UNITIL ENERGY SYSTEMS, INC.

REBUTTAL TESTIMONY

OF

JOHN D. TAYLOR

MANAGING PARTNER
ATRIUM ECONOMICS, LLC

New Hampshire Public Utilities Commission

Docket No. DE 20-170

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Rebuttal Testimony of John D. Taylor

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400 Hilton Head Island SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of Unitil Energy Systems Inc. ("UES" or the "Company")?

A. Yes. My direct testimony filed in Unitil base rate proceeding Docket DE 21-030 was also filed by UES in this docketed proceeding in support of UES's proposed Time-of-Use ("TOU") rates for the domestic class and for electric vehicle ("EV") charging. My direct testimony in DE 21-030, as it relates to this proceeding, covered the methodology employed to develop four distinct TOU rates for the following new rates (1) Domestic TOU, (2) Domestic TOU for EV Charging, (3) small general service EV TOU Charging (less than 200 kVA), (4) large general service EV TOU Charging (greater than 200 kVA). Lastly, I discuss the TOU bill analyses prepared by Atrium and the proposal for a demand holiday for the two small and large general service EV TOU Rates.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the following direct testimony submitted by other parties. I will address issues relating to UES's proposed electric vehicle TOU rates and demand holiday as presented in the direct testimonies of New Hampshire Department of Energy ("DOE") witness Sanem Sergici and Clean Energy New Hampshire and Conservation Law Foundation ("CENH/CLF") witness Christopher Villarreal.

Q. Are you sponsoring any schedules in support of your rebuttal testimony?

A. Yes. I am sponsoring Schedule JDT-1 TOU Rate Model.xlsx which is the Excel based TOU rate model utilized in support of the rates and bill impacts presented in this rebuttal testimony.

Q. What conclusions do you draw and further discuss in this rebuttal testimony relating to the direct testimonies of DOE witness Sergici and CENH/CLF witness Villarreal?

A. Below are the primary conclusions and recommendations:

- CENH/CLF and UES both conclude an alternative proposal for demand charges is appropriate, and both look towards a straightforward holiday. The difference is that UES's proposal is limited to four years and the holiday scales back each year; whereas CENH/CLF recommends a 100% holiday that would last up to 10 years or sooner if the total utilization across UES's service territory reaches 30%. UES's proposal demand holiday is appropriately limited in duration, limited in scope, addresses the challenge of demand charges, and ultimately limits the breadth of subsidies that may exist.

- Both the DOE and UES TOU rate derivation methods time differentiate those costs that do relate to system peak demand; generation costs and transmission costs. This is a benefit of an unbundled jurisdiction where different cost occurrences are recovered through different recovery and rate mechanisms.
- The overwhelming vast majority of distribution costs do not vary based on time of day nor the level of energy consumed. Recovering demand-related costs in a time-varying kWh rate creates distortions and results in cross-subsidies.
- Time-varying distribution energy rates are not a sufficient alternative to demand rates for the recovery of demand-related costs and are particularly problematic for large EV stations.
- The New Hampshire Public Utilities Commission ("Commission") should accept UES proposed TOU rates and demand alternative as proposed in UES's direct filing.

II. CLEAN ENERGY NEW HAMPSHIRE AND CONSERVATION LAW FOUNDATION

Q. Please summarize the conclusions drawn by CENH/CLF witness Villarreal.

A. CENH/CLF witness Villarreal recommends the New Hampshire Public Utilities Commission ("Commission") accept UES's Time-of-Use rate design proposal, except for DC Fast Charge ("DCFC") stations. For DCFC stations CENH/CLF witness Villarreal recommends rejecting UES's four-year declining demand holiday proposal and implementing a 100% demand holiday that exists until DCFC utilization factors reach 30% or after ten years; whichever comes first.[1] CENH/CLF witness Villarreal states in support of this position that, "Not collecting demand charges should not have a substantial impact either to the site host or to customers since the low utilization rates of EV charging infrastructure means substantial costs are not being incurred."[2]

Q. How do you respond to the conclusions drawn by CENH/CLF witness Villarreal?

A. First, CENH/CLF agrees with the TOU rates proposed for non-DCFC stations and limits their concern to the demand rate for DCFC stations. CENH/CLF witness Villarreal provides testimony on the challenge of demand charges for the promotion of EV adoption; a challenge recognized in my direct testimony.[3] We both conclude an alternative proposal for demand charges is appropriate, and both look towards a straightforward holiday. The difference is that UES's proposal is limited to four years and the holiday scales back each year; whereas CENH/CLF recommends a 100% holiday that would last up to 10 years or sooner if the total utilization across UES's service territory reaches 30%. Providing a 100% demand rebate for upwards of 10 years can result in several distortions, notably, cost shifting across customers, across classes, and the inability for revenue recovery. CENH/CLF witness Villarreal is simply incorrect in his assertion that not collecting

[1] CENH/CLF witness Villarreal Direct Testimony at page 4.
[2] CENH/CLF witness Villarreal Direct Testimony at page 8.
[3] Taylor Direct Testimony Exhibit JDT-1 at pages 29-31.

