STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 19-057

IN THE MATTER OF: **PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY**

Distribution Service Rate Case

DIRECT TESTIMONY

OF

SANEM I. SERGICI

December 20, 2019

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I. STATEMENT OF QUALIFICATIONS

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

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

Q. Please describe your professional experience and educational background.

A. I am an energy economist with sixteen years of consulting and research experience. My consulting practice is focused on understanding customer adoption of and response to innovative rate designs and emerging technologies. I regularly assist my clients on matters related to retail rate design, big data analytics, grid modernization investments, resource planning and alternative ratemaking mechanisms. I have a Ph.D. in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. I received my M.A. in Economics from Northeastern University, and B.S. in Economics from Middle East Technical University (METU), Ankara, Turkey. A statement of my qualifications is included in Attachment SIS-1.

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

A. Yes. I submitted direct testimony on behalf of the New Hampshire Public Utilities Commission Staff on rate design in Docket DE 19-064.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the New Hampshire Public Utilities Commission Staff.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to comment on the methods used to develop class revenue allocations and design of proposed permanent rates by Witness Davis for Eversource Energy (the "Company").

Q. What are the major findings from your analyses?

A. Major findings of my analyses are as follows:

- The Company uses an equalized rate of return ("ROR") approach to move each class revenue allocation to the class average. While the methodology applied by Witness Davis to arrive at RORs closer to unity is not formulaic and somewhat ad hoc, the outcome moves each rate class closer to unity in a relatively balanced manner.
- The Company should rely on the marginal cost of service ("MCOS") study for rate design and move towards more cost reflective rates, which encourage economic efficiency and market-enabled decision making for both operations and new investments, in a technology neutral manner.
- The Company should revise the revenue allocation for the Rate LG for which ROR allocated revenues are substantially different from the MCOS allocated revenues.
- The Company should increase the customer charges further for Rate GV and Rate LG to achieve a better alignment with the MCOS based customer charges.
- The Company should revise the TOU rate design to more closely mirror the time periods and seasonality identified in the MCOS study. Witness Nieto's proposed Option B constitutes a good starting point for the revision of the TOU rate design.
- The Company should try to minimize unintended intra-class subsidies by cost reflective rate design, and analyze costs and benefits of metering infrastructure that would enable these advanced rates for residential customers.

Q. How is your testimony organized?

A. Section III discusses the principles of rate design. Section IV evaluates the Company's approach to determine the class revenue allocations for rate design. Section V evaluates the Company's proposed rate design and its conformity with the principles of rate design.

III. PRINCIPLES OF RATE DESIGN

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

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

1. *Economic Efficiency* **–** The price of electricity should convey to the customer the cost of producing it, ensuring that resources consumed in the production and delivery of electricity are not wasted. If the price is set equal to the cost of providing a kWh, customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the development and adoption of energy technologies that are capable of providing the most valuable services to the power grid, and thus the greatest benefit to electric customers as a whole.
2. *Equity* **–** There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat rate pricing structures (i.e., cents/kWh). Since customers have different load profiles, "peaky" customers, who use more electricity when it is most expensive, are subsidized by less "peaky" customers who overpay for cheaper off-peak electricity.
3. *Revenue Adequacy and Stability* **–** Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost-reflective.
4. *Bill Stability* **–** Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time. For example, if fixed infrastructure costs are spread over a certain number of kWhs in Year 1, and

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

the number of kWhs halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure cost of the utility.

5. *Customer Satisfaction* – Rates should enhance customer satisfaction. Because most residential customers devote relatively little time to reading their electric bills, rates need to be relatively simple so that customers can understand them and perhaps respond to the rates by modifying their energy use patterns. Giving customers meaningful cost reflective rate choices helps enhance customer satisfaction.

Q. Is there an overriding principle that underlies the Bonbright principles?

A. Yes, it is the principle of cost causation. What this means is that rates should reflect the structure of the costs that are incurred to serve them. Ideally, fixed costs should be recovered through a fixed monthly charge, capacity costs through a demand charge and energy costs through an energy (volumetric charge). However, there might be practical constraints such as lack of advanced metering infrastructure that might prevent the implementation of purely cost reflective rates.

IV. DETERMINATION OF CLASS REVENUE ALLOCATIONS

Q. From an economic perspective, how should the class revenue allocations be determined to encourage economic efficiency?

A. As indicated in the NARUC Cost of Service Manual, "the major reason for allocating costs using marginal costs principles is to promote economic efficiency and social welfare by simulating the pricing structure and resource allocation of a competitive market."[2] This implies that determining the class revenue allocations based on marginal cost of service would maximize economic efficiency.

Q. Is it possible to implement class revenue allocations and design rates purely based on the marginal costs?

A. While it is theoretically possible to design rates purely based on the marginal costs, it is practically never done. The reason simply is that marginal costs and embedded costs

[2] NARUC Electric Utility Cost Allocation Manual (1992).

are almost never equal, and designing the rates based on marginal costs may lead to over or under collection of the revenues.

Q. How are the results of a marginal cost study used to inform rate design?

A. Since the revenues that would be collected under marginal cost-based rates will not precisely coincide with the revenue requirements permitted under an embedded cost of service study, it is necessary to modify the class revenue allocations in a way to conform to the revenue requirement. This adjustment is called "revenue reconciliation." There are four widely used revenue reconciliation methods in the literature: i) inverse elasticity; ii) lump-sum transfer; iii) differential adjustment of marginal cost components; and iv) equi-proportional adjustment. The goal in revenue reconciliation should be to do the least harm to the efficiency of the marginal cost-based rates.

Q. Did Witness Davis use a marginal cost approach to develop class revenue allocations?

A. No. Witness Davis's approach to class revenue allocations is based on each customer class ideally providing the same ROR. This approach compares the return from each class relative to its allocated share of rate base. The resulting class-based RORs are compared to the company average ROR to determine if a customer class is generating higher or lower returns than the company's overall average. To facilitate that comparison, the class-based ROR is divided by the company-average ROR, and the resulting quantity is referred to as the "unitized class-ROR." A unitized class-ROR of one means that the class has the same ROR as the company's average. A unitized class-ROR of less (more) than 1 indicates that the class's returns are less (more) than the company average. Witness Davis determines class revenue allocations such that unitized class RORs for each of the classes are brought closer to 1.[3]

[3] Direct Testimony of Edward A. Davis, Request for Permanent Rates, Docket No. DE 19-057. Further captured in Company's rate design workbook.

Q. How did Witness Davis apply the rate of return approach to develop class revenue allocations?

A. Witness Davis's approach to class revenue allocations is somewhat *ad hoc* but in alignment with moving toward equalized RORs for all rate classes. Of the ten rate classes, the Residential (Rate R & R-TOD), Water Heating (Rate R-WH and Rate G-WH), and Load Control Service (Rate R-LCS and Rate G-LCS), have unitized RORs less than one. For these three rate classes, Witness Davis allocates a greater than average increase in class revenue requirement and "directly assigns" the allocations. Witness Davis caps the revenue allocation increase for all classes at 120% of the average increase of 19.9% (amounting to a total allocated revenue increase of 24%) to preserve rate gradualism.[4] For the Residential class, Witness Davis assigns a revenue allocation of 120% of the average revenue requirement increase (equal to 24% total change in revenue requirement relative to current rates). For the Water Heating class, Witness Davis assigns a 119% of the average revenue requirement increase (equal to 24% total change in revenue requirements relative to current rates).[5] Finally, Witness Davis allocates the Load Control Service an increase of 113% of the average revenue requirement increase (equal to 22.5% total change in revenue requirements relative to current rates). An approach purely driven by equal RORs would assign the Load Control Service class the maximum increase (120%) as the current ROR for the class is negative.

With these revenue allocations set, Witness David allocates the remainder of the revenue requirement increase to the classes with unitized RORs greater than one.

[4] In data request OCA 6-108, Witness Davis states, "Limiting the revenue requirement increase in each class to no more than 24% provides a degree of gradualism for each class…" and in data request Staff 14-011 states that, "The Company relied on experience and judgement, and general proportions of revenue requirements among classes, in developing revenue allocations jurisdictions to determine that the 20% above average increase was reasonable for rate classes with significantly lower Rate of Return's…"

See Attachment SIS-4 (Response to OCA 6-108) and Attachment SIS-5 (Response to Staff 14-011).

[5] The Company has proposed to close Rate Controlled Water Heating as it no longer controls water heaters and migrate customers to the rates for Rate Uncontrolled Water Heating.

See Davis Testimony pages 13-14; Bates 01809-01810

Q. How did Witness Davis allocate the remaining increase in revenue requirement to the classes with a unitized ROR of greater than one?

A. First, Witness Davis modified the revenue allocation for the lighting classes to achieve a unitized ROR of one. He then distributed the remaining rate increase to the other classes in proportion to their return using the new Company based ROR.[6]

Q. Is the primary goal of the ROR approach to develop economically efficient rates?

A. No. A rate design approach that attempts to produce equalized RORs places a greater emphasis on achieving equitable contribution from individual classes rather than achieving economically efficient signals. If all customer groups were homogenous, equal RORs across customer groups would represent a "fair" rate design. In practice, there may be reasons that may justify different RORs. By its nature, the equalized ROR approach is backward looking, comparing the class's return to its allocated share of rate base. By contrast, MCOS-based rates are forward looking and are explicitly developed to reflect going-forward economically efficient price signals. Nevertheless, rate design that moves toward equalized RORs is commonly used in the industry.

Q. Can the MCOS based revenue allocation approach and rate of return approach result in similar allocations of class revenues?

A. Yes, but by coincidence rather than design. If the current rates are not reflective of marginal costs or ROR, and both are in the same direction, using the approaches would notionally move the revenue allocations in the same way. The degree to which the two approaches move the revenue requirement allocations in the same direction is dictated by the alignment between the underlying ROR and MCOS for each class as well as the application of rate increase caps to provide bill stability.

Q. For Eversource, do the class revenue allocations produced by a MCOS approach agree with those based on an equalized ROR approach?

[6] This calculation is shown in Davis Exhibit EAD-5 p.2 Aloc WP lines 19-34.

A. Only directionally for some rate classes. Equalized ROR and MCOS approaches move the revenue allocations in the same direction for 7 of 10 rate classes. As shown in Figure 1, while these changes are directionally aligned, they do not agree in overall magnitude.[7] For example, the class revenue allocations for Large General Service (Rate LG) is almost five times larger under an equalized ROR approach (shown in column 3) than based on an MCOS approach (shown in column 2). Thus, although the revenue allocations align directionally in this specific rate case, the pursuit of an equalized ROR approach would not arrive at economically efficient signals in the long run.

Directionally, 3 of 10 classes do not align (Water Heating (Rates R-WH and G-WH), General Service (Rates G & GTOD), and Primary General Service (Rate GV)), indicating that movement toward an equalized ROR approach produces revenue requirement allocations contrary to those reflecting economically efficient price signals.

