications.

RESPONSE:

a. The Company does not agree that offering EV TOU rates for separately-metered high demand draw commercial applications is the appropriate rate design for such electric vehicle charging installations.
b. The premise of the residential rate is completely different than separately metered commercial customer applications. Residential customers will charge when they are home, most likely on the weekends and evenings, thus charging during off peak hours. Commercial applications provide charging for any time during the day when drivers are out in the community and need to charge; thus, completely different use cases are being compared in the question.

Attachment SIS-8

Liberty Utilities (Granite State Electric) d/b/a Liberty
Rate EV-L

		Rate G-1 Billing Determinants	Rate G-1 Current Revenues	Rate G-1 Current Rates	Percent Split By Charge	Proposed % Split by Charge	Proposed Revenues	Proposed Rates
		(a)	(b)	(c.)	(d)	(e)	(f)	(g)
1	Customer Charge	1,742	$747,091	$428.76	6.98%	5.00%	$534,883	$307.05
2	kWh	367,232,595	$1,293,482	$0.00352	12.09%	85.00%	$9,093,009	$0.02476
3	kW	951,328	$8,657,085	$9.10	80.93%	10.00%	$1,069,766	$1.12
4		Total	$10,697,658			Total	$10,697,658	

a Billing determinants from DE 19-064 test year
b Current rates multiplied by billing determinants in (a)
c Current rates
d Line 1 / Line 4
e Percent split
f (e.) x (b)
g (f) / (a)

Liberty Utilities (Granite State Electric) d/b/a Liberty
Rate EV-M

		Rate G-2 Billing Determinants	Rate G-2 Current Revenues	Rate G-2 Current Rates	Percent Split By Charge	Proposed % Split by Charge	Proposed Revenues	Proposed Rates
		(a)	(b)	(c.)	(d)	(e)	(f)	(g)
1	Customer Charge	10,558	$754,606	$71.47	13.21%	5%	$285,561	$27.05
2	kWh	125,159,740	$289,119	$0.00231	5.06%	85%	$4,854,539	$0.03879
3	kW	510,109	$4,667,497	$9.15	81.73%	10%	$571,122	$1.12
4		Total	$5,711,222			Total	$5,711,222	

a Billing determinants from DE 19-064 test year
b Current rates multiplied by billing determinants in (a)
c Current rates
d Line 1 / Line 4
e Percent split
f (e.) x (b)
g (f) / (a)

Attachment SIS-9

Large Customer Group
Rates G-1 and G-2
Illustrative Weighted Average Energy Service Rates For Comparison Purposes Only
February 2021 - July 2021

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
DE 20-053 Energy Service Reconciliation
Schedule AMH/DBS-1 Rates
Page 1 of 1

REDACTED

	Section 1: Percentage of Medium and Large C&I kWhs Attributable to Energy Service							
1	September 2020 Medium and Large C&I Energy Service kWhs	8,495,105						
2	September 2020 Total Medium and Large C&I kWhs	43,935,731						
3	Percentage of Medium and Large C&I Energy Service kWhs to Total Medium and Large C&I kWhs	19.34%						
	Section 2: Projected Medium and Large C&I Default Service kWhs, February 2021 - July 2021							
		February	March	April	May	June	July	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
4	Projected Total Company Medium and Large kWhs	37,608,421	41,625,419	39,959,273	42,893,135	45,631,756	50,397,959	258,115,964
5	Percentage of Medium and Large C&I Energy Service kWhs to Total Medium and Large C&I kWhs	19.34%	19.34%	19.34%	19.34%	19.34%	19.34%	
6	Projected Medium and Large C&I Energy Service kWhs	7,271,701	8,048,399	7,726,245	8,293,516	8,823,036	9,744,596	49,907,494
	Section 3: Medium and Large C&I Default Service Load Weighting for February 2021 - July 2021							
7	Projected Medium and Large C&I Energy Service kWhs	7,271,701	8,048,399	7,726,245	8,293,516	8,823,036	9,744,596	49,907,494
8	Loss Factor	[redacted]						
9	Wholesale Contract Price ($/MWh)							
10	Base Energy Service Rate ($/kWh)	$0.07799	$0.06803	$0.06003	$0.05533	$0.05109	$0.05460	
11	Energy Service Reconciliation Adjustment Factor ($/kWh)	($0.00378)	($0.00378)	($0.00378)	($0.00378)	($0.00378)	($0.00378)	
12	Energy Service Cost Reclassification Adjustment Factor ($/kWh)	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	
13	Renewable Portfolio Standard Adder ($/kWh)	$0.00859	$0.00859	$0.00859	$0.00859	$0.00859	$0.00859	
14	Total Estimated Medium and Large C&I Energy Service Price per kWh	$0.08361	$0.07365	$0.06565	$0.06095	$0.05671	$0.06022	

1 Per Monthly Energy Service Revenue Reports (Rates G-1 and G-2)
2 Per Monthly Total Revenue Reports (Rates G-1 and G-2)
3 Line (1) ÷ Line (2)
4 Per Company forecast for medium and large C&I rates (Rates G-1 and G-2)
5 Line (3)
6 Line (4) x Line (5)
7 Line (6)
8 Projected Wholesale Load divided by Projected Retail Load, rounded to five decimal places
9 Schedule JDW-2 Exhibit 5
10 Line (8) x Line (9) / 1000, truncated to five decimal places
11 Schedule AMH/DBS-5 Page 1, Line 6, filed in April 2020
12 Schedule AMH/DBS-6 Page 1, Line 5, filed in April 2020
13 Schedule JDW-2 Exhibit 11
14 Line (10) + Line (11) + Line (12) + Line (13)

