UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

JOHN D. TAYLOR

MANAGING PARTNER
ATRIUM ECONOMICS, LLC

New Hampshire Public Utilities Commission

Docket No. DE 21-030

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Schedules and Attachments

Direct 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. Please describe your professional background and education.

A. A copy of my resume is provided as Attachment A. I have been employed as a utility consultant since 2006 providing rate, regulatory, strategic and other consulting services. Prior to joining Atrium I was employed at Black & Veatch Management Consulting and Concentric Energy Advisors. As a utility pricing and policy expert, I am involved in a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. Part of my role within these projects is to conduct various analyses which take into account both accounting and financial considerations and the particular operational configuration of a company's assets. I began my education studying electrical and mechanical engineering and worked for an industrial inspection company, which provided me with hands-on experience with electric utility assets and equipment. I have a B. A. degree in environmental economics from University of North Carolina at Asheville and masters in economics from American University.

Q. **Have you previously testified before the New Hampshire Public Utilities Commission ("the Commission")?**

A. No.

Q. **Please provide a list of state and Canadian jurisdictions in which you have testified.**

A. I have presented expert testimony in state public utility regulatory proceedings in Indiana, Maine, Minnesota, Illinois, Delaware, Pennsylvania, Washington, and West Virginia. In Canada I have provided expert reports before the Ontario Energy Board, the Alberta Energy and Utilities Board, and the British Columbia Utilities Commission. I have also testified before the Federal Energy Regulatory Commission ("FERC") on electric transmission matters. My testimony and expert reports relate to various utility regulatory issues such as cost of service, rate design, affiliate transactions, line extension polices, revenue requirements, and modernization programs such as electric vehicle programs and battery storage projects.

Q. **What is the purpose of your testimony in this proceeding?**

A. Unitil Energy Systems Inc. ("UES" or the "Company") retained Atrium to conduct the allocated class cost of service study ("ACOSS"), the marginal class cost of service study ("MCOSS"), the revenue apportionment and revenue targets by class, the rate design for existing rate classes, Light Emitting Diode ("LED") Lighting rates, and Time-of-Use ("TOU") rates for the domestic class and for electric vehicle ("EV") charging. I am supporting the Company's rate design proposals including new LED Lighting rates, the Domestic TOU rate and TOU rates for EV charging. My colleague Ron Amen is supporting the ACOSS, MCOSS, and revenue apportionment and revenue targets by class in separate testimony.

Q. **Please summarize the content of your testimony and associated schedules.**

A. First, I will discuss various principles of rate design and the rate design proposals for the existing UES rates and for the new LED Lighting rates. I then present 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.

The testimony is supported with the following schedules.

- Schedule JDT-1 – Rate Design
- Schedule JDT-2 – LED Lighting Rate Analysis
- Schedule JDT-3 – Bill Impacts for Current Rates

II. PRINCIPLES OF SOUND RATE DESIGN

Q. **Please identify the principles of rate design utilized in development of the Company's rate design proposals.**

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service and Cost Causation;

(2) Efficiency;

(3) Value of Service;

(4) Stability/Gradualism;

(5) Non-Discrimination;

(6) Administrative Simplicity; and

(7) Balanced Budget.

Q. **These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by Prof. James Bonbright in his widely-referenced treatise on utility ratemaking, Principles of Public Utility Rates.[1] Can the objectives inherent in these principles compete with each other at times?**

A. Yes, these principles can compete with each other and this tension requires further judgment to strike the right balance between the principles. For example, there is tension between cost of service and value of service principles; efficiency and simplicity; simplicity and non-discrimination; and value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process. Detailed evaluation of rate design recommendations must recognize and effectively address the potential and actual tension between these principles.

Q. **How are these principles translated into the design of rates?**

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[1] Bonbright, J. C., Danielson, A. L., & Kamerschen, D. R. (1988). *Principles of Public Utility Rates, Second Edition*. Public Utility Reports, Inc. Page 111-113.

A. The overall rate design process includes the determination of rate structures within rate classes, which entails finding a reasonable balance between the above-described utility rate design principles. Economic, regulatory, historical, and social factors must also be considered in the process. In other words, the rate design process must necessarily include the exercise of judgment, as both quantitative and qualitative information must be evaluated before reaching a final rate design determination.

III. RATE DESIGN PROPOSALS – UPDATES TO CURRENT RATES

Q. **Please summarize the rate design changes UES has proposed in this rate proceeding.**

A. The proposed rate design has capped the customer charge increase at the overall percentage increase for each class. The remaining increase for rates with kWh charges has been included in a flat energy charge. For rates with a demand charge, the remaining increase after the customer charge increase has been added to the demand charge. This emphasis on fixed charges is consistent with the nature of the costs being recovered. UES has proposed the following rate design changes to its current tariff schedules:

(1) Residential – Increase in the Monthly Customer Charge from $16.22 to $21.07, with the remaining proposed increase to be recovered in the Volumetric Charge.

(2) General Service-G1 – Increase in the Monthly Customer Charge from $162.18 to $178.93 for secondary and $86.49 to $95.42 for primary customers, with the remaining proposed increase to be recovered in the Demand Charge.

(3) General Service-G2 Non-Demand - Increase in the Monthly Customer Charge from

$18.38 to $20.28 for non-water heater or space heating and $9.73 to $10.73 for water heating/space heating customers, with the remaining proposed increase to be recovered in the Volumetric Charge.

(4) General Service-G2 Demand – Increase in the Monthly Customer Charge from $29.19 to $32.20, with the remaining proposed increase to be recovered in the Demand Charge.

(5) Lighting – Update the existing fixture rates and introduce new LED fixture rates, as described in more detail below.

Q. **Is UES proposing any new rates?**

A. Yes. The Company is proposing new rates for LED fixtures under its existing Outdoor Lighting rate schedule and LED rate schedule. In addition, UES is proposing four distinct TOU rates:

(1) TOU-D: Domestic TOU rate
(2) TOU-EV-D: Domestic TOU for EV Charging
(3) TOU-EV-G2: small general service EV TOU Charging (less than 200 kVA)
(4) TOU-EV-G1: large general service EV TOU Charging (greater than 200 kVA).

Q. **Overall, what is your conclusion on UES's proposed rate designs as filed in this proceeding?**

A. The Company's proposed rates recognize that while a primary goal of rate design is to seek economic efficiency, consideration should be given to the need for gradualism. The Company is undertaking an increase in rates for all rate classes by increasing all rate components over the current rates. Instead of recovering the full revenue increase entirely through volumetric charges, the Company has proposed a partial increase in the customer charges. This brings the fixed charge closer to the marginal customer cost.

Q. **Please explain the proposed changes to the Company's domestic rate schedule.**

The domestic rate schedule as proposed consists of a $21.07 per month customer charge a result of capping the customer charge increase at the overall percentage increase for the domestic rate class. The remaining increase for rates with kWh charges has been included in a flat energy charge.

Q. **Please explain the rate proposal for the G2 non-demand schedule.**

A. The proposed customer charges for the G2 non-demand billed customers are $20.28 per month and $10.73 per month for water heating/space heating. The remaining proposed revenues are recovered through the volumetric charges.