demand charges will not result in these distortions when there are low utilization rates because, "…substantial cost are not being incurred."[4] Regardless of a charging facility's actual utilization, distribution equipment that is dedicated to that facility and upstream assets will need to be sized to provide service to that facility based on that station's demand requirements. Costs to UES do not disappear when DCFC stations have low utilization rates. Any rebate program, holiday program, or rate structure that results in one customer not paying for facilities results in either another customer paying for those facilities or the utility not recovering the revenue to cover the costs of those facilities. UES's demand holiday proposal is appropriately limited in duration, limited in scope, addresses the challenge of demand charges, and ultimately limits the breadth of subsidies that may exist. Further, UES's four-year demand holiday program can be re-evaluated to ascertain if changes are beneficial and should be proposed.

Q. Are similar demand holiday programs implemented by other electric utilities for EV charging facilities?

A. Yes. I described in my direct testimony the programs of 1) Southern California Edison (2) PECO Energy Company in Pennsylvania, and (3) PSE&G in New Jersey. While there is a plethora of demand rebate programs in place across the country with varying methods

[4] CENH/CLF witness Villarreal Direct Testimony at page 8.

utilities, commissions, and stakeholders often seek programs that are transparent, limited in scope and duration, and can be reviewed as this new load materializes.

Q. Why is it important to review EV charging programs as load materializes?

A. Any assumptions relating to the level of EV charging facilities, the exact load curves, utilization factors, peak demands, and cost implications are all based on a set of assumptions. For some utilities, these assumptions may only be informed by a handful of stations (or just one station) and rely on costs details from an existing class. Conclusions drawn on consumer behavior, utilization factors, load factors, or results of demand holidays or different rate structures are estimates and illustrative. This is particularly the case for UES; where there is limited system data from DCFC stations; as such the bill impacts and analyses presented in my direct testimony are illustrative; only presenting what may occur based on assumed customer patterns moving forward. Evaluating these customer patterns and utility costs in the future will help better understand the data and pros and cons of different rates to refine the approaches to EV rate design as necessary. This is akin to UES's LED lighting program; where an initial LED program was launched in UES's 2016 rate case and now UES is proposing an expansion of LED offerings as the technology has advanced, UES and its customers better understand the technology, and data is available on customer patterns and usage of this new technology.

III. NEW HAMPSHIRE DEPARTMENT OF ENERGY

Q. Please summarize the conclusions drawn by DOE witness Sanem Sergici.

A. Dr. Sergici states there is insufficient evidence as to why the rate seasons and time periods were used for the TOU rates, and that she prefers analysis showing a correlation between system loads and marginal costs.[5] Dr. Sergici recommends deriving the distribution cost component of the TOU rate by time-differentiating the distribution costs, which she asserts will assign the costs of the system assets to those hours driving the need for those assets.[6] The DOE recommends the Company evaluate whether it will incur additional costs resulting from customers charging from home in addition to the incremental meter costs. Lastly, Dr. Sergici states the demand charge holiday is not warranted since increased transportation electrification is not an official public-policy goal in New Hampshire. The DOE recommends replacing demand rates for these customers with time-varying kWh rates.[7]

Q. How do you respond to the conclusion drawn by Dr. Sergici that further support is required for the time periods proposed by UES?

A. With respect to the choice of time periods, I conducted a review of system load profiles and marginal costs when reviewing the four options under consideration with UES. This

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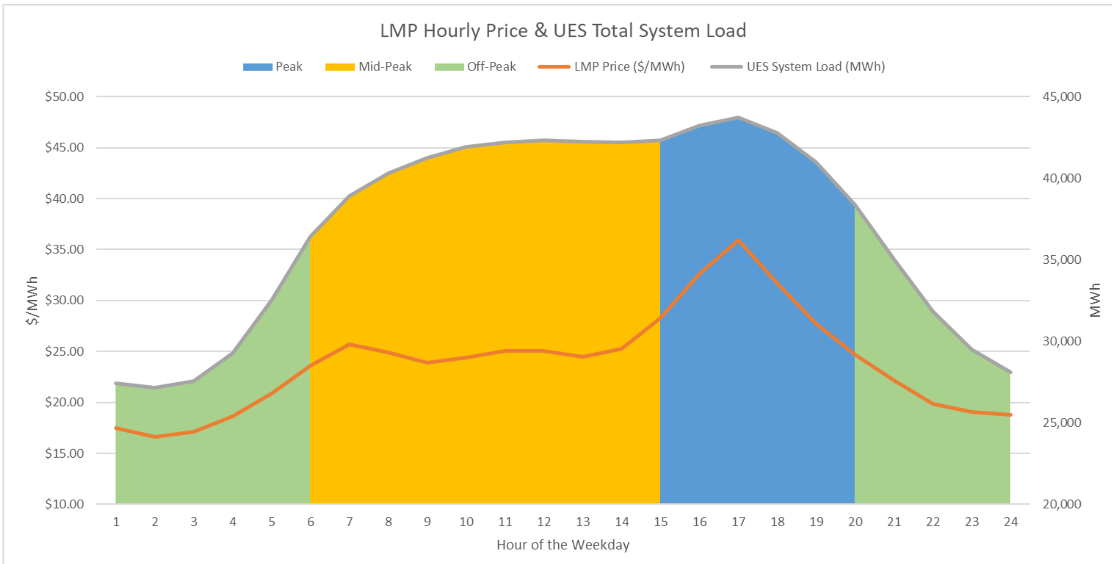
[5] D Sergici Direct Testimony at page 39.
[6] Sergici direct testimony at page 40.
[7] Sergici direct testimony at page 3.