[7] Note that the MCOS values cited here rely on the Eversource study, which uses a 75% loading criteria. I understand that the testimony of Staff witness Kurt Demmer is addressing the appropriateness of a 75% loading criteria. Further, I understand that in his testimony, Staff witness Agustin Ros addresses additional methodological issues with the Eversource MCOS study. However, the issues raised by both witnesses do not address my fundamental analysis or conclusions.

Figure 1: Comparison of Revenue Allocations based on MCOS and ROR Approaches

Rate Class	Current *(Rev $000)* [1]	MCOS *(Rev $000)* [2]	Equalized ROR *(Rev $000)* [3]	Proposed *(Rev $000)* [4]	MCOS - Current *(Rev $000)* [5] = [2] - [1]	ROR - Current *(Rev $000)* [6] = [3] - [1]
Rates R & R-TOD	197,370	288,408	278,239	244,613	91,039	80,869
Rate R-WH & G-WH	4,332	2,770	5,713	5,362	-1,562	1,381
Rate LCS R&G	476	531	1,582	584	54	1,106
Rate G & G-TOD	83,945	85,020	78,393	97,722	1,075	-5,552
Rate G-SH	202	90	198	237	-112	-4
Rates GV	36,212	36,622	31,063	42,296	411	-5,149
Rate LG	18,846	3,773	18,242	22,369	-15,073	-604
Rate B GV&LG	1,519	29	804	1,668	-1,490	-715
Rate OL	4,509	2,843	4,040	4,047	-1,666	-469
Rate EOL	3,082	318	1,502	1,507	-2,764	-1,580
Total Company	**350,492**	**420,405**	**419,776**	**420,405**	**69,913**	**69,284**

Sources and Notes:
Figure relies on data from Company's rate design workbook and Company's MCOS and ACOS analyses.
Equalized ROR revenue requirement reflect level necessary to achieve 7.62% return across all classes.
MCOS revenue requirements based on class shares from Company's MCOS analysis applied to proposed revenue requirement.

Q. Do the proposed rate changes move all classes closer to unitized RORs under the Company's proposal?

A. Yes. All 10 classes move closer to unitized RORs of 1 as shown in Figure 2. The most notable changes in unitized ROR are for the Outdoor Lighting class (Rate EOL), which move from unitized ROR of 14.5 to 1.0.

Figure 2: Impact of Proposed Revenue Requirements on ROR

	Rate of Return			Current to Proposed Change	
Rate Class	Current	Proposed	Unitized ROR	Overall RoR Change	Makeup Towards Allocated Cost
	[1]	[2]	[3]	[4]	[5]
Rates R & R-TOD	0.1	0.6	1.0	805%	57%
Rate R-WH & G-WH	0.3	0.8	1.0	132%	67%
Rate LCS R&G	-2.8	-1.1	1.0	-63%	46%
Rate G & G-TOD	2.7	1.8	1.0	-33%	53%
Rate G-SH	2.3	1.6	1.0	-30%	52%
Rates GV	3.3	2.1	1.0	-37%	53%
Rate LG	2.4	1.7	1.0	-31%	52%
Rate B GV&LG	8.1	4.2	1.0	-48%	54%
Rate OL	3.3	1.0	1.0	-70%	100%
Rate EOL	14.5	1.0	1.0	-93%	100%
Total Company	**1.0**	**1.0**	**1.0**	**0%**	

Sources and Notes:
Figure relies on data from Company's rate design workbook
[4] = ([2] - [1]) / [1]
[5] = ([2] - [1]) / ([3] - [1])

Q. Do you have any concerns with how Witness Davis applied the ROR approach to determine the class revenue allocations?

A. No. While the methodology applied by Witness Davis to arrive at RORs closer to unity is not formulaic and somewhat ad hoc, the outcome moves each rate class closer to unity in a relatively balanced manner. Though the revenue allocations for 8 of 10 classes are still not completely aligned with their allocated costs, as can be seen in Column 5 of Figure 2, this is not uncommon in the application of class revenue allocations in the industry.

V. REVIEW OF RATE DESIGN

Q. Has Witness Davis proposed new rate structures for the rate classes?

A. No. The proposed rate structures mirror the current rate structures with the exception of outdoor lighting. Witness Davis states that "The decision to maintain current rate structure at this time is based on ensuring customer understanding and acceptability. Customers have become familiar with current rate structures, and it is important to assure that any further changes to rates are understandable and that reflect an appropriate level of continuity and gradualism."[8]

Q. Has Witness Davis considered cost-reflectivity in his approach to rate design?

A. No, it does not seem so. Witness Davis indicates that "…changes to rates determined through a number of overall rate changes which may not result in entirely cost-reflective rate structures for all customer classes."

Q. Since the rate structures were not modified, did Witness Davis follow a consistent and formulaic approach to determine how the increase in revenue requirement would be allocated to rate component (i.e., customer charge, demand charge, volumetric charge)?

A. No, Witness Davis applied an *ad hoc* set of changes. In general, one component of the rate (customer, demand, or volumetric) was held to a level similar as proposed in the temporary rates, which reflects a 9.4% increase,[9] and the remaining charges were increased to recover the outstanding class revenue requirement allocations. The specific choice for which rate component would remain at the temporary rate level was unique to each rate class. As shown in Figure 3, the residential rate classes (including Rate R, Rate R-OTOD, and Rate R-UWH) generally have the customer charge held constant at the temporary rate levels and the remaining revenue increase is recovered through the volumetric charge.[10] For the general service customers, the proposed volumetric rates typically reflect the temporary rates and the remaining revenue is recovered through the customer and demand charges.

[8] Direct Testimony of Edward A. Davis, Request for Permanent Rates, Docket No. DE 19-057, p. 10 of 27 lines 1-5. Bates 001807.

[9] Direct Testimony of Edward A. Davis, Request for Temporary Rates, Docket No. DE 19-057, p. 6 of 10 lines 2-4 Bates 000477.

[10] With regard to time of day rates, while the differential between peak on-peak and off-peak remain similar (from $0.13/kWh to $0.14/kWh), the ratio between on-peak and off-peak prices has decreased significantly from 69:1 to 14:1.

Figure 3: Percentage Change in Rate Components by Rate Class

Rate	Customer	Volumetric	Demand
Rate R	9.46%	31.39%	-
Rate R OTOD	9.43%	22.98%	-
Rate UWH	9.40%	41.63%	-
Rate CWH	-37.94%	1148.33%	-
Rate LCS	24.04%	24.17%	-
Rate G P&L	20.94%	9.44%	20.41%
Rate G TOD	9.44%	9.45%	17.37%
Rate G Space	9.40%	18.01%	-
Rate GV	16.81%	9.42%	19.87%
Rate LG	18.70%	9.50%	22.74%
Rate B	9.44%	-	9.82%

Sources and Notes:
Figure relies on data from Company's rate design workbook.
Block rates are averaged to allow for single percent change figure.
Water heating and load control service (radio controlled) are same across R and G customers.

Q. The rate components for Water Heating and Load Control Service have significant changes in both fixed and volumetric rates. Why do these classes differ?

A. As described earlier, the Company states that it no longer controls water heaters,[11] so the rate structure for controlled water heating (Rates R-CWH and G-CWH) is being transitioned to the rate structure for Uncontrolled Water Heating (Rates R-UWH and G-UWH). While I cannot comment on the value of the controllable water heating program as previously implemented by the Company, I do observe from industry studies that there is potentially significant value in controlling water heaters as a demand management approach.[12] The Company proposes that the rate transition take place in two steps. The first step, reflected in Figure 3 sets the customer charge equal to the Uncontrolled Water Heating class and increases the volumetric rate 50% toward

[11] Witness Davis Direct Testimony p. 12 lines 11-12, Bates 01809.

[12] See for example, R. Hledik, J. Chang, and R. Lueken, "The Hidden Battery: Opportunities in Electric Water Heating," Prepared for the National Rural Electric Cooperative Association, the Natural Resources Defense Council, and the Peak Load Management Alliance, January 2016.

the Uncontrolled Water Heating leading to a 1,148% increase. The second step, which the Company proposes for July 1, 2021, increases the volumetric rate to the level of the Uncontrolled Water Heating rate. Thus, the Company's proposal increases in the volumetric rate (relative to current rates) a total of 2,296% in July 2021. The Load Control Service rates (Rates R-LCS and G-LCS, excluding Radio Controlled), are proposed to transition to the same rate structure as Uncontrolled Water Heating.

For the Radio Controlled LCS service, Witness Davis elected to increase the customer and volumetric charges "using a comparable percentage increase."[13] The Company does not provide a specific rationale for increasing both charges in tandem. However, the Company does propose to close the rate to new applicants as Witness Davis states that the rate was developed for customers with "older technologies."[14]

Q. Do the proposed rate changes bring the customer charges closer to the economically efficient levels identified by Witness Nieto?

A. In part. As shown in Figure 4, the proposed customer charge for Residential (Rate R) and Residential Controlled Water Heating (Rate R-CWH) move toward the economically efficient level identified by Witness Nieto, while the customer charges for the other residential rates exceeded the levels identified by the MCOS prior to the rate increase and further increases by the proposed rate design. With regard to the proposed general service rates, the customer charges are all closer to the MCOS identified values excluding the Single Phase General Service rate (Rate G P&L-P1) and General Service Time of Use Rates (Rate G TOD-P1 and Rate G TOD-P3). While the proposed customer charges for Rate G-Space, GV and LG also get closer to the MCOS values, the proposed rates represent only a modest percentage of the MCOS based customer charges (18% and 58%, respectively).

[13] Direct Testimony of Edward A. Davis, Request for Permanent Rates, Docket No. DE 19-057, p. 13 of 27 lines 14-16, Bates 001810.

[14] As an example of older technologies, Witness Davis cites the "heat smart" program.
See Direct Testimony of Edward A. Davis, Request for Permanent Rates, Docket No. DE 19-057, p. 13 of 27 lines 16-20, Bates 001810.

Figure 4: Customer Charge Comparison

Rate	Current [1]	Proposed [2]	MCOS [3]	Current Percent of MCOS [4] = [1] / [3]	Proposed Percent of MCOS [5] = [2] / [3]	Alignment towards Marginal Cost [6]
Rate R	$12.69	$13.89	$14.91	85%	93%	54%
Rate R OTOD	$29.47	$32.25	$17.15	172%	188%	-23%
Rate UWH	$4.47	$4.89	$1.75	255%	279%	-15%
Rate CWH	$7.88	$4.89	$1.75	450%	279%	49%
Rate LCS	$9.11	$11.30	$2.39	381%	473%	-33%
Rate G P&L-P1	$14.89	$18.00	$15.04	99%	120%	2073%
Rate G P&L-P3	$29.76	$36.00	$32.64	91%	110%	217%
Rate G TOD-P1	$38.57	$42.21	$20.06	192%	210%	-20%
Rate G TOD-P3	$55.12	$60.32	$44.33	124%	136%	-48%
Rate G Space	$2.98	$3.26	$4.52	66%	72%	18%
Rate GV	$194.03	$226.65	$1,238.71	16%	18%	3%
Rate LG	$606.47	$719.88	$1,245.15	49%	58%	18%

Sources and Notes:
Figure relies on data from Company's rate design workbook and Company's MCOS analysis.
[6] = ([5] - [4]) / (100% - [4])
[6]: Positive values indicate proposed customer charge is closer to marginal cost than current customer charge; negative values indicate proposed customer charge is further from marginal cost than current customer charge.
[6]: Customer costs for Rates G P&L are very high because proposed customer charge goes from being less than marginal cost to more than marginal cost. This does not necessarily mean that the proposed customer charge is closer to marginal cost.