Q. **Please explain the proposed changes to the Company's G2 and G1 demand rates.**

A. Both the customer charges and demand charges were increased to produce the revenue requirements for each rate schedule. There are no proposed changes to the transformer ownership credit of $0.50 per kW.

Q. **Have you prepared a detailed comparison of the Company's present and proposed rates and resulting revenues by rate class?**

A. Yes. Schedule JDT-1 presents a detailed comparison of present and proposed revenues for each of UES's rate classes.

Q. **Have you prepared bill impact analyses?**

A. Yes, Schedule JDT-3 provides monthly bill impact analyses by class for an appropriate range of monthly usage levels. These analyses demonstrate the combined impact of the rate design changes that are being proposed in this proceeding.

IV. PROPOSAL FOR UPDATED LED LIGHTING RATES

Q. **What are the current Outdoor Lighting rates offered by UES?**

A. The Company currently offers Outdoor Lighting under two rates, Outdoor Lighting Service Schedule OL, which is available to all customers, and Light Emitting Diode Outdoor Lighting Service Schedule LED, which is available to customers who have entered into a Service Agreement and paid the installed costs of the fixtures and brackets.

Q. **Please elaborate on the differences between Schedule OL and Schedule LED.**

A. There are two principal differences between Schedule OL and Schedule LED. First, for customers served under Schedule OL, the Company purchases, installs, owns, and maintains the lighting fixtures, whereas customers served under Schedule LED purchase and pay for the installation of the lighting fixtures, and maintenance is provided by the Company on a charge-per-visit basis. The ownership of the lighting fixtures installed under Schedule LED is transferred to the Company. Service under Schedule LED requires a service agreement. The second principal difference between Schedule OL and Schedule LED is the type of lighting fixtures available. Under Schedule OL, sodium vapor and metal halide luminaires are available, whereas under Schedule LED light emitting diode luminaires are available.

Q. **What has been the market's response to the Schedule LED rate offerings approved in UES's last base rate proceeding?**

A. Of the 9,029 fixtures on UES's distribution grid, 1,736 lighting fixtures were replaced as of December 2020 through the current tariff offering and special contracts with large municipal lighting customers. This represents a conversion of approximately 19% of the lighting fixtures. Current LED technology is sufficiently established to enable the Company to offer LED lighting fixtures under Schedule OL to those customers who may not have an interest or the ability to purchase their own lighting fixtures but would want to choose the type of lighting fixture they prefer. Additionally, there is an operational benefit for the Company to determine what outdoor lighting technology is most appropriate on a going forward basis.

Q. **What new LED outdoor lighting rates are being proposed?**

A. The Company is proposing the following changes to its Outdoor Lighting service: Starting January 1, 2023, it will no longer offer sodium vapor and metal halide luminaires. From that date on, as these legacy fixtures need replacement, they will be replaced with LED fixtures, and there will be no special charges to the customer for this replacement. If, however, a customer requests a conversion of a legacy fixture, or multiple fixtures, to LED service in advance of its actual need, requirement for replacement, or Company planned servicing, the Company may require the customer to pay all or a portion of the costs of the conversions, including labor, material, traffic control, and overheads. Conversions are contingent upon the availability of Company personnel and/or other resources necessary to perform the conversion. Customers wanting to purchase their own LED fixtures will still have that option under Schedule LED if they meet the requirements of Schedule LED.

Q. **What will be the new LED Luminaire charges offered?**

A. The new LED Luminaire charges are specified in Schedule JDT-1. To accommodate the evolution of LED lighting fixtures, the Company proposes to offer luminaire charges encompassing a range of fixtures as opposed to the exact specifications of each individual fixture available on the market today, as provided in the proposed tariff. In addition, lighting fixtures other than that specified in the tariff will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the customer.

Q. **How were the Schedule LED Lighting Rates developed?**

A. Consistent with the current tariff for Schedule LED, any customer wishing to convert to LED will be converted based on the following:

1. Customer will pay the cost of the new LED equipment,
2. Customer will pay the actual cost of installation, and
3. Customer will pay the depreciated book value of the current lighting equipment being removed and cost of removal.

The Company will charge separately for any maintenance cost relating to the new LED fixture on a per-visit basis. In order to determine the fully-allocated rate for the Schedule LED rates, the total cost of service for the Outdoor Lighting class was adjusted down by the amounts related to the net plant associated with the current lighting equipment in service and the depreciation expense and maintenance costs associated with the current lighting equipment. With those costs removed from the embedded cost revenue requirements, unit rates were developed for the LED lighting class which reflects the payments being made for embedded costs by those customers wishing to convert their lighting to LED. These unit rates were then scaled up to the revenue requirement apportioned to the Outdoor Lighting Class to develop the Schedule LED rates as shown on Schedule JDT-3.

Q. **How were the Schedule OL Lighting Rates developed?**

A. The Schedule OL lighting rates were developed using an equivalent fixture procedure. The current tariff lighting fixtures were aligned with an equivalent LED fixture based on lumens output. Then the revenue requirement for the OL lighting rates was calculated using the existing tariff fixtures and rates. This revenue requirement by existing tariff was then aligned with the equivalent LED fixture types. The proposed Schedule OL lighting rates were calculated by dividing the total revenue requirement by LED fixture type by the existing fixtures aligned with the equivalent LED fixture type. This results in the recommended rates for the existing tariff fixtures and the corresponding equivalent LED fixtures being equal for Company paid fixtures. For customer-paid LED fixtures under Schedule OL, the Company paid fixture rates were reduced by an amount equal to the monthly portion of the annual carrying charge of the LED fixtures.

Q. **Does the Company envision that updates will be needed to the rate design during the course of this proceeding?**

A. Yes, the number of conversions to LED lighting is increasing since the test year. The Company anticipates the need to update its rate design to ensure that its revenue requirement will be met using an up-to-date luminaire count.

Q. **What options are available for large municipal lighting customers to utilize lighting control systems?**

A. UES is able to support the development of LED lighting rates for customers with multiple LED lights through their special contract provisions. The special contracts can be developed to contain a provision which would allow the customer to select the output and hours of operation on an annual basis with these updates being reflected in the charges during the next year.

Q. **Have you prepared a schedule supporting calculation of proposed lighting rates?**

A. Yes, proposed rate design calculations are provided in my Schedule JDT-2.

Q. **Has the Company made tariff changes to reflect its proposal as I describe above?**

A. Yes, Schedule OL and Schedule LED have been revised consistent with this proposal and are included in the Company's filing.

V. TIME OF USE RATES

Q. **Please summarize the purpose of this portion of your testimony.**

A. Atrium has developed TOU Rates for UES's Domestic rate class and for EV Charging. This section of my testimony provides a description of the TOU analytics utilized to develop the TOU rates and the resulting bill impacts resulting from the proposed TOU rates.

Q. **Have guiding principles and approaches been provided by the Commission with regard to developing EV TOU Rates?**

A. Yes. There are some guiding principles outlined by the Commission in Order No. 26,394 on August 18, 2020 within Docket IR 20-004. The first excerpt below summarizes Staff's recommendations to the Commission. The second excerpt articulates the Commission's guidance.