information was provided in the Company's response to CLF & CENH 1-22. As can be seen in the below chart the time periods align well with LMP hourly prices.

Figure 1 – LMP Hourly Prices & UES Total System Load Profile



Further, both Dr. Sergici and I analyzed transmission costs using a similar method and determined that the vast majority of transmission peaks occur during peak hours of 3pm to 8pm; 83% in the summer peak period and 94% in the winter peak period. As such I believe there is sufficient evidence for the time periods proposed by UES.

Q. What support was provided with respect to the chosen seasons of winter and summer?

A. The seasonal periods were chosen to align with the period used by UES to update generation rates, such that there would be limited periods in which TOU rates would be updated for customers across the year. While different seasonal periods could be defined, any benefit from a cost causation perspective would likely be outweighed by decreases in customer understanding and acceptability and administrative simplicity.

Q. Outside of cost causation, are other principles important to consider when evaluating rate design proposals?

A. Yes. While there are various lists of rate design principles cited by regulatory pricing experts, there are always considerations relating to cost causation, price signals, simplicity, customer understanding, and issues relating to bill impacts and gradualism that must be evaluated. These principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. A recent presentation made by Dr. Sergici provides an excellent visual on the trade-offs required when evaluating rate design proposals. [8] See Fig. 2 below. However, the DOE's proposal does not provide a reasonable balance between cost-reflective rates, price signals, and considerations of impacts to customers, particularly when this industry is in its infancy and has significant implications on the environment.

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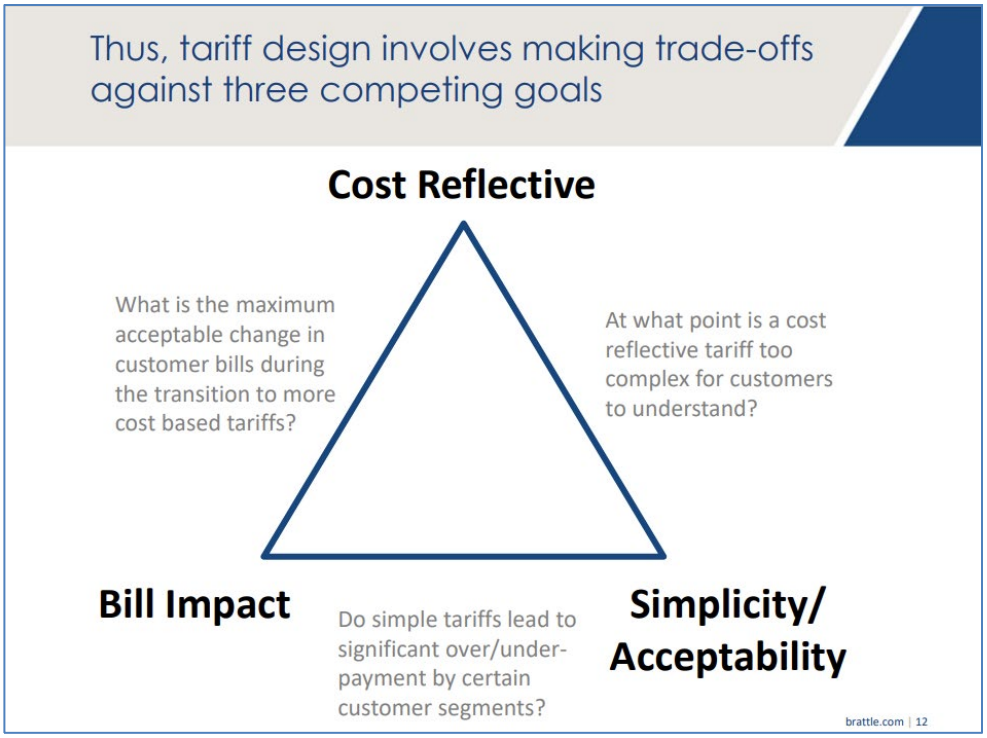
[8] Rate Reform in Evolving Energy Marketplace. Presented by Sanem Sergici, Ph.D. May 30, 2019, available at: https://brattlefiles.blob.core.windows.net/files/16413_rate_reform_in_evolving_energy_marketplace.pdf

Figure 2 – Competing Rate Design Principles



Q. For purposes of developing EV rates, does the DOE recommend time-varying rates of the recovery of generation and transmission costs?