Q. Do you recommend any changes to the customer charges proposed by Witness Davis?

A. Yes. While there is room for improvement in most rates for better alignment with the marginal cost based customer charges, I recommend that the customer charges for Rate GV and LC classes are increased further, given that the magnitude of the difference between the proposed and MCOS-based customer charges is quite substantial. This adjustment would also help reduce volumetric rates and demand charges for these rate classes, and provide more efficient price signals for customer's consumption decisions.

Q. Did the Company incorporate the results of Witness Nieto's costing period analysis into the on-peak and off-peak rates for time of use rates?

A. No. The Company did not modify the on-peak and off-peak timing despite Witness Nieto's conclusion that the current pricing periods are "not appropriate."[15] The current time-of-use rates define on-peak hours as 7:00 AM through 8:00 PM for all weekdays excluding holidays. Witness Nieto identified and evaluated two alternative time of day and seasonal options (Option A and Option B) with improved correspondence with the underlying MCOS.[16] In Option A, the peak period is defined as 11 am through 7 pm to be applicable during the summer months defined as July and August. In Option B, the peak period is still defined as 11 am through 7 pm, but the summer months include June through September. By the way of spreading summer peak capacity marginal cost over the course of four months, the peak to off-peak differential is lower under Option B compared to Option A.

Witness Davis explained that the Company considered changes to the time of use rates in the "longer term" but did not opt to propose the changes in this rate case "due to keeping in mind all aspects of rate design which include consistency and continuity."[17]

Q. Did Witness Davis explain what constitutes "longer term" and present a plan for prioritizing cost reflectivity along with consistency and continuity?

A. No. Witness Davis did not offer any details around what constitutes longer term and a plan or requirements for prioritizing cost reflectivity along with rate consistency and continuity.

Q. Do you have a recommendation on how the TOU rate design should be revised?

A. Yes. The TOU rate design should be aligned with the marginal cost price signals identified in Company's marginal cost study. In addition to communicating efficient price signals, the design of the TOU rate should take into account customer experience

[15] At Bates 01771 (Attachment MCOS Report), Witness Nieto states, "The seasonality observed in the hourly marginal costs indicates that consideration of seasonality for Eversource's distribution rates may be required for efficient pricing. These results also show that the broad definition of the peak period in current rates (7am to 8pm, Monday through Friday), is not appropriate. Hours 11 am to 7 pm of summer weekdays include the highest marginal hourly distribution costs."

[16] See Witness Nieto's Attachment 1 (MCOS Report) at Bates 001771-001773.

[17] Attachment SIS-6 (Response to Staff 14-019).

with these rates, in terms of the length of the TOU window (too long of a window is generally difficult to manage from a customer experience perspective) as well as the ratio between peak and off-peak prices (while too high of a ratio might lead to a rate shock, too little of a ratio would not incentivize customers to respond to the TOU rates). Given these considerations, Witness Nieto's Option B represents a good starting point for the redesign of the TOU rate.

Q. Did Witness Davis analyze the impacts to customer bills of the proposed rate changes?

A. Yes, but only in part. Witness Davis calculated the class average total bill impact in Attachment EAD-7. In addition, Witness Davis calculated representative bill impacts relative to the temporary rates for different levels of consumption and demand in Attachment EAD-9 and provided the same analysis relative to current rates as part of an information request.[18] While these comparisons show the customer bill impact for certain levels of customer consumption and demand, they do not provide context on the number of customers at each level of consumption nor do they capture the complete range customers and impacts of the proposed rate increase. Figure 5 below presents the total customers for each rate class, the number of customers represented in Witness Davis's bill impact analysis (in Attachment EAD-9), the customers *not* represented in Witness Davis's bill impact analysis (in Attachment EAD-9) and the average rate impact analysis provided by Witness Davis (in Attachment EAD-7).

[18] See Attachment SIS-3 (Data Response Attachment Staff 14-010A).

Figure 5: Average Total Bill Impact by Customer Class

	Total Customers	Not Included in Customer Bill Analysis	Percent Not Included	Average Total Bill Impact
Rate R	445,391	32	0%	7.40%
Rate R OTOD	42	0	0%	7.76%
Rate G 1-Phase	57,296	9,480	17%	4.30%
Rate G 3-Phase	20,253	12,645	62%	4.30%
Rate G OTOD	38	11	29%	8.55%
Rate G Space	425	181	43%	3.60%
Rate GV	1,432	264	18%	2.04%
Rate LG	111	17	15%	1.85%
Rate G OTD (1-Phase)	15	0	0%	8.55%
Rate G OTD (3-Phase)	23	11	48%	8.55%
Rate R UWH	43,304	75	0%	5.97%
Rate G UWH	1,299	95	7%	5.90%
Rate R CWH	251	0	0%	-1.51%
Rate G CWH	-	-	-	-
Rate R LCS	3,486	1,119	32%	1.98%
Rate G LCS	192	96	50%	1.07%
Total Company	**573,558**	**24,026**	**4%**	

Sources and Notes:
Figure relies on data from Company's rate design workbook and customer count data from Attachment SIS-2 (Data Response Attachment Staff 14-010 B).
Customer counts and bill impacts were not provided for G CWH.
LCS rates reflect only the LCS Radio Controlled customers.

Q. How did you determine which customers are not captured in Witness Davis's bill impact analysis?

A. Customers are counted as not included (i.e., not represented) in the customer bill analysis if they could not be mapped to a corresponding range of demand and/or volumetric usage within the bill impact analysis. The customer count data provided by Witness Davis is "binned" into ranges using the characteristic usages included in Attachment EAD-9. When determining which customers are mapped to which bill impact, I assume customers map to the high end of their provided range (e.g., customers in a range of 101-200 kWh would map to the 200 kWh impact). For example, for Rate G LCS Radio Controlled, Witness Davis provides customer bill impacts for customers from 100 kWh to 1,000 kWh, providing a representative bill impact every 100 kWh. However, the customer count data shows that there are 96 customers with greater than 1,000 kWh (50% of the class). Since I do not know the range of consumption or approximate distribution of customers with consumption greater than 1,000 kWh, I cannot accurately determine the range of their bill impacts and, therefore, identify them as not included in the analysis. I similarly identify customers with demand that does not map to a corresponding range in the bill impact analysis.

Q. Based on the data provided by Witness Davis, is there significant variation in the bill impacts within classes on a total bill basis?

A. Yes, especially within the general service and water heating/load control rate classes. The range of rate impacts, as provided by Witness Davis, is shown in Figure 6. Note that the rate classes missing more than 25% of customers are shown as dashed, indicating the uncertainty relative to the total range of impacts.

As shown in Figure 6, the widest variation in rate impacts is for the customers on the controlled water heating rates. The proposed rate change for the controlled water heating classes (shown in the figure as Rate CWH) has two phases. Based on the data provided by Witness Davis, the range of bill impacts for the first phase of the rate increase produces impacts ranging from a decrease of approximately -8% to an increase of 7%. This range in impacts results from a decreased customer charge but increased volumetric rate. The first phase of the rate change includes a volumetric rate increase of more than tenfold. Under the proposed rate changes, customers in the controlled water heating classes will have a second rate change that further increases their volumetric rates.

Similarly, the radio controlled load control service customers have a wide variation in the range of total impacts, shown in the figure as Rate LCS. While the average impact is approximately a 2% increase, the highest impacts (as provided by Witness Davis) represent approximately a 10% increase. This range in impacts reflects the difference in the percentage of the bill from distribution versus other energy-related charges because the customer and energy chargers were both increased 24%. While the average energy usage of customers in the Radio Load Control Service rates sample provided by Witness Davis is 550 kWh, the average across the entire rate class is 873 kWh for residential (Rate R LCS Radio Controlled) and 1,900 kWh for general service (Rate G

LCS Radio Controlled). If the full set of customer information had been provided, the total bill impacts range would have been wider, with the largest customers showing bill rate impacts directionally closer to zero. This is because the volumetric portion of the customer's bill is approximately 1% distribution costs and 99% energy and transmission costs.[19] Thus a 24% change in the volumetric distribution rate cannot impact the total bill more than 0.24%.

The total bill impacts for the main general service rates (Rates G 1-Phase and G 3-Phase) range from approximately 4% to 8%.[20] This range likely results from the heterogeneity of usage within the customer classes. The proposed rate changes include an approximate 20% increase in the customer charge (fixed), 20% increase in the demand charge (for customers over 5 kW), and 10% increase in the volumetric charge. As a result, customers with low usage and/or a low load factor will see the greatest rate increase.[21]

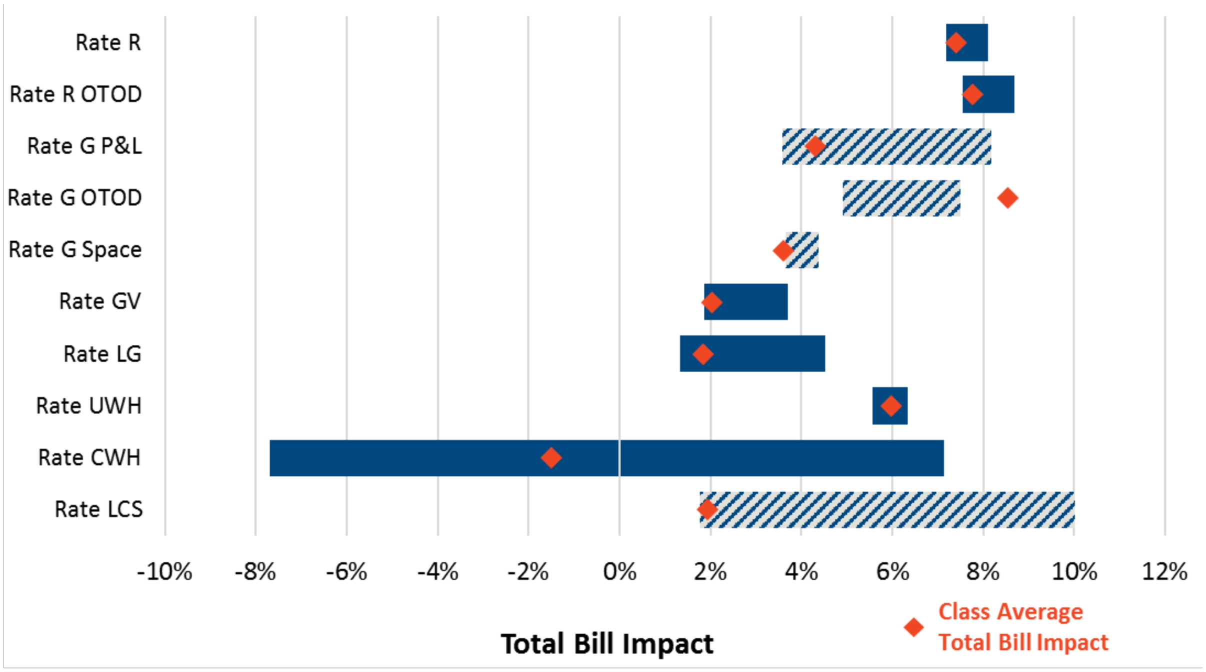
Finally residential customers have relatively low variation in total bills. The impact ranges from an increase of approximately 7% to 8%.