> "Staff recommended the Commission issue guidance that any separately-metered residential electric vehicle charging rate should: (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."[2]

> "The guidelines proposed by the Commission Staff regarding a consistent framework for separately-metered residential electric vehicle charging rate

[2] State of New Hampshire Public Utilities Commission, Order No. 26,394 Docket IR 20-004 dated August 18, 2020 page 15.

> designs are appropriate, subject to three clarifications. First, we agree with the City of Lebanon that the five-hour peak duration is more appropriate than the four-hour peak duration. Second, the 3:1 peak to off-peak ratio should represent an average ratio during a given year, not during any one season. Third, we note that these guidelines serve as a useful starting point and are generally consistent with the rate designed and approved for the purposes of Liberty's Battery storage pilot, and later adopted for Liberty's separately-metered EV TOU Rate. Liberty Utilities (Granite State Electric) Corp., Order No. 26,376 at 9. (June 30, 2020)."[3]

Q. **What were the general principles and approaches utilized to develop UES's TOU Rates?**

A. In general, we aimed to follow the Commission's guidance as described above. The goal was to address all issues highlighted through our analyses and this testimony to ensure a full understanding of the options in the context of the principles and approaches outlined by the Commission. A primary principle of our approach is to develop cost causative rate differentials for costs that vary throughout the day as the primary quantitative inputs to the TOU rates. When cost causation is not adhered to we are explicit in the application of non-cost causative principles as qualitative inputs to the TOU rates. In short, the aim is to comply with the Commission's order as detailed in the following excerpt.

[3] State of New Hampshire Public Utilities Commission, Order No. 26,394 Docket IR 20-004 dated August 18, 2020 page 16.

"We encourage the utilities to consider applying the marginal cost methodology we approved in DE 17-189, as explained in the TOU Technical Statement marked as Exhibit 20 in that docket. Any utility that chooses not to utilize that methodology for its initial proposal should include an explanation in testimony as to why the proposed alternative methodology is appropriate."[4]

Q. **What are the primary rate components that make up the cost of electricity for UES's customers?**

A. There are three main rate components: (1) generation, which is provided through default energy service or through competitive energy suppliers; (2) transmission costs that are separately charged to all customers and adjusted annually; and (3) distribution costs that are set in base rate proceedings. For purposes of developing time-differentiated rates, the costs for default supply were utilized for the generation component. In order to develop a TOU rate, all three components must be considered, and an analysis conducted on how the costs of each component vary across time; either by hour or across blocks of time. As such, a methodology must be developed to ensure the costs assigned to each TOU period are appropriate.

Q. **What method was utilized in determining how the cost of the generation component varies across time?**

A. The method employed by Atrium in our analytics is similar in approach to Liberty's methods as described in the TOU Technical Statement marked as Exhibit 20 in DE 17-

[4] State of New Hampshire Public Utilities Commission, Order No. 26,394 Docket IR 20-004 dated August 18, 2020 page 5.

189 (referred to as the "Liberty Storage Method"). It is also similar to other methods Atrium has employed for TOU rate modeling in other jurisdictions with Independent System Operators and no generation ownership. The general approach is to first differentiate Default Service seasonal energy purchases by time period (i.e. Summer on-peak, Winter off-peak, etc.), using seasonal load profile contributions to each time period as a guide. Second, the marginal cost per hour is calculated by multiplying the average Independent System Operator – New England ("ISO-NE") market clearing Locational Marginal Price ("LMP") for New Hampshire across each hour from multiple years and the class's hourly load over a test year. Third, a time-differentiated marginal rate is calculated by dividing the marginal cost by the Default Service energy purchases for each time period and season. The share for each time period of those time-differentiated marginal rates for each season is then computed to calculate time-of-use ratios. These ratios are then applied to the seasonal Default Service power supply total costs for each time period, resulting in time-differentiated Default Service rates. In addition to time-differentiating the total Default Service power supply costs, the costs associated with line losses and the Renewable Portfolio Standard ("RPS") charge were allocated equally to all time periods such that the rate associated with these costs did not vary across time periods.

Q. **What method was utilized in determining how the cost of the transmission component varies across time?**

A. The method employed by Atrium is similar to the approach utilized within the Liberty Storage Method. The general approach is to time-differentiate UES's annual system transmission cost by season and time period, then divide those costs by time-differentiated system transmission deliveries (kWh). ISO-NE and transmission utility tariffs allocate FERC jurisdictional transmission revenue requirements (Regional Network Service or "RNS" and Local Network Service or "LNS") based on each distribution utility's share of the monthly coincident hour of peak load for the whole system (for RNS) and of their transmission provider's LNS peak. UES's transmission provider (at the LNS connection/wholesale meter point) is Eversource, which uses the system monthly peak for its LNS as well as RNS. The probability of the monthly coincident peak hour occurring during any particular TOU period is assumed to correspond to the historic experience over the most recent ten years split into winter and summer seasons for 60 data points in each season. Those hourly probabilities based on historic experience were then consolidated into the TOU periods. The current volumetric transmission rate (from DE 20-098) was then divided into two components: current transmission charges, allocated as described above, and various reconciliations, mostly prior period under-recovery, which were allocated on a flat volumetric basis to all TOU periods. Current transmission charges were apportioned to the TOU periods based on the assumed probability of monthly coincident peak hours, the cost causation, occurring during each period.

Q. **What analysis was conducted to time-differentiated costs associated with the distribution component?**

A. As discussed earlier in this testimony and previously by UES in past proceedings, 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 the developing a time-of-use rate that is purely cost causative.

Q. **How was the distribution component of costs time-differentiated in the Liberty Storage Method?**

A. The settling parties in DE 17-189 employed a "cost duration method" described as follows:

> "The "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)."[5]

The premise of this method is that there are a small number of peak hours during which system assets necessary to meet demand are used infrequently and thus it is appropriate to assign a significant share of cost for these assets to those peak hours. The approach then assigns another portion of system costs equally to all 8,760 hours of the year. The basic method is akin to a probability-of-dispatch allocation that is sometimes utilized for generating assets and is an attempt to allocate generation capital and fuel across all 8,760

[5] DE 17-189, "Technical Statement Regarding Time-of-Use (TOU) Model" Hearing Exhibit #20 in DE 17-189 (Nov. 29, 2018).

hours and aligning those costs with load duration curves for each rate class across the 8,760 hours.

Q. **Did the TOU modeling conducted by Atrium rely on this method for time differentiating the distribution component?**

A. No. Allocating distribution costs across 8,760 hours based on the peak loads placed on the system during each of those hours does not align with cost causation. Electric utilities invest in distribution infrastructure for two primary purposes (1) to meet the demand requirements of their customers and (2) to extend service to customers and provide dedicated customer related infrastructure like meters and services. Investment relating to extending service to customers (i.e., the customer component of the distribution system discussed by Mr. Amen in separate testimony) in no way varies with peak demand or hour of the day. The level of infrastructure required to meet the demand requirements of customers does vary based on the level of demand but does not vary based on when during the day that demand occurs. 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. As such, we did not rely on the Liberty Storage Method to time-differentiate the distribution component.