A. Yes. We are generally in agreement with the methods proposed by Dr. Sergici to time differentiate the generation and transmission costs. While Dr. Sergici provides illustrative TOU rates for UES's G1 class without generation costs; as did UES in their direct filing, the DOE does present a modified version of time differentiating generation costs for the other utilities in this proceeding. For these other utilities, and presumably UES's residential and G2 classes, Dr. Sergici assigns 20% of default service costs to the peak period to reflect the fixed costs associated with FCM charges.[9] With regard to time-varying transmission, our methods are nearly identical with Dr. Sergici using the last 10 years of ISO-NE monthly peak hours[10] whereas my direct testimony relied upon the last 20 years.

Q. How do you respond to Dr. Sergici's proposal to recover distribution costs by creating a time-varying kWh rate?

A. This is the major area of disagreement between the DOE witness's evidence in this proceeding and UES's evidence in this proceeding and past proceedings on the nature of distribution costs. The primary points that I will reiterate are as follows:

- The overwhelming vast majority of distribution costs do not vary based on time of day nor the level of energy consumed.
- Both the DOE and UES methods time differentiate those costs that do relate to system peak demand; generation costs and transmission costs. This is a benefit of an unbundled jurisdiction where different cost occurrences are recovered through different recovery and rate mechanisms.
- Recovering demand-related costs in a time-varying kWh rate creates distortions and results in cross-subsidies.

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[9] Sergici direct testimony at page 25.
[10] Sergici direct testimony at page 44.

- Time-varying distribution energy rates are not a sufficient alternative to demand rates for the recovery of demand-related costs.
- While the DOE states there is no public policy goal supporting UES's proposed demand holiday; from this perspective, there should also be no support for subsidies created by inappropriately recovering demand costs over time-varying kWh rates.

Q. Did UES present evidence on which distribution costs vary and over what time those costs vary with respect to the time in which demand is imposed on the system by a customer?

A. Yes. My direct testimony indicated that there is only "a small subset of distribution facilities relating to substations where load diversity (load occurring at different hours) can impact the overall investment requirements of a substation. These costs are incurred based on load estimates, where planning and construction can take years with a useful life of over forty years. These costs are functionalized in the Class Cost of Service Study to the sub-transmission function.".[11] This is shown in the company's ACOSS model within Docket 21-030 (at Bates 1363) and presented below in Table 1:

Table 1 - Sub-Transmission Function Percentage

Class	Sub-Transmission Function Revenue Requirement	Total Revenue Requirement	Percent relating to Sub-Transmission Function
Domestic	$4,264,802	$50,636,343	8%
G2	$1,927,482	$13,612,184	14%
G1	$1,672,924	$5,906,950	28%

[11] Taylor Direct Testimony Exhibit JDT-1 at pages 20.

While Dr. Sergici removed distribution costs recovered through the fixed customer charge, the proposed method time-varied the recovery of all remaining distribution costs. This includes the recovery of meters, services, transformers, and local conductors; equipment sized for a customer's peak demand requirements. If an EV station requires a dedicated transformer; a common requirement of DCFC stations, the transformers are sized for the EV station peak demand; irrespective of when that peak demand occurs. A fleet overnight charging facility still needs UES to provide a transformer and meter, and the costs of this equipment is the same as a similar-sized public charging facility that charges primarily during system peak hours. In short, the recovery of the vast majority of distribution costs should be spread evenly across all usage or recovered on a demand charge basis; not time-varied across all hours of the day.

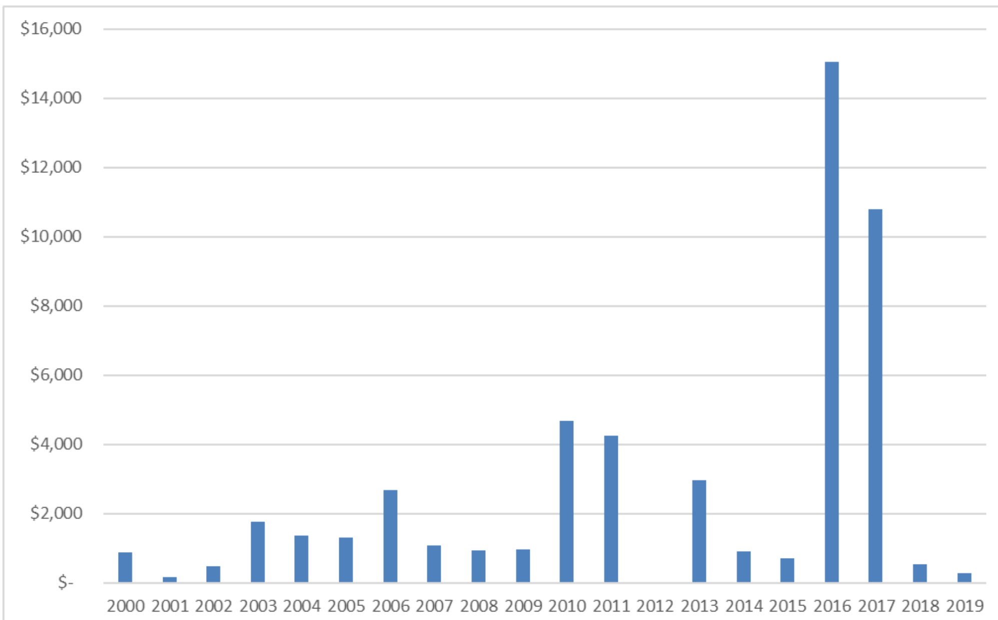
Q. What are the consequences of time-varying the recovery of demand-related distribution costs that do not vary with time of day?