[19] The volumetric component of the proposed rage is \$0.00149/kWh of a total \$0.13088/kWh for Rate G LCS.

[20] Note that this range of impacts relies on the ranges of impact provided by Witness Davis. The actual range of impacts will be wider due to customers not included in the analysis.

[21] Load factor describes the ratio between average and peak demand. A customer with a low load factor has a high peak demand relative to average usage.

Figure 6: Total Bill Impacts



Sources and Notes:

Figure relies on data from Company's updated customer bill impact analysis from Attachment SIS-3 (Data Response Attachment Staff 14-010A) and customer count data from Attachment SIS-2 (Data Response Attachment Staff 14-010 B).

Dashed bars reflect classes where greater than 25% of customers do not have corresponding bill impacts.

Rates UWH in figure captures impact across Rate R UWH and Rate G UWH because the class have the same underlying customer and volumetric distribution charges and changes. Rate CWH similarly captures impact across Rates R CWH and G CWH. Rate LCS captures impact across Rate R LCS Radio Controlled and Rate G LCS Radio Controlled.

Rates G P&L and G OTOD represent range of impacts from respective 1-Phase and 3-Phase customers.

Average impact for Rate CWH just captures average impact of Rate R CWH because there was no average impact provided for Rate G CWH.

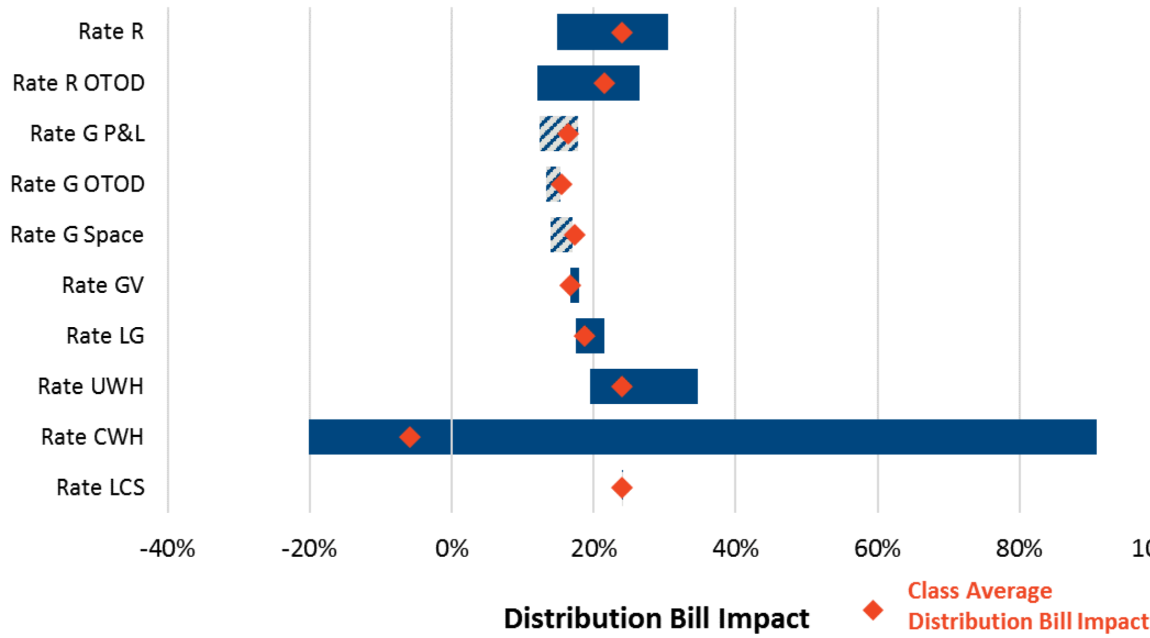
Q. Did you consider the impact of the proposed rate increases on the distribution portion of the bill as well?

A. Yes. While the total bill impact is the "take home" impact that a customer sees immediately, the rate impact on the distribution portion of the bill is also meaningful to consider because it will remain in place regardless of whether energy or transmission prices rise or fall.

As shown in Figure 7 below, the range of distribution impacts is significantly larger for the residential and uncontrolled water heating classes than on a total bill basis. The proposed increases result in a 15% to 30% increase in the distribution portion of the bill for residential customers. This range of 15% to 30% roughly holds for the

Uncontrolled Water Heating (19% to 35%, Rates R UWH and G UWH) and Residential Time of Use class (12% to 26%, Rate R OTOD).

Figure 7: Distribution Portion of the Bill Impact



Sources and Notes:

Figure relies on data from Company's updated customer bill impact analysis from Attachment SIS-3 (Data Response Attachment Staff 14-010A) and customer count data from Attachment SIS-2 (Data Response Attachment Staff 14-010 B).

Dashed bars reflect classes where greater than 25% of customers do not have corresponding bill impacts.

Rates UWH in figure captures impact across Rate R UWH and Rate G UWH because the class have the same underlying customer and volumetric distribution charges and changes. Rate CWH similarly captures impact across Rates R CWH and G CWH. Rate LCS captures impact across Rate R LCS Radio Controlled and Rate G LCS Radio Controlled.

Rates G P&L and G OTOD represent range of impacts from respective 1-Phase and 3-Phase customers.

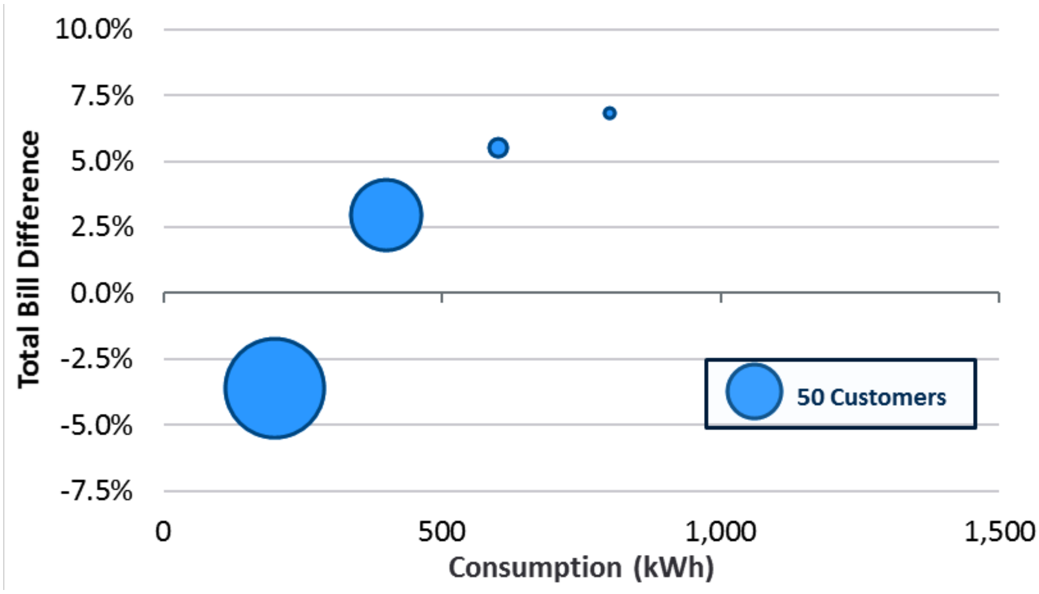
Average impact for Rate CWH just captures average impact of Rate R CWH because there was no average impact provided for Rate G CWH.

Q. Did you conduct an analysis that provides additional context on bill impacts at varying levels of consumption?

A. Yes, for a subset of customer classes (Rate R CWH, Rate R, and Rate G 1-Phase), I replicated Witness Davis's rate impact analysis relative to the current (permanently approved) rates. I selected these rates because they either represented a very large range of potential impacts, or impacted the most amount of customers.

I selected the Controlled Water Heating classes (R CWH and G CWH) because they have the largest ranges of bill impacts on a total bill basis (-8% to 7%). In Figure 8, which shows the total bill impact of the proposed rate increase, the size of the circle indicates the number of customers (with larger circles indicating a greater number of customers). As shown below in Figure 8, customers with lower usage see a reduction in total bill (based on the first phase of the rate change), while customers with higher usage experience bill increases. The greater number of customers with lower consumption and, therefore, total bill reductions explains why the class average total bill impact for Rate CWH is negative in Figure 6.

Figure 8: Residential Controlled Water Heating (Rate R CWH) Total Bill Impacts



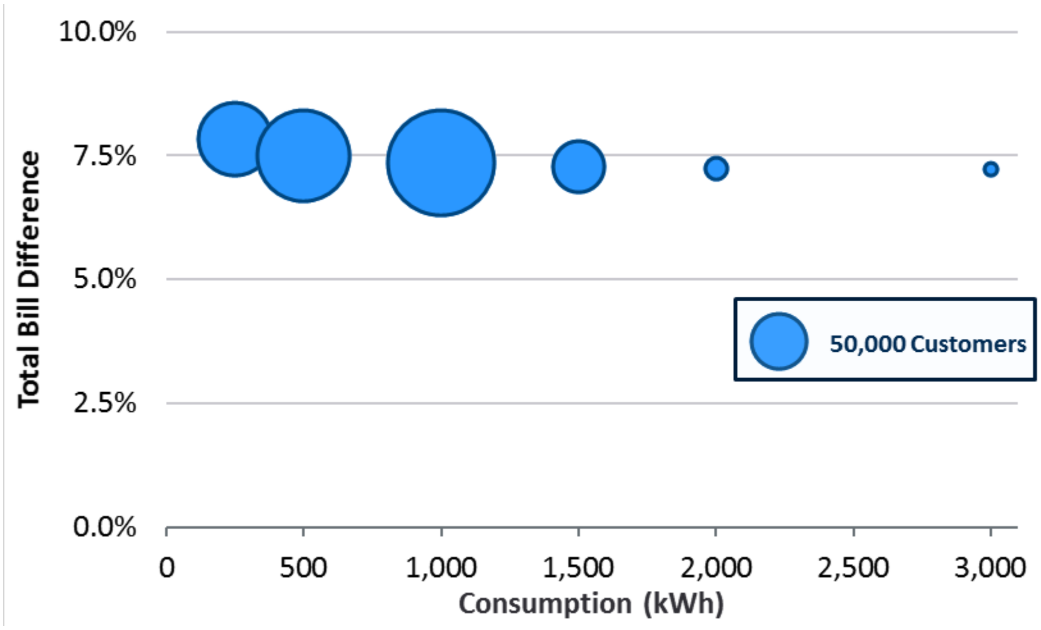
Sources and Notes:

Figure relies on data from Company's updated customer bill impact analysis from Attachment SIS-3 (Data Response Attachment Staff 14-010A) and customer count data from Attachment SIS-2 (Data Response Attachment Staff 14-010 B).