Q. **Would the shifting of peak demand to off-peak periods reduce some distribution costs over time?**

A. This is possible, but likely for 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 and for the Domestic rate class represent 7.4 percent of the total revenue requirement. Load shifting may have some impact on the level of investment but it would be marginal given these costs only represent a small portion of total system costs, would not impact the utilities costs structure in the next forty years, and would be extremely difficult to estimate.

Q. **What method was utilized to time-differentiate the distribution component of costs?**

A. As further explained below the TOU model utilized is able to separately analyze and develop rates for the generation, transmission, and distribution components. For the "whole house" TOU Domestic Rate the distribution component was not time-differentiated as the costs of providing distribution service does not vary with the hour of the day. To develop the Domestic EV TOU Rate, the distribution component was time-varied in order to produce a TOU rate for all three components with a 3 to 1 on-peak to off-peak ratio as desired by the Commission and expressed in Order 26,394. In short, the allocation of the generation and transmission components across time periods was cost causative but the differentiation of the distribution component for purposes of developing the Domestic TOU EV Rate was to obtain the targeted 3 to 1 on-peak to off-peak ratio as was requested by the Commission.

Q. **Why is UES supporting EV TOU Rates that are not fully cost causative?**

A. As outlined in the testimony of Company witnesses Carroll, Simpson, and Valianti, UES is proposing an EV initiative which contains multiple elements of support for the electrification of the transportation industry. Mass market adoption of EVs will be reliant upon charging networks, and those networks will need to be accessible, convenient, and affordable, particularly at home.

Q. **Please describe the Excel-based model that Atrium utilized to develop the TOU rates.**

A. The Excel-based model allows for the development of time-differentiated rates for each of the three rate components across various time periods. The model provides the ability to define the peak periods across differing time periods and run the analysis for these different time periods. It collates information relating to the LMP clearing price and the transmission hourly peak demands and applies the procedures detailed above. This can be done across various periods of time to develop different options or scenarios. The model also allows for modeling multiple rate classes simultaneously so as time periods are redefined the calculations are updated for all rate classes being reviewed.

Q. **What time period options were analyzed by Atrium when running the TOU rates model?**

A. Atrium utilized the TOU Rates model to review the following four options:

Option 1: Summer (May-Oct); Winter (Nov-Apr)

(a) On-Peak: Non-holiday weekdays, 6am to 8pm

(b) Off-Peak: Non-holiday weekdays, 8pm to 6am. All holidays and weekends.

Option 2: Summer (May-Oct); Winter (Nov-Apr)

(a) On-Peak: Non-holiday weekdays, 6am to 8pm

(b) Off-Peak: Non-holiday weekdays, midnight to 6am. All holidays and weekends.

(c) Mid-Peak: Non-holiday weekdays, 8pm to midnight.

Option 3: Summer (May-Oct); Winter (Nov-Apr)

(a) Super-Peak: Non-holiday weekdays, 3pm to 8pm

(b) On-Peak: Non-holiday weekdays, 6am to 3pm

(c) Off-Peak: Non-holiday weekdays, midnight to 6am. All holidays and weekends.

(d) Mid-Peak: Non-holiday weekdays, 8pm to midnight.

Option 4: Summer (May-Oct); Winter (Nov-Apr)

(a) On-Peak: Non-holiday weekdays, 3pm to 8pm

(b) Off-Peak: Non-holiday weekdays, 8pm to 6am. All holidays and weekends.

(c) Mid-Peak: Non-holiday weekdays, 6am to 3pm

Q. **When developing the domestic TOU Rate, what were the resulting rates for the time periods analyzed under each of the options listed above?**

A. The results can be viewed within Table 1 below for the domestic whole facility TOU rate. As described above only the generation and transmission components were time-differentiated for this rate and the distribution component of the rate is the same during all time periods. Table 2 – Domestic EV TOU Rate provides the results with a time differentiated distribution component. Given the desire to further incentivize the adoption of electric vehicles, and in alignment with Commission guidance discussed above, the Domestic EV TOU Rate (Table 2) is varying the remaining portion of the distribution costs in a manner that results in a total TOU rate with a ratio of 3 to 1 on-peak to off-peak.

Table 1 – Domestic Whole Facility TOU Rate

	Schedule D - Domestic (whole class) TOU Rate									
		Option 1		Option 2		Option 3		Option 4	
	Time Periods	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio
Summer: May-Oct	Summer_Super-peak	-	-	-	-	$ 0.2478	2.18	-	-
	Summer_Peak	$ 0.1991	1.76	$ 0.1991	1.76	$ 0.1631	1.44	$ 0.2478	2.19
	Summer_Off-peak	$ 0.1133	1.00	$ 0.1134	1.00	$ 0.1134	1.00	$ 0.1133	1.00
	Summer_Mid-peak	-	-	$ 0.1130	1.00	$ 0.1130	1.00	$ 0.1631	1.44
Winter: Nov-Apr	Winter_Super-peak	-	-	-	-	$ 0.3201	2.35	-	-
	Winter_Peak	$ 0.2210	1.59	$ 0.2210	1.63	$ 0.1507	1.11	$ 0.3201	2.31
	Winter_Off-peak	$ 0.1386	1.00	$ 0.1360	1.00	$ 0.1360	1.00	$ 0.1386	1.00
	Winter_Mid-peak	-	-	$ 0.1482	1.09	$ 0.1482	1.09	$ 0.1507	1.09

Table 2 – Domestic EV TOU Rate

	Schedule D - Domestic EV TOU Rate									
		Option 1		Option 2		Option 3		Option 4	
		Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio
Summer: May-Oct	Summer_Super-peak	$ -	-	$ -	-	$ 0.2762	3.00	$ -	-
	Summer_Peak	$ 0.2385	3.00	$ 0.2351	3.00	$ 0.1769	1.92	$ 0.2896	3.00
	Summer_Off-peak	$ 0.0795	1.00	$ 0.0783	1.00	$ 0.0921	1.00	$ 0.0965	1.00
	Summer_Mid-peak	$ -	-	$ 0.0979	1.25	$ 0.1117	1.21	$ 0.1663	1.72
Winter: Nov-Apr	Winter_Super-peak	$ -	-	$ -	-	$ 0.3485	3.00	$ -	-
	Winter_Peak	$ 0.2789	3.00	$ 0.2728	3.00	$ 0.1645	1.42	$ 0.3661	3.00
	Winter_Off-peak	$ 0.0930	1.00	$ 0.0909	1.00	$ 0.1162	1.00	$ 0.1220	1.00
	Winter_Mid-peak	$ -	-	$ 0.1232	1.35	$ 0.1484	1.28	$ 0.1541	1.26

As can be seen by comparing Table 1 with Table 2 the on-peak to off-peak ratio for the "whole house" TOU rate varies from 1.59 to 1 through 2.35 to 1 (depending on option and which season); whereas the on-peak to off-peak ratio for the Domestic TOU Rate is set to 3 to 1 for all options.

Q. **Which option is being used for setting the Domestic TOU Rate and the Domestic EV TOU Rate?**

A. The Company is proposing to utilize Option 4. This option provides for three time periods, contains a peak period of five hours, and an off-peak and mid-peak differential that is material. Further, the cost causative components of this TOU rate, the generation and transmission components, result in a 2.23 to 1 ratio for the "whole house" TOU rate. As such, this option aligns most closely with principles of cost causation.