Attachment SIS-10

Large Customer Group
Rates G-1 and G-2
Illustrative Weighted Average Energy Service Rates For Comparison Purposes Only
August 2021 - January 2022

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
DE 21-087 Energy Service Reconciliation
Revised Schedule AMH/DBS-1 Rates
Page 1 of 1

REDACTED

		August (a)	September (b)	October (c)	November (d)	December (e)	January (f)	Total (g)
	Section 1: Percentage of Medium and Large C&I kWhs Attributable to Energy Service							
1	March 2021 Medium and Large C&I Energy Service kWhs	8,069,427						
2	March 2021 Total Medium and Large C&I kWhs	39,528,385						
3	Percentage of Medium and Large C&I Energy Service kWhs to Total Medium and Large C&I kWhs	20.41%						
	Section 2: Projected Medium and Large C&I Default Service kWhs, August 2021 - January 2022							
4	Projected Total Company Medium and Large kWhs	50,201,834	44,230,582	43,381,984	40,972,721	41,336,151	42,197,264	262,320,536
5	Percentage of Medium and Large C&I Energy Service kWhs to Total Medium and Large C&I kWhs	20.41%	20.41%	20.41%	20.41%	20.41%	20.41%	
6	Projected Medium and Large C&I Energy Service kWhs	10,248,333	9,029,346	8,856,111	8,364,278	8,438,469	8,614,259	53,550,794
	Section 3: Medium and Large C&I Default Service Load Weighting for August 2021 - January 2022							
7	Projected Medium and Large C&I Energy Service kWhs	10,248,333	9,029,346	8,856,111	8,364,278	8,438,469	8,614,259	53,550,794
8	Loss Factor	[redacted]						
9	Wholesale Contract Price ($/MWh)							
10	Base Energy Service Rate ($/kWh)	$0.05768	$0.05411	$0.05582	$0.06842	$0.08840	$0.11180	
11	Energy Service Reconciliation Adjustment Factor ($/kWh)	$0.00146	$0.00146	$0.00146	$0.00146	$0.00146	$0.00146	
12	Energy Service Cost Reclassification Adjustment Factor ($/kWh)	($0.00115)	($0.00115)	($0.00115)	($0.00115)	($0.00115)	($0.00115)	
13	Renewable Portfolio Standard Adder ($/kWh)	$0.00684	$0.00684	$0.00684	$0.00684	$0.00684	$0.00684	
14	Total Estimated Medium and Large C&I Energy Service Price per kWh	$0.06483	$0.06126	$0.06297	$0.07557	$0.09555	$0.11895	

1 Per Monthly Energy Service Revenue Reports (Rates G-1 and G-2)
2 Per Monthly Total Revenue Reports (Rates G-1 and G-2)
3 Line (1) ÷ Line (2)
4 Per Company forecast for medium and large C&I rates (Rates G-1 and G-2)
5 Line (3)
6 Line (4) x Line (5)
7 Line (6)
8 Projected Wholesale Load divided by Projected Retail Load, rounded to five decimal places
9 Schedule JDW-2 Exhibit 5
10 Line (8) x Line (9) / 1000, truncated to five decimal places
11 Schedule AMH/DBS-5 Page 1, Line 6
12 Schedule AMH/DBS-6 Page 1, Line 5
13 Schedule JDW-2 Exhibit 11
14 Line (10) + Line (11) + Line (12) + Line (13)

Attachment SIS-11

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Transmission Charge Calculation

		Total	D	D-10	G-1	G-2	G-3	Streetlights	T	V
[1]	**Estimate of Transmission Expense**	**$26,891,183**								
[2]	**Coincident Peak (KW)**	1,749,718	646,190	9,330	655,684	261,052	149,209	4,909	22,884	460
[3]	**Coincident Peak Allocator**	100.00%	36.93%	0.53%	37.47%	14.92%	8.53%	0.28%	1.31%	0.03%
[4]	**Allocated Transmission Expense**	$26,891,183	$9,931,208	$143,392	$10,077,120	$4,012,073	$2,293,173	$75,446	$351,701	$7,070
[5]	**Forecasted kWh Sales**	879,426,489	284,513,526	5,441,648	367,232,595	125,159,740	79,307,937	3,836,676	13,619,228	315,138
[6]	**Proposed Transmission Charge per kWh**	**$0.03057**	**$0.03490**	**$0.02635**	**$0.02744**	**$0.03205**	**$0.02891**	**$0.01966**	**$0.02582**	**$0.02243**
[7]	**Current Transmission Charge per kWh**	$0.02545	$0.02834	$0.02443	$0.02239	$0.02727	$0.02724	$0.01694	$0.02794	$0.02675
[8]	**Increase (Decrease) in Transmission Charge per kWh**	**$0.00512**	**$0.00656**	**$0.00192**	**$0.00505**	**$0.00478**	**$0.00167**	**$0.00272**	**($0.00212)**	**($0.00432)**