Bubbles located on x-axis according to upper consumption bound (e.g., bubble at 400 kWh represents customers between 201 kWh and 400 kWh consumption, where bill impact is customer weighted across 201-300 and 301-400 customer bins).

The residential (Rate R) total bill impact affects the most customers (445,391 customers). Figure 9 shows the total bill impacts from the proposed rate changes for residential customers. The total bill impact slightly decreases with increasing consumption because the fixed customer charge increases more (9%) than the total volumetric rate (7%).[22]

Figure 9: Residential (Rate R) Total Bill Impacts



Sources and Notes:

Figure relies on data from Company's updated customer bill impact analysis from Attachment SIS-3 (Data Response Attachment Staff 14-010A) and customer count data from Attachment SIS-2 (Data Response Attachment Staff 14-010 B).

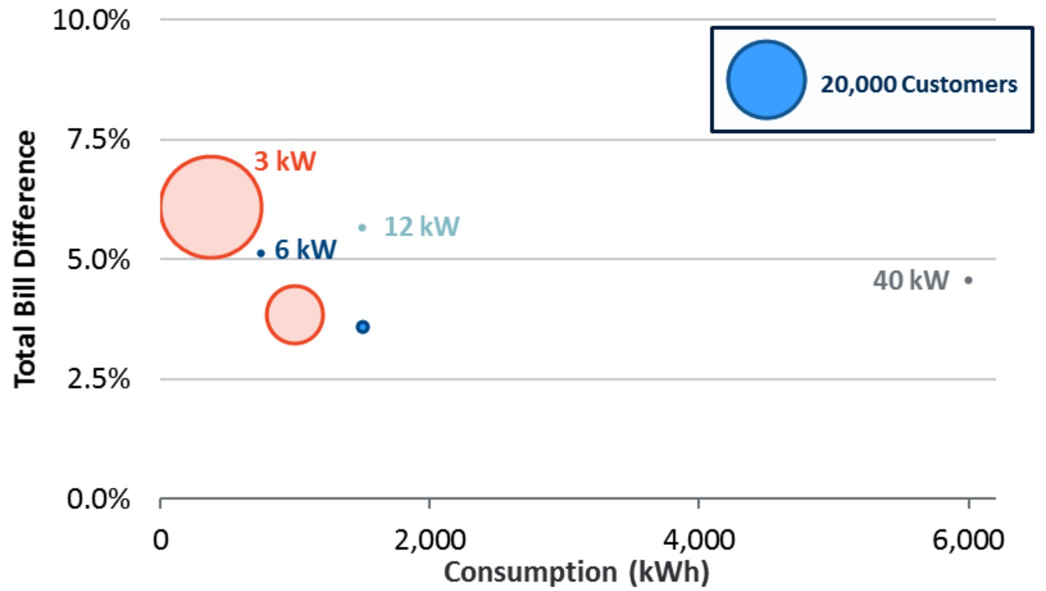
Bubbles located on x-axis according to upper consumption bound ((e.g., bubble at 500 kWh represents customers between 251 kWh and 500 kWh consumption, where bill impact is customer weighted across 251-300, 301-400 and 401-500 customer bins).

For graphing purposes, highest bubble at 3,000 kWh represents customers between 2,001 kWh and 7,500 kWh.

The Rate G 1-Phase class has the greatest number of general service customers. For these general service customers, the rate impact depends both on volumetric and demand charges. In Figure 10, the number of customers in each group are shown by the size of the bubble and the colors indicate the customers' demand levels. All else held equal, customers with lower volumetric usage will see higher rate increases as the fixed and demand charges increased more on a percentage basis than the volumetric charges.

[22] Although the proposed volumetric distribution rate increases 31%, the rest of the other volumetric charges that the customer sees (e.g., transmission and energy) do not change, so the customer only experiences a 7% impact on a total volumetric rate basis.

Figure 10: General Service (Rate G 1-Phase) Total Bill Impacts



Sources and Notes:

Figure relies on data from Company's updated customer bill impact analysis from Attachment SIS-3 (Data Response Attachment Staff 14-010A) and customer count data from Attachment SIS-2 (Data Response Attachment Staff 14-010 B).

Bubbles located on x-axis according to upper consumption bound. Customer with consumption above upper consumption bound for a given level of demand are not included in analysis.

40 kW bubble represents weighted impacts from 30 kW and 40 kW customer buckets.

Q. What are your conclusions based on your analyses of customer bill impacts of Company's proposed rate designs?

A. My analyses indicate that the total bill impacts of the proposed rate designs are generally reasonable for all rate classes, and range from 1% to 10% (excluding Rate R CWH). These results indicate that Company's proposed rate design meets three of the five requirements of the rate design principles outlined at the onset of my testimony. Proposed rates would lead to *bill stability for customers* (given the small total bill impacts); *customer satisfaction* (given the simple structure of the rates) and *Revenue Adequacy and Stability* (given that the ROR approach ends up moving all class revenue allocations closer to the allocated costs).

However, the proposed rate structure may be detrimental to *equity* as it may lead to intra-class subsidies as the penetration of distributed generation increases. This may occur due to the volumetric structure of the proposed rates; DG customers avoid paying for their fair share of the distribution system costs that are mainly recovered through the energy charges under the proposed design.

Also, the proposed rates are not cost-reflective, and therefore do not promote *economic efficiency* as discussed earlier. This is mostly due to the prioritization of bill stability principle by the Company preventing broader updates to the rate design that may improve economic efficiency of the rates. Absence of smart meters for smaller customers is currently a barrier for the Company to developing more cost reflective rates that align the cost structure with the rate structure (i.e., introduction of demand charges to recover capacity related costs of the distribution system, time based rates, etc.)

Q. Are these alternative rate designs being considered in other dockets?

A. Yes, in the alternative net metering docket (DE 16-576), Eversource Energy and Unitil Energy Systems are required to conduct a time of use pilot and Liberty Utilities is working on a real time pricing pilot (See DE 19-033 for Unitil Energy Systems proposal). In addition, alternative rate designs are being considered in the grid modernization docket (IR 15-296).

Q. What are your recommendations regarding the rate design proposed by Eversource?

A. I have four main recommendations:

- The Company should rely on the MCOS study for rate design and move towards more cost reflective rates, which encourage economic efficiency and market-enabled decision making for both operations and new investments, in a technology neutral manner.
- The Company should revise the revenue allocation for the Rate LG for which ROR allocated revenues are substantially different from the MCOS allocated revenues.
- The Company should increase the customer charges further for Rate GV and Rate LG to achieve a better alignment with the MCOS based customer charges.

- The Company should revise the TOU rate design to more closely mirror the time periods and seasonality identified in the MCOS study. Witness Nieto's Option B constitutes a good starting point for the revision of the TOU rate design.
- The Company should try to minimize unintended intra-class subsidies by cost reflective rate design, and analyze costs and benefits of metering infrastructure that would enable these advanced rates for residential customers.

Q. Do you have any comments regarding any existing rate structures?

A. Yes. I recommend elimination of the declining block rate structure in Rates G and GV. Declining block rates do not accurately reflect costs nor do they provide the proper incentive for customers to conserve energy. While I recognize that switching from a declining block rate to a flat rate in these rate classes might have a significant bill impact, such a flat rate could be phased-in to provide for a more gradual rate impact if the impact is determined to be too great.

Q. Did the Company propose a separate rate for electric vehicle (EV) charging stations?

A. No. They did not.

Q. Do you know of other activities in New Hampshire related to electric vehicle rates?

A. Yes. In SB 575, that became effective on August 11, 2018, the Public Utilities Commission ("PUC") must consider and determine whether it is appropriate to implement certain rate designs for electric companies and public service companies for electric vehicle charging. The specific rate design standards for consideration are as follows: 1) cost of service; 2) prohibition of declining block rates; 3) time of day rates; 4) seasonal rates; 5) interruptible rates; 6) load management techniques; and 7) demand charges. This bill also requires the PUC to consider and determine whether it is appropriate to implement "electric vehicle time of day rates" for residential and commercial customers.

Q. Do you believe that the Company should address rates for EV charging stations in this rate case?

A. No. While I believe that a rate case is typically the proper venue for proposing new rates, I recommend that the Company wait to implement electric vehicle charging rates until after the PUC considers and determines the appropriate rate design for implementation across the state.

Q. Does this conclude your testimony?

A. Yes.

Principal

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Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in economic analysis of distributed energy resources (DERs); their impact on the distribution system operations and assessment of emerging utility business models and regulatory frameworks. She regularly assists electric utilities, regulators, law firms, and technology firms on matters related to innovative retail rate design, big data analytics, grid modernization investments, and alternative ratemaking mechanisms.

Dr. Sergici was part of the Brattle team advising the New York Department of Public Service Commissioners and led the development of a financial model to study the incentives required for and the impacts of incorporating large quantities of DERs on utility earnings and rates, during the early stages of the New York Reforming the Energy Vision (NYREV) initiative. Results of this model was instrumental in the development of key regulatory incentive mechanisms in NY. She has assisted several utility clients in developing short term and long term strategies involving new utility business models and regulatory frameworks enabling these models.

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

Dr. Sergici is a frequent presenter on the economic analysis of DERs and regularly publishes in academic and industry journals. She was recently featured in Public Utility Fortnightly Magazine's "Fortnightly Under 40 2019" list. She received her Ph.D. in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her M.A. in Economics from Northeastern University, and B.S. in Economics from Middle East Technical University (METU), Ankara, Turkey. Dr.