A. Under DOE's proposed method, time-varying the recovery of costs that do not vary with the time of day results in distortions, leading to cross-subsidies or lost revenues. Under the DOE's proposal, a customer that reduces their distribution bill by consuming in the off-peak period does not result in any cost-savings to UES; the same size equipment for any local and dedicated facilities exist. As indicated above in the long run; defined as the time period in which substation equipment is replaced or new substation equipment is needed some costs may vary.

Q. What conclusions can be drawn regarding the time period over which substation costs vary?

A. Table 2 below presents the additions to account 362 Station Equipment over the last 20 years as reported by UES's FERC Form 1 filings.

Table 2 – UES Plant Additions in Account 362 – Station Equipment



As can be seen from this table substation investment represents lumpy investments; large infrequent movements rather than continuous and consistent adjustments over time. The life expectancy of these assets is approximately 49 years, as presented by UES's depreciation report filed in Docket DE 21-030.[12] While these costs may meet the DOE's definition of long-run marginal distribution costs; it is important to understand that this

[12] Docket No. DE 21-030 Exhibit NWA-3 Page 49 of 195 (bates 001704)

definition would equate to 11% of UES's total distribution revenue requirement and would be defined as decades, not months or years.

Q. What costs incurred by UES do vary by the time of day and should be reflected in the time-varying marginal cost of providing electric vehicle charging services

A. The costs that do vary based on time of day solely relate to generation costs and transmission costs. Time-varying these costs for which the DOE proposes and UES proposes is in alignment with the Commission's instructions to utilities, "…Initial 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."[13] One key aspect of the regulatory environment that impacts the evaluation of the merits of different proposals is that UES operates in an unbundled jurisdiction where the rates and recovery for generation, transmission, and distribution costs are no longer linked together. There is separate cost occurrence and cost recovery for generation resources through default service charges or third-party retail marketers, there is separate cost occurrence and recovery of transmission costs, and yet a third process and method to set appropriate distribution rates and cost recovery. The important point, and one that is recognized by Dr. Sergici is that these costs all differ in how they are

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[13] Order No. 26,394 at 4-5 available at: https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-004/ORDERS/20-004_2020-08-18_ORDER_26394.PDF

incurred by UES and how these costs differ across hours of the day and seasons of the year. There is alignment between the DOE and UES that generation and transmission costs are time-varying marginal costs that should be reflected in a TOU rate for EV charging stations. However, time-varying demand-related distribution costs is not a viable alternative to recovering these costs in a demand rate.

Q. What is Dr. Sergici's position on TOU as alternative to demand rates?

A. Dr. Sergici states that time-varying rates are a viable alternative to demand rate.

> "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."[14]

However, it is not apparent why the DOE is proposing to remove demand charges. Testimony has been presented in this proceeding, including my direct, that for EV chargers, demand charges can be initially challenging because EV equipment is likely to be used sporadically to start but still see high power demands, resulting in a final bill heavily tilted towards the demand charges. As such, parties to this proceeding and utilities across the United States have implemented demand charge alternatives including demand holidays, rates that reflect load factors and utilization rates, and flat kWh rates as a replacement of demand rates.

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[14] Sergici direct testimony at page 46.

Q. Does the DOE argue that demand rates should be replaced with time-varying distribution rates to alleviate the impact demand rates can have on EV stations?

A. No. DOE testimony states, "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."[15] From this statement, one can conclude that the DOE does not advocate for the replacement of demand charges with time-varying distribution rates to incentive EV adoption or alleviate the challenges demand rates can place on EV station economics. Thus, the testimony is unclear as to why the DOE proposes to recover demand-related costs that are recovered in a demand rate in a volumetric time-varying kWh rate. UES issued a data request to gain additional insights into this Dr. Sergici stated: "While distribution costs do not vary on an hourly basis, allocating these costs to hours where most of the demand takes place is an effective way to create a price signal to reduce the demand during these hours and avoid/mitigate future investments."[16] As such, it appears Dr. Sergici is in agreement that distribution costs do not vary on an hourly basis and clarifies that the purpose is to send a price signal to avoid/mitigate future investments.

Q. Are there other instances in which Dr. Sergici has opined on the appropriateness of time-varying distribution demand-related costs?