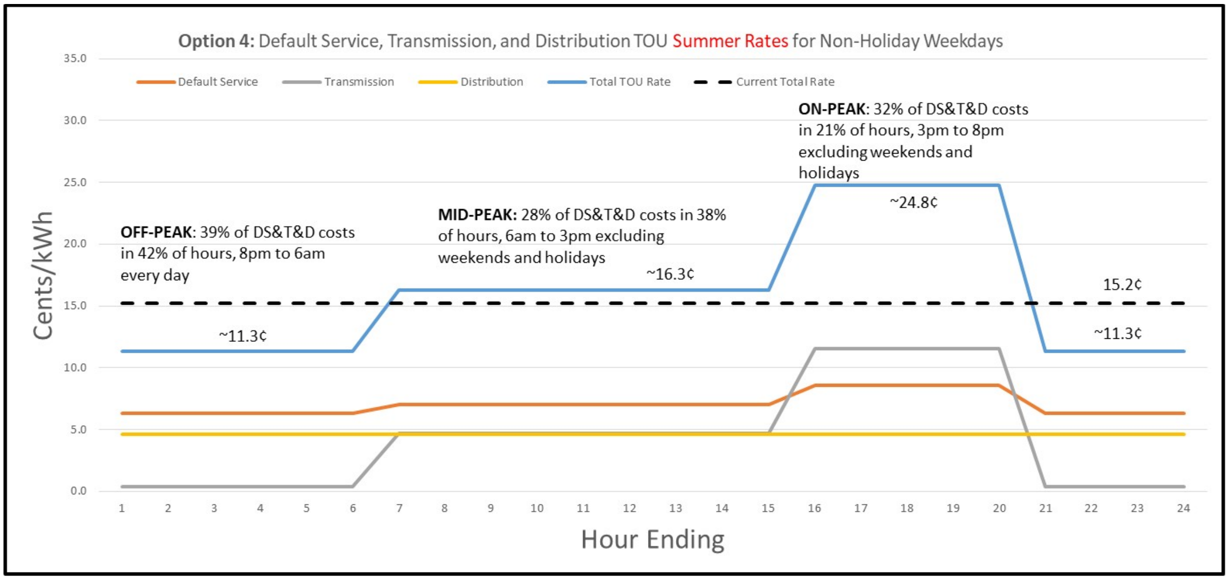
Q. **Can you please summarize the two proposed rates for Domestic TOU and Domestic EV TOU?**

A. The Domestic TOU Rate and the Domestic EV TOU Rates are shown in Table 3 below and contain the three components of the rates. Figures 1 & 2 below show the Domestic TOU Rates and Domestic EV TOU Rates by season. It should be noted that the rates are illustrative as the default service and transmission rates will be at different levels when permanent rates become effective.

Table 3 – Domestic TOU Rate Summary by Component

TOU Period	Default Service Retail TOU Rates ($/kWh)	Transmission TOU Rates ($/kWh)	Flat Distribution TOU Rates ($/kWh)	Total Domestic TOU Rates (w/flat Dist rate) ($/kWh)	Distribution TOU Rates for 3:1 ($/kWh)	Total Domestic EV TOU Rates (w/ Dist TOU Rates) ($/kWh)
Summer_Super-peak	-	-	-	-	-	-
Summer_Peak	0.08594	0.11567	0.04622	0.24783	0.08797	0.28958
Summer_Off-peak	0.06304	0.00408	0.04622	0.11334	0.02941	0.09652
Summer_Mid-peak	0.07003	0.04683	0.04622	0.16308	0.04941	0.16626
Winter_Super-peak	-	-	-	-	-	-
Winter_Peak	0.11167	0.16224	0.04622	0.32013	0.09213	0.36604
Winter_Off-peak	0.08606	0.00629	0.04622	0.13857	0.02965	0.12199
Winter_Mid-peak	0.09655	0.00792	0.04622	0.15069	0.04965	0.15412