[1] Schedule JDW-1, Line (10)
[2] Schedule DBS/AMH-3, Page 2 of 7
[3] Line (2) as a percent of total Line (2)
[4] Line (1) x Line (3)
[5] Per Company Forecast
[6] Line (4) ÷ Line (5), truncated after 5 decimal places
[7] Per Currently Effective Tariffs
[8] Line (6) - Line (7)

Attachment SIS-12

Liberty Utilities (Granite State Electric) d/b/a Liberty
Revenues by Month July 2020 through June 2021[a]

	July-20	August-20	September-20	October-20	November-20	December-20	January-21	February-21	March-21	April-21	May-21	June-21
Distribution	$3,023,654.17	$3,023,076.48	$2,416,749.90	$3,486,550.93	$3,506,457.78	$3,897,635.80	$4,094,153.35	$3,980,761.83	$3,957,252.82	$3,627,157.77	$3,373,800.88	$3,990,607.68
Transmission	$2,125,004.50	$2,087,434.98	$1,793,853.32	$1,580,209.10	$1,555,264.57	$1,802,766.60	$1,919,525.50	$1,824,123.24	$1,825,117.67	$1,674,738.93	$1,769,633.78	$2,536,014.78
Energy Service	$4,090,433.63	$4,431,866.60	$3,853,545.38	$2,003,541.83	$2,116,486.23	$2,669,518.28	$3,096,351.70	$2,944,230.11	$2,707,082.00	$2,264,243.28	$1,883,613.19	$2,360,656.42
Total	$9,239,092.30	$9,542,378.06	$8,064,148.60	$7,070,301.86	$7,178,208.58	$8,369,920.68	$9,110,030.55	$8,749,115.18	$8,489,452.49	$7,566,139.98	$7,027,047.85	$8,887,278.88

[a] Quarterly NHPUC F-1 filing

Attachment SIS-13

Request:

Reference the Commission's October 16, 2020 Order of Notice in this proceeding, describing the issues noticed in this proceeding as including "whether the EV TOU rate proposals to be developed and filed are consistent with the rate design standards delineated in Order No. 26,394; whether those EV TOU rate design proposals are likely to result in just and reasonable electric rates, as required by RSA 374:2 and RSA 378:5 and :7; and whether the EV TOU rate design proposals are consistent with the New Hampshire Energy Policy defined in RSA 378:37."

a. Please explain whether the Company believes the EV Program Infrastructure Proposal discussed at Carroll, Simpson, Valianti testimony pages 28-44 is consistent with Commission's October 16, 2020 Order of Notice.
b. Please explain whether the Company's EV Program Infrastructure Proposal discussed at Carroll, Simpson, Valianti testimony pages 28-44 is expected to have an impact on current rates and revenues. If so, please explain why percentage revenue impact is not detailed in the cover letter of this proceeding consistent with Puc 1605.02(a)(l).

Response:

a. The Company believes that the EV Program Infrastructure Proposal is consistent with the Commission's October 16, 2020 Order of Notice. In Order 26,394, the Commission found that "further investigation of issues related to advanced metering functionality associated with EVSE embedded meters is warranted" and directed Staff to further this concept. Order 26,394 at 13-14. The Company believes that in order to understand measurement functionalities offered by EVSE embedded meters, experience with associated data is essential. In an effort to support a crucial segment of the EV charging population (i.e. at home charging), the Company has proposed to offer rebates for the installation and procurement of EVSE providing embedded metering functionality. This will provide an opportunity for the Company to engage with customers, EVSE manufacturers, and installers to understand how to deploy EVSE and how to manage embedded EVSE metering capabilities. The Company further believes that the EV Program Infrastructure Proposal is also consistent with the Order of Notice because the Company has requested approval of the program subject to the Commissions' determination that the rates are just and reasonable, subject to investigation, subject to modification, and commensurate with the least cost energy planning process, as required by RSA 374:2, 378:5, 7 and 37, respectively.

b. Yes, the Program is expected to have an impact on revenues. The Commission recognized in Order 26,486 that “Unitil’s EV TOU proposals will also be considered in Docket DE 20-170… and that resolution may inform our decision in the instant rate case.” Therefore, the Company’s expectation is that the EV Program Infrastructure Proposal will be ruled on in the Company’s base rate case Docketed in DE 21-030, not DE 20-170. The Company provided cost estimates in the rate case, however the impact on rates is dependent upon actual program spending in the future.

sagewell[SM]

Via Electronic Mail

September 14, 2021

Scott Seigal

Hearing Officer, Department of Public Utilities

One South Station, 5th Floor Boston, Massachusetts 02110

Re: DPU 21-90, DPU 21-91 and DPU 21-92 — Public Hearing and Request for Comments

Dear Hearing Officer and DPU,

Sagewell, Inc. is pleased to provide these written comments to the Department regarding dockets DPU 21-90, DPU 21-9, and DPU 21-92. We appreciate the DPU's attention to Electric vehicle (EV) load management as an important matter. Based in Cambridge, MA, Sagewell is a national leader in EV load management programs serving utilities with millions of meters. We also have active electric vehicle load management programs with several public power utilities in Massachusetts, including Braintree Electric Light Department which has a nation-leading 80% EV enrollment rate in Sagewell's Bring Your Own Charger® (BYOC) EV load management program. Sagewell has received numerous industry awards for its load management programs. Our pilot program with the Massachusetts Department of Resources also demonstrated that our BYOC program is one of the most effective EV load management programs.