AREAS OF EXPERTISE

- Utility Regulatory and Business Models
- Innovative Rate Design and Impact Evaluation Studies
- Distributed Energy Resources
- Grid Modernization
- Resource Planning

EXPERIENCE

Utility Regulatory and Business Models

- Assisted the New York Department of Public Service to develop a comprehensive financial model of a representative (downstate) New York utility capable of demonstrating the impacts of REV initiatives upon utility financial performance. Our modeling effort included developing plausible incentive regulation frameworks, new incentive mechanisms, and potential platform frameworks, services and futures.
- Development of Performance Incentive Metrics for the Joint Utilities of New York. The Brattle Group worked with the New York PSC Staff and, subsequently, with the State's six investor owned electric utilities (Joint Utilities) in analyzing the feasibility and impacts associated with proposed earnings sharing mechanisms (EAMs), primarily the EAMs associated with load factor and system efficiency.
- Assisted a North American Utility with development of a short-term and long-term regulatory strategy to enable their 2030 Vision. Brattle team interviewed the executive team; identified consensus views and disagreements on alternative business models and regulatory models. Developed straw proposals for two potential regulatory models one focused on enabling shorter-term outcomes, and the other focused on enabling Company's longer-term vision.
- Assisted Pepco D.C. as they develop a multi-year rate plan and various traditional and emerging performance incentive metrics to be filed in their upcoming rate case. Brattle team developed and facilitated workshops to introduce Pepco's MYRP proposal to the stakeholders and assisted Pepco with incorporating stakeholder input to the final proposal.
- Assisted a Canadian Utility with a critical assessment of their custom incentive ratemaking model and discussed how it compares with other forms of PBR. We presented a jurisdictional scan of the PBR implementations across North America and Europe, and assessed pros and cons of each approach. We also advised them on currently proposed "Distributed Utility Models" and assess pros and cons of each model; reviewed "Alternative Regulatory Models" that were developed to ensure that utilities can coexist with the DERs and continue to maintain healthy balance sheets.

- For a Canadian electric utility, reviewed and summarized alternative regulatory frameworks and incentive models that would support a sustainable energy efficiency business. Investigated the pros and cons of these models, identified the implications of each model for the utility, and made a recommendation based on our findings. Utility will discuss the recommended approach with the regulator and seek an approval.
- For a large Canadian electric utility, assisted with the development of an alternative proposal to their current performance based regulation (PBR) framework. Examined and benchmarked several examples of performance based regulation schemes in place for other utilities, and advised on an enhanced PBR mechanism.

Innovative Rate Design and Impact Evaluation Studies

- Design, measurement and verification of Maryland Joint Utilities' PC44 TOU pilot. Brattle serves as the technical lead on behalf of the Maryland Joint Utilities, and led the pilot design and M&V methodology work streams in the PC44 workgroup process. Brattle will evaluate results from these three pilots in 2020.
- Assisted a New Zealand distribution utility with development of a peak time rebate pilot. Advised the client in pilot design principles and calculated sample sizes to yield statistically significant results. Undertook empirical testing of more than 150 different baseline methods using the client data and recommended an approach that leads to the highest accuracy and lowest bias in predicting the event day usage.
- Developed a model for the Ontario Energy Board to estimate a counterfactual hourly customer demand profile for multiple innovative pricing profiles of interest. Evaluated the economic efficiency of each alternative pricing option, taking into account system cost drivers including energy, ancillary services, generation capacity, and transmission and distribution capacity, as well as overall changes to consumer welfare driven by induced changes in demand. This represents one of few efforts to fully quantify the societal costs and benefits of innovative rate structures and involved close collaboration with the OEB team to ensure the Ontario-specific market structures were accurately reflected in our analysis.
- Technical Advisor to OEB on the New RPP Pilots. A Brattle team led by Dr. Sergici has developed a Technical Manual to guide the design and impact evaluation of new RPP pilots. Dr. Sergici has been closely working with the OEB RPP team as they oversee the implementation of these pilots in accordance with the guidelines

- Undertook impact Evaluation of Ontario's Time-of-Use Rates on Behalf of Ontario Power Authority. A Brattle team led by Dr. Sergici provided an impact evaluation of Ontario's province-wide roll-out of Time-of-Use (TOU) rates for its residential and general service customers on behalf of Ontario Power Authority. Brattle acquired hourly load data from the IESO and the LDCs, aggregated it for the pricing periods that correspond to the TOU rate, reinterpreted the full-scale deployment as a natural experiment, and analyzed it using econometric methods for three consecutive years.

- Undertook an extensive review of the rate designs and methodologies used by other jurisdictions/countries for a large Canadian Utility. We reviewed the rates that are currently offered by a large Canadian utility and compared them with best industry practices from around the globe. As a result of our analysis, we identify some near term and long term alternative rate design options for our client, which can help them to manage revenue risks and volatility due to the effects of disruptive threats, and at the same time to increase innovation and affordability in the rate options presented to the customers.

- Assisted Pepco Holdings, Inc. to evaluate the effectiveness of the AMI-enabled energy managements tools (EMTs) in reducing per capita energy use. Led a team of four researchers to compile and process data for four of the PHI jurisdictions; identify relevant control groups and methodology for impact evaluation and undertake an econometric analysis to quantify the EMT impact.

- Assisted an industry-leading provider of integrated demand response, energy efficiency, and customer engagement solutions in the design of and M&V plan for a behavioral demand response program. The plan included a detailed section on sampling selection for statistically valid and detectable program impact results.

- Prepared a comprehensive blueprint document for measuring the impacts of Baltimore Gas and Electric Company's Smart Grid Customer Programs. BGE has started deploying smart meters to all of its residential customers in Spring of 2012 and is scheduled to complete the deployment over a three-year period. BGE developed a full-scale program, "Smart Energy Manager (SEM)" program, to meet a central objective of the Smart Grid Initiative - customer education and engagement in a Smart Grid environment. The blueprint documented the design elements of the SEM program and introducing the approaches that will be used to measure the impacts of different SEM tools once the program is in the field and sufficient data are collected.

- Measurement and evaluation for in-home displays, home energy controllers, smart appliances and alternative rates for FPL. Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.
- Pricing and technology pilot design and interim impact evaluation for Commonwealth Edison Company (ComEd). Assisted ComEd in the design of an ambitious pilot program that included approximately 25 different treatment cells. The pilot, which is the first "opt-out" pilot program of its kind, involved 8,000 customers and tested the impact of dynamic prices with and without customer education, informational feedback through basic and advanced feedback devices, and other enabling technologies in the summer of 2010. Conducted an interim impact evaluation study preceding the formal impact evaluation of the study, which is planned to be completed by the end of 2011.
- Pricing and technology pilot design and impact evaluation for Consumers Energy. Designed Consumers Energy's pricing and technology pilot and conducted the impact evaluation study after the pilot was completed in September 2010. The pilot tested critical peak pricing (CPP) and peak time rebates (PTR) in conjunction with information treatment and technology. The pilot also tested the potential "Hawthorne bias" for a group of control group customers who were aware of their involvement in the pilot.
- Member of a Technical Advisory Group (TAG), which was formed by Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL). Reviewed and provided feedback on the experimental designs of the utilities that were awarded Smart Grid Investment Grant projects and participated in periodic project review meetings with utilities to review and provide feedback on the interim results as they implement their projects. As part of this assignment, authored a guidance document that discussed different impact evaluation methods, which can be selected by the utilities. This document was shared with the utilities and other TAG members.
- For an Independent System Operator (ISO), designed, managed and analyzed a market research to help improve participation in retail electricity products that encourage price-responsive demand (PRD). The research determined customer preferences for various time-based pricing products that would help define PRD products that may be developed

in the ISO for each customer class. ISO will use the results of this research to assist in modifying wholesale market design to better support such PRD products.

- Assisted a client in conceptually developing a new product that would increase customer participation and performance in energy efficiency (EE) and demand response (DR) programs. Developed Total Resource Cost (TRC) tests for a few targeted EE and DR programs, and modeled the benefits and costs with and without the client's new product offering
- Co-authored a whitepaper reviewing the results from five recent pilot and full-scale programs that investigated low-income customer price-responsiveness to dynamic prices. The core finding of the whitepaper is that low income customers are responsive to dynamic rates and that many such customers can benefit even without shifting load.
- For a large California utility, conducted an econometric analysis, which investigated the role of weather conditions, smart meter installations, and electricity rate increases, among other control variables, in explaining the changes in the monthly usages and bills of a group of complaining customers. Estimated pooled regressions using a panel dataset, as well as individual customer regressions for more than 1,000 customers.
- Assisted an Illinois electric utility in the assessment of alternative baseline calculation for implementing peak time rebate (PTR) programs. Under a PTR program, participants receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours. This requires establishment of a baseline load from which the reductions can be computed. The analysis involved simulating baselines for more than 2,000 customers using five alternative methodologies for several event days. Identified and recommended the baseline calculation methodology that yielded the most accurate baseline for individual customers, through the use of MAPE and RMSE statistics.
- Evaluated the Plan-It Wise Energy program (PWEP) of Connecticut Light and Power (CL&P) Company. PWEP tested the impacts of critical peak pricing (CPP), peak time rebates (PTR), and time of use (TOU) rates on the consumption behaviors of residential and small commercial customers. Each rate design was tested with high and low price variation as well as with and without enabling technologies. Conducted an econometric analysis to determine weather dependent substitution and daily price elasticities and subsequently quantified demand and energy impacts for each of the treatments tested in the PWEP. Developed optimal rate designs to be adopted in a full deployment scenario.

- For Baltimore Gas and Electric Company, assisted in the preparation of direct and rebuttal expert testimonies before the Maryland Public Service Commission, that explain the design and results of 2008 and 2009 Smart Energy Pricing (SEP) pilots.
- Evaluated the Smart Energy Pricing (SEP) pilot program of Baltimore Gas and Electric Company for three consecutive years. The pilot was designed to quantify the impacts of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. Conducted an econometric analysis to estimate demand systems and predict substitution and daily price elasticities for participating customers. Using the parameters of the demand equations, quantified demand, energy, and bill impacts associated with the programs. Impacts of the socio-demographic characteristics of the participants as well as their ownership of enabling technologies were separately identified on the demand response of the program participants.
- Co-authored a business practice manual for forecasting price responsive demand (PRD) in Midwest ISO. The draft manual introduces different methodologies for measuring and incorporating PRD into forecast LSE requirement for LSEs that are at different stages of rolling-out their out their dynamic pricing programs. The draft manual also proposes methodologies for the verification of the forecasted demand net of PRD for long term planning purposes.
- Assisted in the development of an affidavit that evaluates the implications of PJM's proposed revisions to the Operating Agreement (OA) on barriers to participation in PJM's Economic and Emergency Load Response programs.
- Co-authored a whitepaper on "Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets" for Institute for Electric Efficiency. Whitepaper is intended to help facilitate nationwide progress toward the deployment of dynamic pricing of electricity by summarizing information that may assist utilities and regulators who are assessing the business case for advanced metering infrastructure (AMI).
- Assisted a New York utility in benchmarking their existing Demand Response (DR) portfolio to the best practice in U.S. and recommended improvements in their planned DR portfolio. Also assisted the utility in quantifying costs and benefits of pilot programs proposed in their DR filing before the State of New York Public Service Commission.
- Assisted an electric utility in developing a residential pricing pilot program that tests inclining- block rate (IBR) structure. More specifically, designed several revenue neutral

IBR alternatives and quantified load reduction and bill impacts from these IBR rates.