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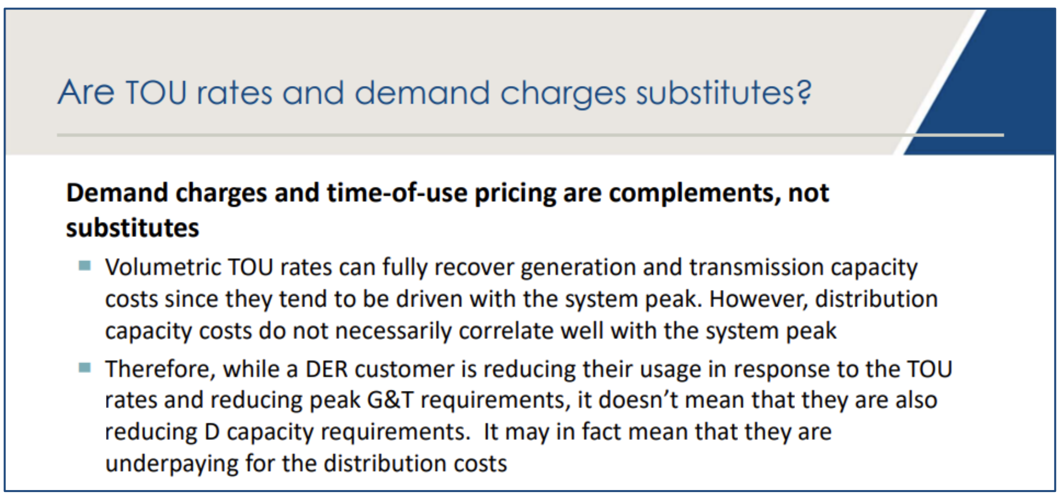
[15] Sergici Direct Testimony at 15
[16] DE 20-170 UES Data Request Set 1 – Response to Unitil 1-2 Witness: Dr. Sanem Sergici

A. Yes. A recent presentation made by Dr. Sergici states that distribution capacity costs do not necessarily correlate well with the system peak and that reduced usage in response to TOU rates may reduce peak generation and transmission requirements but this does not mean there is a reduction in distribution capacity requirements, and, "It may in fact mean that they are underpaying for distribution costs."[17] The relevant page from this presentation is provided in Figure 1 below.

Figure 3 – TOU Rates as Substitutes for Demand Charges



Q. Under what circumstances can the introduction of volumetric TOU rates to recover distribution capacity costs result in a customer underpaying for distribution costs?

A. A primary principle of electricity pricing recommends adherence to the overarching principle of cost-causation, i.e., pricing should be cost-based. When the recovery of

[17] Rate Reform in Evolving Energy Marketplace. Presented by Sanem Sergici, Ph.D. May 30, 2019 available at: https://brattlefiles.blob.core.windows.net/files/16413_rate_reform_in_evolving_energy_marketplace.pdf

distribution capacity costs are based on non-cost causative principles then customers can over or under pay for distribution costs. This is evident when considering costs that are directly incurred to serve a single customer. Every customer premise requires a dedicated meter and dedicated service line; larger customers including DCFC customers may require large, dedicated transformers and dedicated primary lines to upstream substations (depending on location). If revenues from a customer are insufficient to recover the costs of this equipment then the customer is underpaying for distribution costs. Further, in as much as the costs for upstream equipment that serves multiple customers is not reduced as customers' bills are reduced based on the rate structure, those customers are underpaying for distribution costs. Time-varying distribution rates are not cost-causative, do not reflect marginal costing principles, and result in various distortions in prices, consumer behavior, and social outcomes.

Q. What other distortions are created when fixed distribution costs are recovered in time-varying volumetric rates?

A. The primary distortion is that consumers make economic choices that result in lower bills which do not result in lower distribution costs. The private household and business decisions do not align with the implications for society; bills are reduced, however no societal resources are saved, resulting in cost shifting and cross subsidies. Further, the DOE's proposal to recover more fixed costs during peak periods could lead to lower adoption rates as customers are exposed to high peak period charging costs at public EV stations (see bill impacts presented below in testimony).

Q. Can public charging stations simply charge more for peak periods than during off-peak periods?

A. They may or may not be able to do so. EV charging stations that are offered to the public or support daytime charging may have limited ability to control or move use from one time period to another (i.e., their price elasticity can be very low). Dr. Sergici states that, "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."[18] Another response may be that the owners of public chargers choose not to build stations because the economics and/or customer experience are not sufficient to meet their investment thresholds. As stated above the DOE's proposal does not provide a reasonable balance between cost-reflective rates, price signals, and considerations of impacts to customers; particularly when this industry is in its infancy and has significant implications on the environment.

[18] Sergici direct testimony at page 32.

IV. REPLICATING DOE'S PROPOSED METHODOLOGY

Q. Were TOU rates prepared for the three TOU rate offerings using the proposed DOE methodology discussed above in this testimony?