Our interest is ensuring that EV programs, particularly managed charging programs and residential make-ready and EVSE rebates, are able to reach as many EV drivers as possible. Without widespread enrollment of EV drivers, load management programs will not have the desired impacts. Currently, the proposals from National Grid and Eversource rely on Wi-Fi networked Level 2 chargers for load management. While they are helpful technologies, they are unlikely to reach sufficient market share to meet the Department's load management goals and will significantly limit participation.

Approximately 90% of the battery electric vehicles sold in the U.S. in 2020 came with a manufacturer-supplied 240-volt Level 2 charging cord that plugs directly into a 240-volt outlet. These EV drivers do not need to purchase a separate Level 2 charger of any kind, and can sagewell[SM]

simply install 240-volt outlets near where they park their EVs. Our experience operating EV load management programs nationwide indicates that most EV drivers are unlikely to purchase a networked charger, and industry estimates indicate that WiFi-connected networked chargers likely have less than 10% market share nationwide.

To increase EV load management program participation, we encourage the Department to expand its definition of “managed charging capable L2 EVSE” to include telematics programs that leverage the onboard telematics systems in most EVs, and, in the future, AMI smart meter load disaggregation. Without needing specific charging hardware or in-car devices, telematics and AMI load disaggregation techniques offer the same functions as networked Level 2 chargers. To illustrate, a networked charger is a combination of a charger, an energy consumption meter, load reduction function, and a data transmitter. The same functions are delivered by the combination of any brand charging device (load controllable or not), a telematics connection (or whole-home AMI smart meter data access), and a programmable load reduction feature in the vehicle. As an example, the State of Michigan Public Service Commission has authorized its two leading investor-owned utilities to operate networked chargers, vehicle telematics, AMI load disaggregation, TOU rates, and other EV load management programs side by side.

We encourage the Department to also include passive or “every day” load shifting programs in its decisions. Our experience and data from the industry indicates that programs that are able to shift EV load every day, rather than based on specific load management events, have a greater overall impact. Passive load shifting does not require accurately monitoring and calling events.. In addition, by shifting load 5 days per week, 52 weeks per year, EDCs will increase overall savings as energy costs and carbon emissions are lowest during the overnight hours.

With regard to the Unitil proposal, passive “every day” load shifting programs can deliver better results and higher enrollment rates than time of use rates, without the barriers of shifting overall home electric use or installation of a separate meter.

We also encourage the Department to allow EDCs the flexibility to offer fixed monthly incentives rather than kilowatt hour incentives due to their very high effectiveness, and lower overall cost. The contribution of any particular EV to coincident peak demand is not closely related to the number of miles driven per year, but rather personal habits and vehicle charging rate. Allowing for fixed monthly incentives for successfully charging during off-peak hours would better align interests, greatly simplify the process, lower costs to ratepayers, and allow utility program managers to implement the most successful EV load management incentive structure.

In summary, we encourage the Department to prioritize maximizing participation when considering EV management proposals. Expanding the reach of these programs through telematics or AMI meter data disaggregation, encouraging passive load shifting programs, and allowing flexibility in incentive structures will maximize the amount of peak load shifted to off-peak hours, and the benefits for the grid, ratepayers, and EV drivers.

Thank you for your time and consideration.

Sincerely,

/s/ Gary Smith

Gary Smith
Vice President of Programs
Sagewell, Inc.

VEHICLE-GRID INTEGRATION COUNCIL

D.P.U. 21-91: Comments of the Vehicle-Grid Integration Council (VGIC) on National Grid's Proposed Phase III EV Market Development Program

I. Introduction

The Vehicle-Grid Integration Council (VGIC)[1] is a 501(c)(6) membership-based trade association committed to advancing the role of electric vehicles (EVs) and vehicle-grid integration (VGI) through policy development, education, outreach, and research. VGIC supports the transition to decarbonized transportation and electric sectors by ensuring the value from EV deployments and flexible EV charging and discharging is recognized and compensated in support of achieving a more reliable, affordable, and efficient electric grid. VGIC appreciates the opportunity to provide comments to the Department of Public Utilities (DPU) on National Grid's proposed Phase III EV Market Development Program.

II. EV Time-of-Use (TOU) Rates are Needed to Support Massachusetts's Transportation Electrification (TE) Efforts

Managed charging or "V1G" is an important tool to support TE efforts, as it shifts EV charging away from on-peak periods, which can help lower overall charging costs and support the grid.EV TOU rates are one of the most effective V1G strategies to shift EV charging. While VGIC is generally supportive of National Grid's Off-Peak Charging Rebate, including the proposed flexible scheduling and eligibility expansion to fleet customers, time-varying EV rates can unlock a far greater level of load flexibility from EVs.