Figure 1 – Domestic TOU Rates by Season



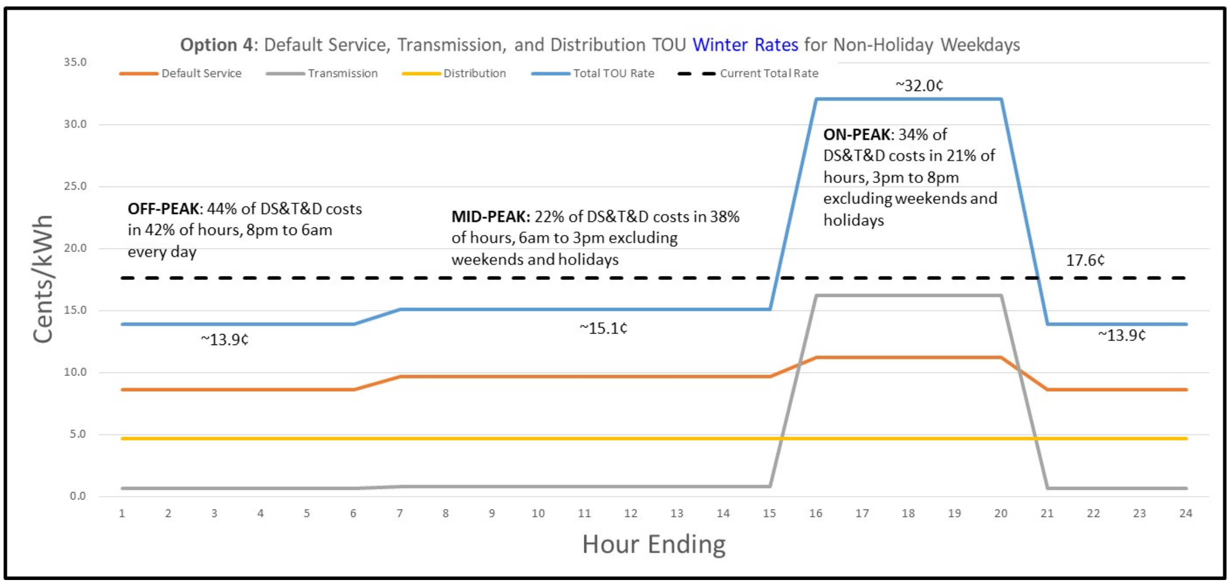
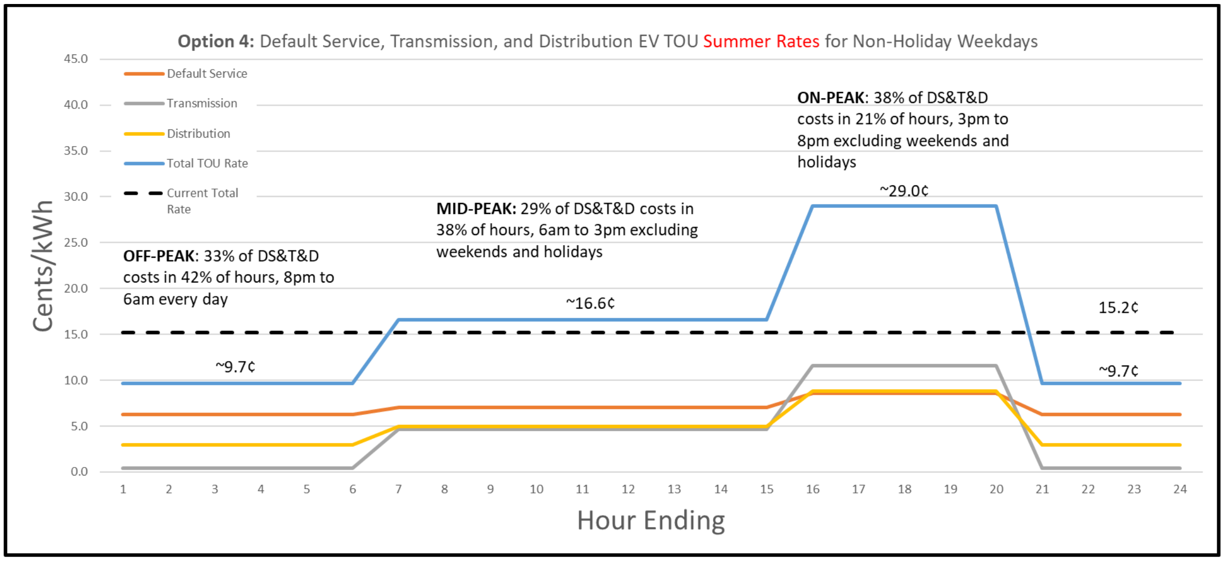
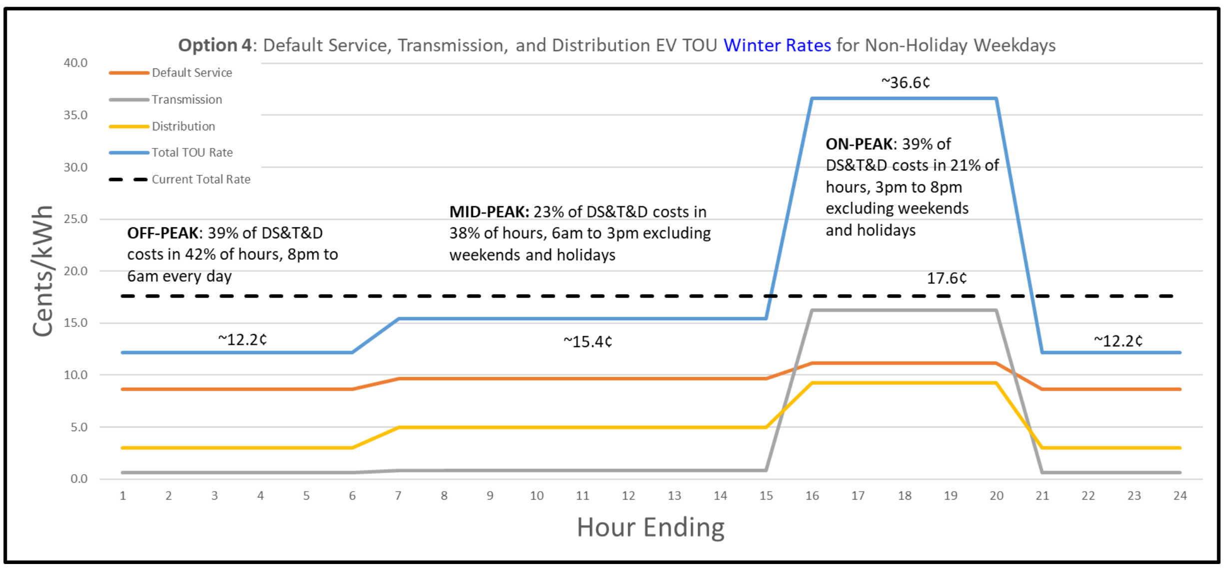


Figure 2 – Domestic EV TOU Rates by Season





Q. **What will the customer charges be for customers on either of these TOU Rates?**

A. The customer charge for the Domestic whole house TOU rate will be the same as the Domestic customer charge. The incremental customer charge for the EV Domestic TOU rate is set at $5.26 which represents the carrying cost associated with a separate meter required to meter the EV charging port.

Q. **What is the process of updating these rates when costs for the generation component and the transmission component are updated?**

A. As UES updates its default service and transmission rates, it will need to update the TOU Rate tariff given the total TOU rates are time varied for the generation component and transmission component. If the proposed TOU rates are approved the ratios set in this proceeding will be used to scale the changes in generation default service costs and transmission costs.

Q. **What analysis was utilized to determine the EV TOU Rates for non-residential charging facilities?**

A. The same method was employed EV TOU Rates for non-residential charging facilities. The same analyses described above for the Domestic TOU Rates were conducted for the generation component and the transmission component within the Excel TOU model, but utilizing data for the G1 and G2 rate classes. The rates developed for EV Charging stations below 200 kVA utilized data from the G2 class whereas the stations with over 200 kVA in demand utilized data from the G1 class. One challenge with modeling the G1 rate class is that the overwhelming majority of G1 customers receive energy from third party suppliers so only the Transmission costs were time-differentiated.

Q. **What are the proposed EV TOU Rates for non-residential charging stations?**

A. The resulting TOU rates for charging stations with <200 kVA are provided below in Table 4 and for charging stations with >200 kVA demand are provided within Table 5.

Table 4 – Proposed TOU Rate for EV Stations with < 200 KVA Demand

TOU Period	Default Service Retail TOU Rates ($/kWh)	Transmission TOU Rates ($/kWh)	Total EV <200 KVA TOU Rates ($/kWh)	Demand Rate ($/kW)
Summer_Super-peak	-	-	-	-
Summer_Peak	0.07378	0.14354	0.21732	11.59
Summer_Off-peak	0.05278	0.00408	0.05686	11.59
Summer_Mid-peak	0.06035	0.03717	0.09752	11.59
Winter_Super-peak	-	-	-	-
Winter_Peak	0.10393	0.17816	0.28209	11.59
Winter_Off-peak	0.07937	0.00647	0.08584	11.59
Winter_Mid-peak	0.09063	0.00699	0.09762	11.59

Table 5 - Proposed TOU Rate for EV Stations with > 200 KVA Demand

TOU Period	Default Service Retail TOU Rates ($/kWh)	Transmission TOU Rates ($/kWh)	Total EV >200 KVA TOU Rates ($/kWh)	Demand Rate ($/KVA)
Summer_Super-peak	-	-	-	-
Summer_Peak	-	0.14117	0.14117	8.37
Summer_Off-peak	-	0.00408	0.00408	8.37
Summer_Mid-peak	-	0.03867	0.03867	8.37
Winter_Super-peak	-	-	-	-
Winter_Peak	-	0.18569	0.18569	8.37
Winter_Off-peak	-	0.00646	0.00646	8.37
Winter_Mid-peak	-	0.00721	0.00721	8.37

In addition to the time-differentiated kWh rates these customers would also be charged a non-time-varying demand rate in alignment with the demand rates for the G1 or G2 rates and the standard customer charge for the G1 or G2 rates. These rates are also illustrative as a new transmission rate would be in effect at the time permanent rates are implemented.