A. Yes. Atrium replicated the methods presented by the Dr. Sergici within the Atrium TOU Excel-based model ("TOU Rate Model") that was used for the development of UES's TOU rate offerings. Dr. Sergici only presented illustrative rates for the TOU-EV-G1: large general service EV TOU Charging (greater than 200 kVA). The model was also updated for the other two proposed TOU rate offerings (1) TOU-EV-D: Domestic TOU for EV Charging and (2) TOU-EV-G2: small general service EV TOU Charging (less than 200 kVA).

Q. Please describe the methods utilized to replicate the proposed DOE methodology within the TOU Rate Model?

A. First, within the generation (Default Service) calculation (for Domestic and G2 only), the generation revenue requirement was separated by percentage into forward capacity market (FCM) costs (20%) and non-FCM costs (80%). Unitil's direct filing did not distinguish between FCM and non-FCM costs. To match the DOE's method non-FCM costs were only allocated to summer peak hours. Next, within the transmission calculation, the transmission revenue requirements by TOU periods are now based on the ten-year (2010-2020) period of ISO-NE monthly peaks rather than the twenty-year period (2000-2020) used in UES's direct filing. Lastly, distribution costs are allocated on a time-varying basis using the "volumetric portion of distribution revenue" (i.e. total annual distribution revenue minus the annual revenue from customer charges), and allocating that annual total to each time period using the steps below.

- The time-varying component of these TOU rates is designed to recover the classes volumetrically recovered distribution revenues at present rates. The total current revenues for each corresponding existing rate class (Domestic, G1, and G2) was first reduced by the costs recovered through the fixed monthly customer charge for that class to derive the costs to be recovered through the time-varying kWh rate.
- The distribution costs for each rate class are calculated each hour within the year by taking the total system load from that hour squared and then calculating the percentage of the total system load squared that that hour represents for the whole year. That hourly percentage is then multiplied by each rate class's volumetric portion of distribution revenue to then derive the monetary portion each hour represents of that total volumetric revenue.
- Those hourly monetary portions are then summed within each TOU period to represent the Distribution Revenue Requirement recovered by TOU rates.
- That TOU period distribution revenue requirement is then divided by each classes' customers energy usage in each TOU period to derive a time-period specific Distribution TOU rate ($/kWh).

As discussed above the DOE's proposed approach for distribution costs is fundamentally different from UES's direct filing as UES' position is that these distribution costs do not vary across hours of the day and are fixed with respect to the demand placed on the system.

Q. What are the resulting rates and peak to off-peak ratio for each of the three EV related TOU rates?

A. The below tables present the results of this modeling for the three EV-related TOU rates.

Table 3 – Replication of DOE's Proposed Method – TOU-EV-D

TOU-EV-D: Domestic TOU for EV Charging

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**TOU Period**	**Default Service TOU Rates ($/kWh)**	**Transmission TOU Rates ($/kWh)**	**Default Service TOU + Transmission TOU Rates ($/kWh)**	**Distribution TOU Rates ($/kWh)**	**Total EV Domestic TOU Rates ($/kWh)**	**Resulting Ratio**
2	**Summer_Peak**	0.26755	0.14525	0.41280	0.04019	0.45299	4.78
3	**Summer_Off-peak**	0.05902	0.00408	0.06310	0.03165	0.09475	1.00
4	**Summer_Mid-peak**	0.07233	0.02496	0.09729	0.04438	0.14167	1.50
5	**Winter_Peak**	0.07163	0.16408	0.23571	0.03603	0.27174	2.88
6	**Winter_Off-peak**	0.05817	0.00577	0.06394	0.03033	0.09427	1.00
7	**Winter_Mid-peak**	0.05972	0.00774	0.06746	0.04190	0.10936	1.16

Table 4 - Replication of DOE's Proposed Method – TOU-EV-G2

TOU-EV-G2: small general service EV TOU Charging (less than 200 kVA)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**TOU Period**	**Default Service TOU Rates ($/kWh)**	**Transmission TOU Rates ($/kWh)**	**Service TOU + Transmission TOU Rates ($/kWh)**	**Distribution TOU Rates ($/kWh)**	**Total EV <200 KVA TOU Rates ($/kWh)**	**Resulting Ratio**
2	**Summer_Peak**	0.26209	0.18050	0.44260	0.05835	0.50095	5.32
3	**Summer_Off-peak**	0.04882	0.00408	0.05290	0.04131	0.09422	1.00
4	**Summer_Mid-peak**	0.06232	0.02024	0.08256	0.03991	0.12247	1.30
5	**Winter_Peak**	0.06689	0.18019	0.24708	0.04607	0.29315	2.98
6	**Winter_Off-peak**	0.05434	0.00591	0.06024	0.03813	0.09837	1.00
7	**Winter_Mid-peak**	0.05600	0.00686	0.06286	0.03694	0.09980	1.01