For example, with the off-peak charging rebate, a residential customer receiving delivery service and fixed price supply from National Grid would pay 26.787 cents/kWh for on-peak charging, and 21.787 or 23.787 cents/kWh for off-peak charging (depending on the season), resulting in a 1.13:1 to 1.23:1 differential between on- and off-peak charging rates.[2] For

[1] VGIC member companies and supporters include American Honda Motor Co., Inc., dcbel, Enel X North America, Inc., Fermata, LLC., FlexCharging, Inc., Ford Motor Company, General Motors Company, Nissan North America, Inc., Nuvve Corporation, Stellantis N.V., The Mobility House, Toyota Motor North America, Inc., and Veloce Energy, Inc. The views expressed in these comments are those of VGIC, and do not necessarily reflect the views of all individual VGIC member companies or supporters. (https://www.vgicouncil.org/).
[2] Using rates from National Grid's 2019 Summary of Rates. https://www.nationalgridus.com/media/pdfs/billing-payments/electric-rates/ma/cm4394_maweb.pdf

comparison, Pacific Gas & Electric's EV-B rate offers a 4:1 on- and off-peak differential,[3] while Xcel Energy Minnesota's A08 – Residential EV Service offers a roughly 4:1 to 5:1 differential.[4] A similarly designed EV TOU rate would present more dynamic price signals and more effectively encourage customers to shift EV charging away from on-peak periods. Notably, the proposed demand charge alternative is not a load management strategy and therefore is not a substitute for such EV TOU rates.

In addition, an off-peak charging incentive may not be a sustainable mechanism to encourage beneficial charging behavior. While a rebate for off-peak charging would be an acceptable first step in exploring financial incentives for off-peak charging, its continuation is dependent upon subsequent funding decisions by the Department. On the other hand, EV TOU rates can be designed to be revenue neutral and appropriately recover utility costs, and thus do not require additional ratepayer funding. When approving the off-peak charging rebate in 2018, the Department stated that the rebate would allow National Grid to "gain experience and gather data necessary to develop new time-of-use rates for EV customers in the future." VGIC believes that sufficient time has passed since this decision for National Grid to have gathered the necessary data to develop EV TOU rates. EV TOU rates are a necessary long-term tariff offering, and VGIC urges the Department to direct National Grid to file proposals for EV TOU rates for residential and commercial customers 6 months from the approval of its proposed Phase III EV Program.

III. Submetering via EV supply equipment (EVSE) and vehicle telematics should be utilized to support billing for EV TOU rates

The absence of advanced metering infrastructure (AMI) need not delay progress on EV TOU rates, as existing EVs and EV supply equipment (EVSE) are capable of measuring charging for the purposes of billing. To unlock this capability, EV TOU rates, off-peak charging incentives, and any other TE incentive related to charging behavior should allow submetering via the EVSE or vehicle telematics. While both National Grid and Eversource have expressed concerns over metering accuracy related to using smart chargers and vehicle telematics, VGIC notes that these

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[3] PG&E. Electric Vehicle Rate Plans. https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/electric-vehicle-base-plan/electric-vehicle-base-plan.page. Pacific Gas & Electric's EV-B rate includes charges of 56 cents/kWh during on-peak periods and 14 cents/kWh during off-peak periods – a 4:1 on- and off-peak differential.

[4] Xcel Energy Minnesota Electric Rate Book. Rate Code A08. https://www.xcelenergy.com/staticfiles/xn/Regulatory%20&%20Resource%20Planning/Minnesota/Me_Section_5.pdf. Xcel Energy Minnesota's A08 – Residential EV Service includes charges of 16.508-20.497 cents/kWh during on-peak periods and 4.170 cents/kWh during off-peak periods – a 3.96:1 to 4.92:1 differential.

potential issues are based on flawed and out-of-date studies and less paramount than the benefits that these technologies can deliver. In fact, EVSE and vehicle telematics submetering capabilities are found in commercially available products and are in use today. Notably, FERC recently approved the CAISO's methodology for EVSE submetering.[5] Xcel Energy Minnesota has implemented the Residential EV Service Pilot since 2018, using the metering capability of smart chargers to allow residential customers to enroll in EV TOU rates, and the Pilot was made a permanent program offering in 2020.[6] The Department itself has also directed National Grid and Eversource's proposals for demand charge alternatives to allow EV charging data for billing purposes to be collected via smart or networked chargers and EV telematics.[7]

Enabling EV- or EVSE-based submetering approaches help avoid the cost of a second meter, which may be borne by the customer or socialized to all of a given utility's customers - however, either approach would disproportionately impact low-income customers. For instance, allowing submetering through the charger has helped participants in Xcel Minnesota's Residential EV Service Pilot save an average $2,196 each in upfront costs.[8] Furthermore, Eversource is already proposing to provide rebates for customers installing networked Level 2 EVSE,[9] and networked EVSE and vehicle telematics are already used by National Grid and Eversource to enable EVs to participate in the Active Demand Reduction demand response program[10]. It would be a missed opportunity if such capabilities are not fully leveraged to support billing for EV TOU rates as well. As such, VGIC strongly recommends the Department direct Eversource to develop EV TOU rates that offer customers the option to elect EV- and EVSE-based measurement in lieu of installing a separate meter.