- Assisted an electric utility in their dynamic rate design efforts. Conducted impact analyses of converting from a flat rate design to alternative dynamic rate designs for each of the five major customer rate classes of the utility. Developed models that allow simulation of energy, demand, and bill impacts by season, day type and time period for an average customer from each of customer classes.
- Simulated the potential demand response of an Illinois utility's residential customers enrolled in real time prices. Results of this simulation were used in recent Midwest ISO Supply Adequacy Working Group (SAWG) meeting to facilitate conversation about price responsive demand in the region. Simulations were run for different scenarios including historic versus spiky real-time prices; peak versus uniform allocation of capacity charges; and with and without enabling technologies.
- Designed a survey on Long-run Drivers of U.S. Energy Efficiency and Demand Response Potential on behalf of EPRI and EEI. Conducted statistical analyses to examine the survey responses, which were turned in by more than 300 power industry leaders and academic experts. Using the outcomes from this survey, assisted in the development of future scenarios to model energy efficiency and demand response impact through 2030.
- Assisted in the preparation of an EEI report that quantifies the benefits to consumers and utilities of dynamic pricing. Undertook a comprehensive review of the dynamic pricing programs across the U.S. and elsewhere. Also implemented price response simulations to quantify the likely peak demand reductions that would realize under alternative dynamic pricing schemes.

Distributed Energy Resources and Grid Modernization

- System Dynamics Modeling of DER Adoption and Utility Business Impacts. Led the development of Brattle's Corporate Risk Integrated Strategy Platform (CRISP) model and assisted utility clients with the implementation of this model. CRISP is based on System Dynamics approach, which creates simulations based on dynamic feedbacks between utility policies and customer behavior, providing a new perspective on how much and how fast the "utility of the future" must evolve. The focus of these modeling efforts was to help utilities anticipate and accommodate distributed energy resources (DERs) as they become more economical and more widely adapted by retail electricity customers, and to evaluate the sustainability of their traditional cost-of-service business model in the face of such trends.

- Co-led a study for EPRI that analyzed a variety of approaches to representing DERs in utility planning models. Started with energy efficiency as the first DER to be analyzed, and undertook a comprehensive literature review to capture the complete range of options for evaluating EE in IRPs. Next, quantitatively evaluated the impact of the EE modeling method on important IRP objectives such as minimizing total resource costs, meeting environmental goals, and avoiding suboptimal resource planning decisions.
- Estimated NEM cross-subsidies using data from sixteen utilities. Used cost-of-service methodology to compare NEM customers costs on the system vs. revenue collection from these customers using company COS studies, and supplementing it by publicly available data on solar PV production profiles, installed DG capacity by utility and system load profiles.
- Wrote a comprehensive report for National Electrical Manufacturer's Association (NEMA) that reviews most recently approved 10 major grid modernization projects. Report discusses business cases and cost recovery mechanisms for each of these projects and documents how grid modernization technologies have benefitted customers and utilities.
- Analyzed the impacts of electric utility infrastructure investment on system reliability and resiliency for a Northeastern Utility, following major weather events. Primary area of analysis involved estimation of economic value of investments to customers using value of lost load (VOLL) metrics for electric system investments.
- Assisted Pepco Holdings, Inc. to analyze the Phase I of its Conservation Voltage Reduction (CVR) program in its Maryland Service Territory. First of its kind, this econometric study compares consumption of the treatment and control groups before and after the implementation of CVR. More specifically, a regression analysis was conducted to compare the usage levels of treatment and control group customers to determine whether the CVR treatment resulted in statistically significant conservation and peak demand impacts. The analysis accounts for exogenous factors such as weather, calendar and seasonality impacts as well as utility energy and demand savings programs.

Resource Planning

- Led the Brattle team that assisted the New York City Mayor's Office of Sustainability with the development of New York City's Roadmap to 80 x 50. The Brattle team analyzed the change in energy-sector greenhouse gas (GHG) emissions resulting from more than six future scenarios. These scenarios explored the impacts of aggressive energy efficiency efforts, off-shore wind, and the continuance of low natural gas prices on the emissions footprint of New York City. The analysis shows that in order to reach 80 x 50, New York City will need to achieve a significant portion of its GHG reductions as a result of a dramatic shift towards a renewables-based grid. This shift towards renewables must overcome the anticipated retirement of nuclear facilities prior to 2050 and will be supported by the implementation of New York State's Clean Energy Standard and the declining cost of renewable energy.

- Conducted a study involving "solar to solar" comparison of equal amounts of residential- and utility-scale PV solar deployed in Xcel Energy Colorado's Service Area. Calculated costs and benefits of each of these two different but equally sized solar options, i.e., avoided energy, capacity and distribution network costs and others. The study found carbon reductions were greater on utility scale systems because the solar energy per MW is much higher on utility-scale due to better placement and tracking capability.
- Advised Nova Scotia Power Inc. on the reasonableness of the DSM scenarios and strategies that are being modeled in their Integrated Resource Plan (IRP). This effort also involved advising the Company on a variety of DSM issues and building up a model that quantifies the rate impacts for program participants and non-participants based on the selected DSM scenario.
- Coauthored the State's Annual Integrated Resource Plan (IRP) for the Connecticut Department of Energy and Environmental Protection (DEEP). This effort involved development of scenarios and strategies for an electric system to meet long-range electric demand while considering the growth of renewable energy, energy efficiency, other demand-side resources. Led the development of demand side management and emerging technology resource strategies and analyses involving these resources.
- Developed a model to assess the prudence of an electric utility's power procurement strategy in comparison to several other alternative options. As a result of this model, she assessed whether it is prudent to recover the congestion and loss costs associated with utility's chosen strategy from ratepayers in a state regulatory proceeding.
- Assisted in preparation of a marginal cost study for an integrated electric utility. The study estimated the incremental costs to the utility of serving additional demand and customer by time period, sub-region, and customer class. The costs were identified as energy, capacity and customer related for generation, transmission, and distribution

systems of the utility.

- Assisted in developing an integrated resource plan for major electric utilities. Contributed to the design of future scenarios against which the resource solutions were evaluated. Designed scenarios were driven by external factors including fuel prices, load growth, generation technology capital costs, and changes in environmental regulations. Forecasted the inputs series for the resource planning model consistent with each of the designed scenarios.

Demand Forecasting

- For an Asian utility considering an investment on a generation plant in PJM, we have reviewed, replicated, and developed alternative load forecasts using PJM's 2017 update. We have determined several uncertainty factors that are not fully captured in PJM's forecasting framework and developed "low load" and "high load" scenarios after accounting for these factors.
- For an electric utility in the Southeast, reviewed load forecasting models for residential and commercial customer classes. Assessed the accuracy and validity of the models by reviewing the historic and forecast period inputs to the model; model specification; in-sample and out-of- sample accuracy statistics; and incorporation of DSM impacts to the model, among many others. Also conducted an analysis using the U.S. Energy Information Administration's Annual Energy Outlook (AEO) data to determine the forecast errors during pre and post-recession periods.
- Developed a blueprint for integrating energy efficiency program impacts into the load forecasts for a Canadian Utility. This effort involved estimating the future impact of energy efficiency programs to be included in the load forecasts and developing price elasticity estimates that can be used to forecast the impact of the future changes in the price of electricity.
- Developed a load forecasting model for the pumping load of California State Water Project. Identified the main drivers of pumping load in major pumping stations. Through Monte Carlo simulations, quantified the uncertainty around load forecasts.
- Assisted in the preparation of testimony that evaluates the reasonableness of Florida Power and Light Co.'s total customer and monthly net energy for load (NEL) forecasting models. In addition to evaluating the methodology, also reviewed the reasonableness of the inputs used in the historic and forecast periods and assessed the soundness of ex-post

adjustments made to the forecasts.

- Assisted PJM in the evaluation of its models for forecasting peak demand and re-estimated new models to validate recommendations. Predicted forecasting errors of the existing models and helped improving the forecast methodology by introducing the state-of-the art estimation techniques. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.
- Assisted a large utility in New York in understanding the decline in electric sales during the recent past and attributed the decline to a change in customer expectations of future income, based on declining consumer confidence that has been created by the lingering economic recession.
- Reviewed the structure of the Tennessee Valley Authority's energy sales forecasting models by sector, assessed the magnitudes of the price elasticities and the model specifications used to generate them, analyzed the ability of the models to generate a baseline forecast that could serve as a point of reference when evaluating the likely impacts and cost-effectiveness of a wide range of new energy efficiency and demand response programs.
- Developed a demand forecast model for one of the world's largest steam system operators. Estimated regression models to predict the price elasticities and switching behavior of different consumer classes. Also helped in the development of a model to forecast the impact of alternative steam tariffs on the consumption and switching patterns of consumers.

Energy Litigation and Market Power Analysis

- For the California Parties, provided Brattle witness with litigation support and testimony regarding manipulation of electric power and natural gas prices in the western U.S. during 2000-
01. The proceeding, before the Federal Energy Regulatory Commission involved Enron, Dynegy, Mirant, Reliant, Williams, Powerex and many other suppliers in the U.S. and Canada.
- Part of a Brattle team that analyzed the impacts of a merger, involving FirstEnergy and West Penn Power, on competition in retail electricity markets on behalf of Brattle testifying expert Mr. Frank Graves. Both companies owned electric distribution companies, transmission assets, generation resources, and retail electricity providers in

several Mid-Atlantic States. The analysis involved assessment of whether the increased market share in wholesale energy markets affects retail competition, the number of suppliers in retail electricity markets, the ease of entry and exit to provide electricity to retail customers directly or through default service procurements, and the potential for abusing affiliate relationships with the electric distribution company to favor the retail electricity provider affiliate.

- Assisted in preparing affidavit before the Federal Energy Regulatory Commission examining whether the proposed acquisition of a power plant by an electric utility would lead to anti-

  competitive effects on wholesale market competition. In addition to performing market power tests required by FERC, directed an analysis that investigates the historical electric trading patterns between the acquiring utility and the other parties in the relevant geographical market. FERC agreed with the conclusion of the affidavit and authorized the transaction.

- Assisted in the development of testimony before the Postal Rate Commission involving calculation of mail processing variabilities and data quality issues. Addressed the endogeneity problems in the estimation of the variabilities using the instrumental variables approach.

OTHER PROFESSIONAL EXPERIENCE

- Taught Microeconomics for one year at Northeastern University. Also worked as a Research Assistant to Prof John Kwoka of Northeastern University on different utility industry projects.
- Worked as an adjunct research assistant for American Public Power Association and conducted an extensive literature survey on 'Time-of-Use (TOU) Pricing in Electric Utility Industry.