Q. **What unique considerations are taken into account when developing the EV TOU Rates for non-residential charging stations?**

A. There is a higher degree of uncertainty with respect to the charging stations' load profiles, which directly impact their total bills under a TOU rate structure. Further, these charging stations may have limited ability to control or move demand from one time period to another (i.e., their price elasticity can be very low). With regard to load profiles, a workplace or retail host may see demand for charging during the day; whereas a multi-family or condo may have a similar load profile as a residential EV charging port (unless the multi-family or condo parking is in close proximity to retail or workplace in which EV owners can charge during the day as well). Thus, the role of TOU rate differentials in moving demand and consumption to off-peak hours is less predictable across the charging stations and can vary greater from one charging station to another.

Q. **Are demand related charges a significant portion of EV charging facility operating costs?**

A. They can be. Charging facilities, and especially fast charge stations, can result in a high peak demand due to their elevated power level to achieve quicker charging. Demand charges are an increasingly common part of rate structures offered by utilities which charge for the fixed distribution equipment necessary to meet peak demands based on the customer's peak demand (typically based on the maximum amount of power consumed by a customer during a 15-minute period). If a charging station has a low utilization rate (time during a month in which EV owners are charging at the station), the demand portion of their bill can be substantially higher than the actual energy costs. 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. Such a rate structure may make the economics of EV stations challenging, particularly during the early days of charger installation where EV market penetration is still relatively low. As the number of EVs increase, the likelihood of increasing load factor for these chargers is more likely, resulting in a better balance of energy/demand charges.

Q. **How can these hurdles caused by demand charges impact the electrification of the transportation industry?**

A. These hurdles for early stage charging investment demonstrate the dilemma that tends to follow EVs, where consumers are less likely to buy EVs if chargers are not readily available, but entities are less likely to build those capital-intensive chargers until greater market penetration of EVs increases their ability to recoup their initial cost. The current market for EV charging investment leads some owners to weather early costs from demand charges and low utilization. EV charging availability today will allow for more EV purchases in the future until increasing market penetration and charging station revenues can outweigh the early costs before the end of the lifetime of the charger.

Q. **What tools have been utilized by utilities to address this demand charge dilemma?**

A. Some utilities are utilizing a concept commonly referred to as a demand charge holiday. These are programs where utilities discount demand charges assigned to EV charger networks for a period of time until utilization rates rise and the chargers are economically viable. The actual structure and implementation of a demand charge incentives vary across the country. Options exist for indefinite demand charge holidays to reduce demand charges for EV chargers that ramp up over time to more complicated ways to adjust rate structures for EV infrastructure in a way that accounts for charging utilization. Demand charge holidays have not been the only type of assistance to EV charger networks proposed. Pacific Gas & Electric, for example, required EV operators to predict their monthly power use and then charged customers overage fees if they exceeded that total, similar to a subscription model. New York, on the other hand, offered upfront rebates intended to offset demand charges. There are also proposals to adjust demand charges based on charger utilization rates.

Q. **Can you please provide some examples of electric utilities providing a demand charge holiday for EV charging facilities?**

A. Below I summarize three demand charge holiday programs by (1) Southern California Edison (2) PECO Energy Company in Pennsylvania, and (3) PSE&G in New Jersey. Southern California Edison offered a five-year, 100% demand charge holiday intended to relieve the demand charge burden for EV chargers through 2024, while giving customers time to develop their load management plans. [6] After 2024, the demand charges would gradually ramp up over a five-year period until they reached a new

[6] Nelder, C. (2018). *Rate Design Considerations For EV Charging*. Presented at ACEEE National Convening on Utilities and Electric Vehicles, Atlanta, GA. Retrieved from https://aceee.org/sites/default/files/pdf/conferences/ev/nelder.pdf.

demand charge 40% below the current demand charge rate (which would ideally, at that point, no longer be overly burdensome because utilization rates had increased).[7] PECO Energy Company offers commercial EV chargers a credit against demand charges for three years, with participants able to take advantage of the holiday between 2019 and 2024. The credit equals 50% of the charger.[8] In Rhode Island, National Grid issued credits to offset 100% of demand charges for three years. After this three-year holiday, a distribution demand charge rate would be proposed based on currently available [9] PSE&G in New Jersey offered rebates towards demand charges for EV charger energy consumption, from an available pool of $5 million. The rebates are offered quarterly and will represent 75% of monthly distribution demand charges during the first two years of the program and 50% thereafter (until the $5 million is depleted).[10]

Q. **What is UES proposing with respect to demand charges for new EV charging facilities?**

A. The Company is proposing a demand charge holiday for charging facilities that will provide a 75% discount for the customer's first year of enrollment in the rate, a 50% discount during the second year, and a 25% discount during the third year on the

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[7] State of California Public Utilities Commission, Decision 18-05-040 dated May 31, 2018, Application 17-01-020 date of issuance June 6, 2018. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF

[8] Harper, C., McAndrews, G. & Byrnett, D. S. (2019). *Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators*. National Association of Regulatory Utility Commissioners (NARUC). https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE

[9] National Grid. Rhode Island Discount Pilot for DCFC Stations. https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/ee7873-ri-discount-pilot-for-dcfc-stations.pdf

[10] State of New Jersey Board of Public Utilities. BPU Docket No. EO18101111. Agenda Date: January 27, 2021. Agenda Item: 8A. https://www.state.nj.us/bpu/pdf/boardorders/2021/20210127/8A%20-%20ORDER%20PSEG%20EV%20Filing.pdf

charging stations demand charges. After the third year, the full demand charge will be applicable.

Q. **Are there other mechanisms that can be employed to lower the demand charges for non-residential charging stations?**

A. Yes. There are a number of technologies available to charging station owners that allow for more control of charging infrastructure to 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. While this technology may not be viable for some charging stations, it does provide the possibility to reduce the overall peak demand of a station for those that choose this additional capital investment and service.

Q. **Have you prepared any bill impacts relating to the EV TOU Rates?**

A. Yes. I have prepared bill impacts for the Domestic EV TOU Rate, the EV TOU Charging Station rate for stations with < 200 kVA and the rate for those stations with >200 kVA. Table 6 below, presents a residential EV rate under the current Domestic tariff and under the EV TOU Rate with no-control of charging periods and presents the same analysis assuming the EV owner controls their charging time (i.e., starts the charge during the off-peak period which can be automatically set for some EVs and charging ports). Further, this analysis was conducted for four typical daily driving amounts: 15 miles (light driver); 30 miles (average driver); 50 miles (heavy driver); and 100 miles (Lyft/Uber driver) with an assumed efficiency of 27 kWh per 100 Miles.