IV. National Grid's School Bus Offering Should Include a Vehicle-to-Grid (V2G) Component

Electric school buses are ideal candidates for V2G use cases due to their large batteries and operational schedules. For example, the V2G-capable electric bus from Blue Bird has 155

[5] *Order Accepting Tariff Revisions* issued on September 30, 2020 in Docket No. 20-2443-000 at 8. http://www.caiso.com/Documents/Sep30-2020-LetterOrderAcceptingEnergyStorageandDistributedEnergyResourceStakeholderESDERPhase3-ER20-2443.pdf
[6] Minnesota PUC. October 6, 2020. *Order Approving EV Home Service and Voluntary EV Charger Service Programs as Modified*. Docket 19-559.
[7] DPU 20-69-A, pg. 42. 2021.
[8] Xcel Energy Minnesota. 2020. *Annual EV Report*, pg. 11-12. Docket 17-817.
[9] Eversource Exhibit NG-EVPP-1. Docket 21-91.
[10] Massachusetts Three-Year Energy Efficiency Plan 2019-2021, Appendix K. https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf

kWh of battery capacity,[11] while the Thomas Built Buses Saf-T-Liner C2 Jouley has up to 226 kWh of battery capacity.[12] If used to offset site electric load or dispatched to support local or system grid needs, electric school buses would provide meaningful benefits to both EV customers/EVSE sites hosts and non-EV ratepayers. Notably, school buses may not have a primary customer mobility obligation during summer months, and therefore have greater availability to support summer peak reliability needs, thereby presenting a potentially low-cost method for reducing systemwide capacity costs. Compensating V2G services would also unlock an additional revenue stream for school districts, mitigating the costs of bus electrification and, in turn, accelerating TE. Given the range of benefits school bus V2G can offer, National Grid should include a V2G component in its school bus offering. Example strategies that can facilitate adoption and use of V2G technology include:

A. Ensuring V2G EVs and EVSE are eligible for the school bus rebate and any other relevant TE incentives;
B. Offering incentives to cover incremental upfront or ongoing costs of V2G (e.g., incremental cost of V2G EVSE, V2G management services, electrical equipment needed to facilitate backup power use case);
C. Offering a reasonable ongoing compensation level for V2G use (e.g., compensation for V2G exports) that provides systemwide grid benefits to all ratepayers.

VGIC notes that the City of Beverly has been partnering with Highland Electric Transportation to use electric school buses to provide V2G services in National Grid territory.[13] National Grid should build on this experience and expand V2G offerings to school districts that receive rebates for electric school buses under the proposed EV Program.

V. Automated Load Management Should be Enabled and Incorporated into Advisory Services

Automated Load Management (ALM) is the use of software or other behind-the-meter technologies to strategically share charging capacity across multiple charging ports at the same charging site, helping safely connect multiple charging ports whose total nameplate load would

[11] Nuvve Corporation. Blue Bird Delivers North America's First-Ever Commercial Application of Vehicle-to-Grid Technology in Electric School Bus Partnership with Nuvve and Illinois School Districts. March 23, 2021. https://nuvve.com/blue-bird-v2g-electric-bus-with-nuvve-and-illinois-school-districts/
[12] Thomas Built Buses / Daimler Trucks North America LLC (2021). The Safe-T-Liner C2 Jouley Electric School Bus. Retrieved September 1, 2021 from https://thomasbuiltbuses.com/school-buses/saf-t-liner-c2-jouley/
[13] Rewnewable Energy World. 2020. "Start-up bets on new model for putting electric school buses on the road." https://www.renewableenergyworld.com/2020/11/02/start-up-bets-on-new-model-for-putting-electric-school-buses-on-the-road/#gref

otherwise exceed the rated capacity of the customer connection. By using ALM, customers can avoid or defer the need to upgrade certain distribution system infrastructure to accommodate the new EV charging load. For example, if a multi-unit dwelling seeks to deploy a charging station with 5 ports, each with a 10-kW capacity, the distribution upgrades would normally be sized to accommodate 50 kW of incremental coincidental charging demand, equal to all 5 ports charging at full capacity. However, ALM can lower the coincident charging demand to below 50 kW even when all 5 ports are occupied, thus reducing distribution system upgrades to what is required for only 3 or 4 ports. In this scenario, when fewer ports are occupied, the EVs can still charge at full speed. ALM can lead to significant savings and ensure that investments in transportation electrification are used efficiently. Pacific Gas & Electric has worked with EV service providers to implement ALM solutions at 20 multi-unit dwelling and workplace host sites as of Q4 2020 and saved between $30,000 and $200,000 per project.[14] Southern California Edison also worked with PowerFlex to implement ALM to deploy 168 charging stations at $3,000 per port, significantly less than comparable deployments at $10,000-$15,000 per port without ALM.[15]

Moreover, many low-income and other disadvantaged communities are served by outdated utility infrastructure (substations, transformers) that may require significant and costly upgrades to be able to accommodate EV charging load. The use of ALM can help mitigate these infrastructure upgrade costs, therefore making charging infrastructure more affordable for disadvantaged communities. ALM is a VGI technology that is particularly well-suited for multi-unit dwellings (MUDs), commercial buildings, workplace charging, and other non-single family home sites, where low-income customers may be more likely to charge.

ALM would reduce the amount of infrastructure upgrades needed and thus lower the costs of fleet electrification and of preparing a MUD site for EV charging. As such, VGIC recommends National Grid ensure that ALM is available to customers as an option and that ALM is fully incorporated into the proposed Fleet Assessment Services and EV Ready Site Plans. It is critical that EV advisory services fully inform customers of all cost reduction measures available to them, including ALM.

VI. Managed Charging Offerings Should Center the Customer

The customers must be at the center of any managed charging or load management program. If program incentives are not attractive or visible enough to customers, participation will be low, and the offerings will fail to deliver grid and ratepayer benefits. To the extent that

[14] Pacific Gas & Electric. 2021. Presentation at CPUC ALM/EV EMS Workshop, Panel 2.
[15] EPIC Policy + Innovation Coordination Group. 2021. *Transportation Electrification Workstream Report*. https://epicpartnership.org/resources/Transportation_Electrification_Workstream_Report_Final.pdf

customers are willing and able to participate in any voluntary load management activities, they will be reducing distribution system costs for all utility customers and therefore should be rewarded accordingly. VGIC suggests that these programs include appropriate customer incentives, akin to Massachusetts' long-standing approach towards funding energy efficiency and demand-side management activities.