Table 5 - Replication of DOE's Proposed Method – TOU-EV-G1

TOU-EV-G1: large general service EV TOU Charging (greater than 200 kVA)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**TOU Period**	**Default Service TOU Rates ($/kWh)**	**Transmission TOU Rates ($/kWh)**	**Default Service TOU + Transmission TOU Rates ($/kWh)**	**Distribution TOU Rates ($/kWh)**	**Total EV >200 KVA TOU Rates ($/kWh)**	**Resulting Ratio**
2	**Summer_Peak**	-	0.17751	0.17751	0.03229	0.20980	8.17
3	**Summer_Off-peak**	-	0.00408	0.00408	0.02159	0.02567	1.00
4	**Summer_Mid-peak**	-	0.02097	0.02097	0.02348	0.04446	1.73
5	**Winter_Peak**	-	0.18781	0.18781	0.02706	0.21486	7.89
6	**Winter_Off-peak**	-	0.00589	0.00589	0.02133	0.02722	1.00
7	**Winter_Mid-peak**	-	0.00707	0.00707	0.02234	0.02941	1.08

Q. What conclusions or recommendations can be drawn from these resulting time-varying rates and associated peak to off-peak ratios?

A. One key element to the rationale for the DOE's proposal is, "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."[19] While there is significant disagreement as to the cost-reflective price signal created when time-varying distribution costs, it can be noted that during peak periods, under the DOE's approach, the vast majority of the time-varying kWh rate consists of default service and transmission costs. For instance, for the Domestic EV class, 91% of the summer peak rate relates to default service and transmission costs. Another way to view this is the time-varying default service and transmission costs results in a rate of $0.41459 (Table 3 line 2 column D) during the summer peak hours; compared to the current distribution kWh rate of $0.03558. The DOE

[19] Sergici direct testimony at page 46.

has presented no evidence that it is necessary to increase the TOU peak rate by 9%, by time-varying demand-related distribution costs to incentivize customers to shift their load. Similar conclusions can be drawn for the other two rates by reviewing data in Table 4 and Table 5.

Q. What are the implications of the DOE's TOU rates for EV charging station bills?

A. Atrium conducted a bill impact analysis using the rates resulting from the replication of DOE's methods, as described above. For the G1 customer class, illustrative bill impacts with load factors of 5% and 10% for an average summer month were constructed to show the differences between Unitil's current rates, Unitil's EV TOU proposal, and DOE's method for calculating TOU EV rates. A billed demand was assumed at 300 kVA, and non-holiday weekday monthly energy was calculated assuming a 95% power factor for a DCFC station load profile and a 5% or 10% load factor. Energy charges were calculated for each hour of a 24-hour period the hourly load profile and each subsequent rate design method. Demand charges were then calculated given respective demand rates ($7.60/kVA for current and Unitil's EV TOU proposal, and zero for DOE's method) and demand cost reductions (75% reduction for Unitil's EV TOU proposal). The total monthly charges for each rate design method (exclusive of generation costs), as well as the differences from Current Rates, can be seen in Table 6 and Table 7 below.

Table 6 – Bill Impact – 5% Load Factor Assumption

G1 EV w/ LF 5%	Current Rate	Unitil EV TOU Proposal (75% demand reduction)	DOE Method (100% Energy)
Billed Demand (kVA)	300	300	300
Monthly Energy (kWh)	34,200	34,200	34,200
Load Factor	5%	5%	5%
Customer Charge ($/month)	$ 86.49	$86.49	$86.49
Energy Charges	$1,242.23	$2,506.72	$3,663.31
Demand Charges	$2,280.00	$570.00	$0.00
TOTAL Monthly Charge	**$3,608.72**	**$3,163.21**	**$3,749.80**
Difference from Current Rates		($445.52)	$141.08

Table 7 - Bill Impact – 10% Load Factor Assumption

G1 EV w/ LF 10%	Current Rate	Unitil EV TOU Proposal (75% demand reduction)	DOE Method (100% Energy)
Billed Demand (kVA)	300	300	300
Monthly Energy (kWh)	102,600	102,600	102,600
Load Factor	10%	10%	10%
Customer Charge ($/month)	$86.49	$86.49	$86.49
Energy Charges	$3,726.70	$5,188.91	$7,583.06
Demand Charges	$2,280.00	$570.00	$0.00
TOTAL Monthly Charge	**$6,093.19**	**$5,845.40**	**$7,669.55**
Difference from Current Rates		($247.79)	$1,576.36

Q. What do these bill impacts demonstrate with respect to the TOU rate proposals and the demand charge holiday proposal?

A. While the demand component of EV stations bills can be a large portion of total costs and prohibitive in the development of these stations, so too can time-varying energy costs. The proposed TOU rate design presented by Dr. Sergici results in higher bills for EV station owners and are significantly higher when load factors increase; as revenues recovered through demand charges are over collected through distribution kWh charges. The TOU rates proposed by the Company and the demand charge holiday are well-balanced where time varying rates are in place for generation and transmission costs with a recognition that stations demand charges can be prohibitive. UES's proposal is the proper balance of cost-reflective rates and associated price signals, bill impacts, and simplicity and acceptance.

Q. Does this conclude your direct testimony?

Yes, it does.