Table 6 – Residential EV TOU Uncontrolled vs. Controlled Charging

Winter - Avg Month	*Uncontrolled Load Profile (charging 3pm-9pm)*				*Controlled/TOU Load Profile (charging 8pm-2am)*			
Driver Profile	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**
Light Driver	$ 21.38	$ 42.78	-100%	$ (21.40)	$ 21.38	$ 14.82	31%	$ 6.56
Average Driver	$ 42.76	$ 85.56	-100%	$ (42.80)	$ 42.76	$ 29.64	31%	$ 13.12
Heavy Driver	$ 71.27	$ 142.60	-100%	$ (71.33)	$ 71.27	$ 49.41	31%	$ 21.87
Lyft/Uber	$ 142.55	$ 285.20	-100%	$ (142.65)	$ 142.55	$ 98.81	31%	$ 43.73
Summer Avg Month	*Uncontrolled Load Profile (charging 3pm-9pm)*				*Controlled/TOU Load Profile (charging 8pm-2am)*			
Driver Profile	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**
Light Driver	$ 18.46	$ 33.84	-83%	$ (15.38)	$ 18.46	$ 11.73	36%	$ 6.73
Average Driver	$ 36.92	$ 67.69	-83%	$ (30.77)	$ 36.92	$ 23.46	36%	$ 13.46
Heavy Driver	$ 61.53	$ 112.81	-83%	$ (51.28)	$ 61.53	$ 39.09	36%	$ 22.44
Lyft/Uber	$ 123.07	$ 225.62	-83%	$ (102.56)	$ 123.07	$ 78.18	36%	$ 44.88

As can be seen from the above tables, if a residential EV owner charges during the off-peak time, there are demonstrated savings.

Q. **What bill impacts were prepared for the non-residential EV charging stations?**

A. As discussed above, there are technologies available for an EV charging station to reduce their overall peak demand. Table 7 provides two assumed load profiles for a hypothetical work location with ten level 2 charging ports and an average monthly of 18,000 kWh with a monthly peak demand of 164 kW and 124 kW. One load profile assumes no load control and the other assumes load control equipment and program in place.

Table 7 – EV Charging Station with No Load Control and with Load Control

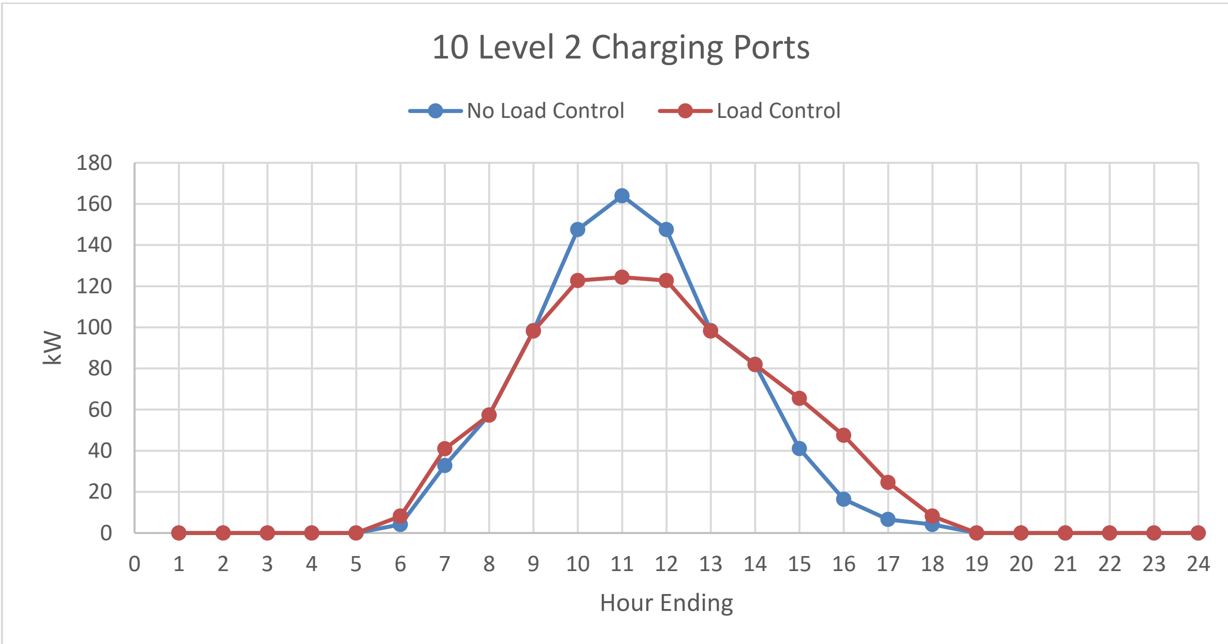

Table 8 below provides an analysis of the resulting total monthly bill for an EV charging station with the two above load profiles; when this customer elects to take service under the EV TOU Rate.

Table 8 – EV Charging Station <200 kVA Customer Avg Month Bill Impacts

Charges	Uncontrolled Load Profile	Controlled Load Profile (24% kW peak reduction)	Savings ($)
Customer Charge ($/month)	$ 32.20	$ 32.20	$ -
Demand Charge Cost ($)	$ 1,900.00	$ 1,441.37	$ 458.63
TOU Energy Charge Cost ($)	$ 1,816.83	$ 1,940.81	$ (123.98)
Total Bill	**$ 3,749.04**	**$ 3,414.39**	**$ 334.65**

The ability to reduce the peak demand by 24 percent can result in a 9 percent savings on the total bill (i.e., $334 divided into $3,749). This same load profile is then used to review the impact of the demand discount which results in an average monthly savings of $1,081 during the first year down to $360 during the last year of the demand holiday program, as presented in Table 9 below.

Table 9 – Demand Discount for Non-Residential EV Charging Station

Controlled Load Profile	Total Bill	w/Demand Discount	Savings ($)
Total Bill w/75% demand cost reduction	$ 3,414.39	$ 2,333.36	$ 1,081.03
Total Bill w/50% demand cost reduction	$ 3,414.39	$ 2,693.71	$ 720.69
Total Bill w/25% demand cost reduction	$ 3,414.39	$ 3,054.05	$ 360.34

Q. **Are similar conclusions reached when reviewing bill impacts for an EV charging station with demand over 200 kVA?**

A. Yes. The same conclusions can be seen in Table 10 below, where a hypothetical DC Fast Charge station was modeled. There are increases to the transmission portion of the customer's bill when moving between the current rate and TOU rates. There are no energy supply costs assumed given that the vast majority of large energy users with greater than 200 kVA utilize third party energy suppliers.

Table 10 – Bill Impact for Large EV Charging Station with >200 kVA

>200 KVA Charging Station	Current Energy Rate	TOU Energy Rate	Savings ($)
Customer Charge - Primary Voltage ($/month)	$ 95.42	$95.42	$ -
Demand Charge Cost ($)	$ 1,823.45	$ 1,823.45	$ -
Transmission Charge Cost ($)	$ 2,256.81	$ 3,566.07	$ (1,309.26)
Total Bill	**$4,175.69**	**$5,484.94**	

	Total Bill	w/Demand Discount	Savings ($)
Total Bill w/75% demand cost reduction	$ 5,484.94	$ 4,117.35	$ 1,367.59
Total Bill w/50% demand cost reduction	$ 5,484.94	*$ 4,573.22*	$ 911.73
Total Bill w/25% demand cost reduction	$ 5,484.94	*$ 5,029.08*	$ 455.86

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

A. TOU rates impact customers in different ways depending on their load profile, their peak demand, and the utilization of the station. 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). Further, the demand component of their bills can be a large portion of total costs and prohibitive in the development of these stations. The TOU rates proposed by the Company and detailed in this testimony present an opportunity to shift load for those stations with the ability to shift, resulting in societal cost savings and reducing customer bills. In addition, a demand charge holiday can provide an incentive for the development of charging stations supporting the electrification of the transportation industry.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.