Additionally, the Department should consider allowing customers to simultaneously participate in multiple managed charging offerings, rather than requiring them to choose between different options. This would not only maximize customer value but also leverage EV batteries across the off-peak charging rebate, flexible scheduling, demand response (i.e., Active Demand Reduction), and other incentive programs to provide multiple benefits to the grid.

Lastly, the benefits of participation in load management offerings must be effectively communicated to customers in order to ensure high enrollment rates. National Grid should consider partnering with OEMs and EV service providers for this communication, since they are effective messengers regarding EV products and services.

VII. Conclusion

VGIC appreciates the opportunity to provide these comments and looks forward to working with National Grid, the Department, and other stakeholders to ensure the success of Massachusetts's transportation electrification efforts.

Respectfully submitted,

Zach Woogen

Vehicle-Grid Integration Council (VGIC)

vgicregulatory@vgicouncil.org

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 21-91

DIRECT PRE-FILED TESTIMONY OF THE ELECTRIC VEHICLE PROGRAM PANEL

RISHI SONDHI

JULIA GOLD

AND

JAKE NAVARRO

ON BEHALF OF
MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY EACH D/B/A NATIONAL GRID

EXHIBIT NG-EVPP-1

July 14, 2021

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exist. If no DCFC have been installed or are planned for installation within or in close proximity to the identified communities, the Company proposes to build, own, and operate up to (20) 150-kW DCFC ports across these targeted areas during the final two years of the Program. Prior to the Company building DCFC in EJCs, a six-month notice would be provided to station developers to highlight these EJC gaps and give them the opportunity to deploy DCFC prior to the Company doing so. The Company aims to collaborate with these EJCs and other stakeholders to identify sites for deployment, such as municipal public parking, commercial properties with willing site hosts, or other areas that are highly trafficked or easily accessible to the community being served.

Pole-Mounted EVSE Offering

Q. Please provide an overview of the Company's proposed pole-mounted EVSE offering.

A. The Company is proposing to install, own and operate, pole-mounted EVSE, which are charging stations mounted on electric distribution poles, located near on-street parking locations. The Company proposes to work with up to 10 municipalities to deploy approximately 200 ports on Company-owned electric distribution poles over four years. After four years of the Program, the Company will offer to sell the pole-mounted EVSE to the municipality or the open market thereafter.

To ensure that the pole-mounted EVSE will reach underserved customers, the Company will target at least five EJCs. The Company will require the partnership of the municipality to identify suitable poles that will minimize the amount of make-ready infrastructure needed and ensure the ports are sited in areas where customers with on-street parking are most likely to have access to the chargers. Eligibility criteria for the municipalities participating in the pilot include, but are not limited to, willingness to partner with the Company to deploy the chargers and compliance with agreements of other existing third-party attachments on poles or commit to being compliant with existing agreement by the end of the Company ownership period. The costs for the Company-owned pole-mounted EVSE offering are detailed in Exhibit NG-EVPP-6.

Q. What are the benefits of pole-mounted EVSE?

A. Pole-mounted EVSE will serve our customers that do not have access to private or designated parking. Customers without access to private or designated parking are more likely to live in a rented space in MUDs and customers who live in MUDs are also more likely to live in an EJC.[46] Therefore, deploying pole-mounted EVSE in EJCs can increase equitable access to EV charging. This solution will allow the Company to supplement the Public and Workplace segment offering to better address the EV charging needs in our service territory.

Q. Has the Company conducted any pole-mounted demonstration projects?

A. Yes. The Company is conducting a demonstration project of pole-mounted EVSE through a partnership with the City of Melrose. The demonstration uses Company-owned electric distribution poles, which carry the electric wires throughout the city, meaning that

[46] Company analysis of customer data and expected EJC areas.

electricity to power the charger is available directly on the pole.[47] The project in Melrose includes 15 chargers on nine poles. The chargers are designed to accommodate a single or dual charger on each pole. To date, eight chargers have been deployed and the remaining chargers are planned to be deployed by Fall 2021.

Q. Are there any initial findings or lessons learned from the demonstration project in the City of Melrose?

A. Yes. Initial results show an approximately 70% reduction in installation costs compared to ground-mounted chargers, supporting the Company's hypothesis that pole-mounted EVSE would reduce installation costs because the electric infrastructure to power the chargers is pre-existing on the distribution pole. Additional learnings from the partnership with Melrose also exposed the complex processes for third-party pole attachments. Third-party pole attachments require several highly specialized tasks for which the City of Melrose was not equipped with the necessary personnel and therefore the Company provided the necessary support to complete the process. In addition, the City of Melrose incurred several addition costs[48] to comply with the third-party attachments process. Asking future municipalities to follow the same third-party attachments process may be burdensome to the municipalities and hinder scaling up this product. Therefore, the Company is proposing to install, own and operate pole-mounted EVSE.

[47] In Massachusetts, the streetlighting infrastructure is only designed to support the voltage needed for lighting and is not able to support a charging station without costly rewiring. For this reason, installing pole-mounted chargers is simplest to install on utility electric distribution poles.

[48] Such as surety bonds and insurance requirements of the third-party attachments.

Q. Why is the Company best positioned to install, own, and operate pole-mounted EVSE?

A. The Company has many years of experience attaching products to our distribution poles and is not subject to the third-party attachments process. Therefore, the Company is in a unique position to own and operate EVSE mounted on Company-owned distribution poles. After a period of four years, the Company will offer to sell the EVSE to the municipality or to the open market, with the municipality having right of first refusal. The Company will work closely with the municipality to coordinate the transfer of the pole-mounted EVSE and expects the transition to be similar in scope to the ownership transfer of streetlights. Company ownership of pole-mounted EVSE will achieve three major benefits for customers. First, the Company will take on the risk of installing EVSE targeting areas with on-street parking that may not be financially feasible for the open market to install. Second, the Company will manage the pole attachments process, which eliminates costs of adhering to the third-party attachments process because the Company is not subject to the third-party attachment requirements for Company-owned attachments to poles. The Company will have the right to install the pole-mounted EVSE at its own discretion on jointly-owned poles because the equipment will be Company-owned. The Company will alert the joint-owner of the installation of the pole-mounted EVSE to ensure the all parties stay up to date on the equipment added to jointly-owned poles. Lastly, the Company's ownership of the pole-mounted EVSE will significantly decrease the timeline to deployment because the pole-mounted EVSE is no longer subject to the third-party attachments process, ensuring that the EVSE is available to customers in the shortest timeline possible. As station utilization increases, the Company expects that the participating municipalities and/or open market will be financially motivated to purchase the EVSE from the Company.

Q. How will the Company determine the price a customer pays to charge their vehicle at the Company-owned pole-mounted EVSE?

A. The Company will work closely with the municipal partners to address the specific needs of the municipality. At a minimum, pricing will be set to recover costs of the electricity. Working closely with the municipality will also allow the Company to address parking policies, access controls, or priorities the city or town is looking to support.

Co-located Energy Storage Incentives

Q. Is the Company proposing incentives to support the use of energy storage technology to enable expedited installation of EV fast charging in locations with existing grid constraints?

A. Yes, the Company is proposing to offer incentives to support DCFC and energy storage integrated technologies. This proposal will incentivize energy storage integrated with DCFC to reduce short to medium term barriers to the installation of high powered DCFCs in areas which provide considerable value to EV drivers due to their proximity to major thoroughfares but where current distribution system capacity may be insufficient to support DCFC sites without a system upgrade. Where the traditional wires solutions to alleviate these capacity constraints present both high system modification costs and multi-year implementation timeframes, the Company proposes offering additional incentives to

Exhibit NG-EVPP-6 Estimated Company-Owned Pole-Mounted EVSE Offering Costs

Line	**Assumptions**		***Source***
1	% of L2 ports receiving utility work	100%	*Company Assumption*
2	% of pole-mounted EVSE in LMI/EJ Communities	50%	*Company Assumption*
3	% of EVSE Cost	100%	*Company Assumption*
4	% Cost Share for Utility Side Make-Ready	100%	*Company Assumption*
5	% of Public L2 that are pole-mounted EVSE	9.20%	*Company Assumption*

Line	**Total Port Commitments**	2022	2023	2024	2025	Total	Source
6	% Port Commitments Deployed	12.0%	24.0%	36.0%	28.0%	100.0%	*Company Assumption*
7	Public L2 Ports	295	589	884	687	2,455	*From NG-EVPP-5*
8	Public L2 that are pole-mounted EVSE	27	54	81	63	225	*= Line 5 x Line 7*

Line	**Ports in LMI/EJC**	2022	2023	2024	2025	Total	Source
9	Public L2 that are pole-mounted EVSE	14	27	40	32	113	*= Line 2 x Line 8*

Line	**Infrastructure Costs per Port Comparison**	Utilty Pole EVSE	Ground Mounted EVSE	Percent Difference	Source
10	L2 Utility Make-Ready $/port	$ 675	1,456	-54%	*Company Assumption*
11	L2 Customer Premise Make-Ready $/port	$ 1,593	6,000	-73%	*Company Assumption*
12	L2 EVSE Cost $/port	$ 3,895	3,000	30%	*Company Assumption*
13	Total	$ 6,163	10,456	-41%	*= Line 10 + Line 11 + Lir*
14	Pole-mounted L2 Networking Cost/port/year	$ 300			*Company Assumption*
15	Pole-mounted L2 Maintenance Cost/port/year	$ 100			*Company Assumption*

Total Budget

Line		2022	2023	2024	2025	Total	Source
16	Pole-mounted L2 Infrastructure Costs (Capital)	$ 166,401	$ 332,802	$ 499,203	$ 388,269	$ 1,386,675	*= Line 8 x Line 13*
17	Pole-mounted L2 Networking and Maintenance Costs (O&M)	$ 10,800	$ 32,400	$ 64,800	$ 90,000	$ 198,000	*= Line 8 x (Line 14 + Lin*
18	***Total Program Cost****	**$ 177,201**	**$ 365,202**	**$ 564,003**	**$ 478,269**	**$ 1,584,675**	*= Line 16 + Line 17*

* Not including related costs in other exhibits, including Staffing, IT, and Evaluation