ACADEMIC HONORS AND FELLOWSHIPS

- Excellence in Economics Award, Northeastern University, 2008
- Member, The Honor Society of Phi Kappa Phi
- Graduate Fellowship & Tuition Scholarship, Northeastern University, 2003-2007

- Tuition scholarship and stipend from the Turkish Ministry of Education towards the completion of B.S. Degree in Economics, 1999-2003
- Turkish Government Scholarship Examination, ranked 1st among 600,000 students in 1995

TECHNICAL AND EXPERT REPORTS

1. *Incorporating Distributed Energy Resources into Resource Planning: Energy Efficiency*, with Ryan Hledik, D.L. Oates, Tony Lee, and Jill Moraski, prepared for EPRI, May 2019.
2. *Status of DSM Cost Recovery and Incentive Mechanisms,* with Ahmad Faruqui, Elaine Cunha, and John Higham, prepared for Baltimore Gas & Electric, February 20, 2019.
3. *U.S. Alternative Regulatory Mechanisms: Scope, Status and Future,* with William Zarakas and Pearl Donohoo-Vallett, prepared for Baltimore Gas & Electric, Delmarva Power & Light and Pepco, February 19, 2019.
4. *A Review of Pay for Performance (P4P) Programs and M&V 2.0*, with Heidi Bishop and Ahmad Faruqui, prepared for Commonwealth Edison, July 20, 2018.
5. *Reviewing the Business Case and Cost Recovery for Grid Modernization Investments,* with Michelle Li and Rebecca Carroll, prepared for National Electrical Manufacturers Association (NEM), 2018.
6. *Pepco Maryland In-Home Display Pilot Analysis*, with Ahmad Faruqui, prepared for Pepco, June 2017.
7. *80x50 Energy Sector Model Assumptions and Results,* with Michael Kline and Pearl Donohoo-Vallett, prepared for the Mayor's Office of Sustainability, January 4, 2017.
8. *Impact Evaluation of Pepco District of Columbia's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco District of Columbia, October 2016.
9. *Impact Evaluation of Delmarva Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Delmarva Maryland, April 2016.
10. *Impact Evaluation of Pepco Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland, January 2016.
11. *Impact Evaluation of Pepco Maryland's Phase I Conservation Voltage Reduction (CVR) Program,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland, July 2015.
12. *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study,* with Neil Lessem,

Ahmad Faruqui, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Independent Electric System Operator, February 2016.
http://www.ieso.ca/Documents/reports/Final-Analysis-of- Ontarios-Full-Scale-Roll-Out-of-TOU-Rates.pdf

13. *Comparative Generation Costs of Utility-Scale and Residential Scale PV in Xcel Energy Colorado's Service Area,* with Bruce Tsuchida, Bob Mudge, Will Gorman, Peter Fox-Penner and Jens Schoene (EnernNex), prepared for First Solar, July 2015.

14. *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast,* with Ahmad Faruqui and Kathleen Spees, prepared for The Sustainable FERC Project, September 2014.

15. *Assessment of Load Factor as a System Efficiency Earning Adjustment Mechanism*, with William Zarakas, Kevin Arritt, and David Kwok, prepared for The Joint Utilities of New York, February 2017.

16. *Expert Declaration in a Patent Dispute Case involving a Demand Response Product,* July 2014. San Francisco.

17. *Measurement and Verification Principles for Behavior-Based Efficiency Programs, with Ahmad Faruqui, prepared for Opower,* May 2011.
http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf

18. *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets,* with Ahmad Faruqui and Lisa Wood, IEE Whitepaper, June 2009.
19. *"The Impact of Dynamic Pricing on Low Income Customers,"* with Ahmad Faruqui and Jennifer Palmer, IEE Whitepaper, June 2010.

PUBLICATIONS

1. "Quantifying Net Energy Metering Subsidies," with Yingxia Yang, Maria Castaner, and Ahmad Faruqui, *The Electricity Journal*, forthcoming.

2. "Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity," with Ahmad Faruqui and Cody Warner, *The Electricity Journal*, Volume 30, Issue 10, December 2017.

3. "Do Manufacturing Firms Relocate in Response to Rising Electric Rates?" with Ahmad Faruqui, *Energy Regulation Quarterly*, Volume 5, Issue 2, June 2017.

4. "Dynamic Pricing Works in a Hot, Humid Climate," with Ahmad Faruqui and Neil Lessem, *Public Utilities Fortnightly*, May 2017.

5. "The impact of AMI-enabled conservation voltage reduction on energy consumption and peak demand," with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:2, March

2017, pp. 60-65. http://www.sciencedirect.com/science/article/pii/S1040619016302536

6. "Integration of residential PV and its implications for current and future residential electricity demand in the United States," with Derya Eryilmaz, *The Electricity Journal*, 29 (2016) 41-52.

7. "Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, *Energy Economics*, 52, December 2015, pp. 39-48.

8. "Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment," by William Zarakas, Sanem Sergici et al., *The Electricity Journal*, Volume 27, Issue 5, June 2014.

9. "Low Voltage Resiliency Insurance: Ensuring Critical Service Continuity during Major Power Outages," by William Zarakas, Frank Graves and Sanem Sergici, *Public Utilities Fortnightly*, September 2013.

10. "Arcturus: International Evidence on Dynamic Pricing," by Sanem Sergici and Ahmad Faruqui, *The Electricity Journal*, 26:7, August/September 2013, pp. 55-65.

11. "Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan," by Ahmad Faruqui, Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, August 2013, pp. 571–584.
12. "Dynamic Pricing of Electricity in the Mid-Atlantic Region: Econometric Results from the Baltimore Gas and Electric Company Experiment," by A. Faruqui and S. Sergici, *Journal of Regulatory Economics*, 27(3), 235–262.

13. "The Untold Story of: A Survey of C&I Dynamic Pricing Pilot Studies," with Ahmad Faruqui and Jenny Palmer, *Metering International*, Issue 3, 2010.

14. Divestiture policy and operating efficiency in U.S. electric power distribution," by John E. Kwoka, Jr., Michael Pollitt, and Sanem Sergici, *Journal of Regulatory Economics*, June 2010.

15. "Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence," with Ahmad Faruqui, *Journal of Regulatory Economics*, October 2010.

16. "Rethinking Prices," with Ahmad Faruqui and Ryan Hledik, *Public Utilities Fortnightly*, January 2010.

17. "Piloting the Smart Grid," with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal*, August/September 2009.

18. "The Impact of Informational Feedback on Energy Consumption - A Survey of the Experimental Evidence," with Ahmad Faruqui and Ahmed Sharif, *Energy-The International*

Journal, August 2009.

19. "Three Essays on U.S. Electricity Restructuring," Unpublished Ph.D. Thesis, Northeastern University, August 2008.

PRESENTATIONS

1. "Rate Reform in Evolving Energy Marketplace," presented at EUCI Residential Demand Charges/TOU Summit, May 30, 2019.

2. "Grid Modernization: Policy, Market Trends and Directions Forward," presented at the 4th Annual Grid Modernization Forum, Chicago, IL, May 21, 2019.

3. "Accelerating the Renewable Energy Transformation: Role of Green Power Tariffs and Blockchain," presented to EUCI Southeast Clean Power Summit, February 25, 2019.

4. "The Case for Alternative Regulation and Unintended Consequences of Net Energy Metering," presented to the 46th Annual PURC Conference, Gainesville, FL, February 21, 2019

5. "Reviewing Grid Modernization Investments: Summary of Recent Methods and Projects," presented to the National Electrical Manufacturers Association (NEMA), December 4, 2018.

6. "Enabling Grid Modernization Through Alternative Rates and Alternative Regulation," presented at the Energy Policy Roundtable in the PJM Footprint, November 29, 2018.

7. "Return of Pay-for-Performance Stronger with M&V 2.0," prepared for BECC Conference, Innovations in Models, Metrics, and Customer Choice, Washington DC, October 2018.

8. "Rate Design in a High DER Environment," presented at MEDSIS Rate Design Workshop, Washington DC, September 2018.

9. "Demand Response for Natural Gas Distribution," presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, Monterey CA, June 2018.

10. "Status of Restructuring: Wholesale and Retail Markets," presented at the National Conference of State Legislatures Workshop, "Electricity Markets and State Challenges," Indianapolis IN, June 2018.

11. "Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida," presented at the International Energy Policy & Programme Evaluation Conference, Bangkok Thailand, November 2017.

12. "Understanding Residential Customer Response to Demand Charges: Present and Future,"

presented at the EUCI Residential Demand Charges Conference, Chicago IL, October 2016.

13. "Utility Leaders Workshop: An Evolving Utility Business Model for the Caribbean," presented at the Caribbean Renewable Energy Forum, Miami FL, October 2016.

14. "Impact of Residential PV Penetration on Load Growth Expectations," presented at the AEIC Western Load Research Conference, September 2016.

15. "Moving away from Flat Rates," presented to Smart Grid Consumer Collaborative, Chicago, IL, September 2016.

16. "Residential Demand Charges: An Overview," presented at the EUCI Demand Charge Conference, Phoenix AZ, June 2016.

17. "Conservation Voltage Reduction Econometric Impact Analysis," presented at the AESP Spring Conference, Washington DC., May 2016.

18. "Caribbean Utility 2.0 Workshop- Economics, Tariffs and Implementation: The Challenge of Integrating Renewable Resources and After Engineering Solutions," co-hosted and presented at the Caribbean Renewable Energy Forum, Miami FL, October 2015.

19. "Dispelling Common Residential DR Myths," presented at the eSource Conference, October 2015.

20. "Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities," presented at NYU School Law's Forum on New York REV and the Role of Time Varying Pricing, March 2015.

21. "Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments," presented at the EDF Demand Response Workshop, Paris, France; July 2014 and Governors Association's Michigan Retreat on Peak Shaving to Reduce Wasted Energy, August 2014.

22. "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," presented at 2014 Smart Grid Virtual Summit, Boston, June 2014.

23. "Residential Demand Response Opportunities," presented at Opower Webinar Series, Boston, June 2014.

24. "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," presented at 33rd Annual Eastern CRRI Conference, May 2014.

25. "The Arc of Price Responsiveness—Consistency of Results Across Time-Varying Pricing Studies," presented at the Chartwell Webinar, Boston, May 2013.

26. "Evaluation of Baltimore Gas and Electric Company's Smart Energy Pricing Program,"

presented at 9th International Industrial Organization Conference, Boston, MA, April 2011.

27. “Dynamic Pricing: What Have We Learned?” presented at the Electricity Markets Initiative Conference, Harrisburg, PA, April 2011.

28. “Do Smart Rates Short Change Customers,” presented at the Demand Resource Coordinating Committee Webinar, December 2010.

29. “Opening Remarks and Session Chair of Day 1,” at the FRA Conference on Customer Engagement in a Smart Grid World, San Francisco, CA, December 2010.

30. “The Impact of Informational Feedback on Energy Consumption,” presented at the 2010 National Town Meeting on Demand Response and Smart Grid, June 2010.

31. “The Impact of In-Home Displays on Energy Consumption,” presented before the Colorado Public Service Commission, June 2010.

32. “Does Dynamic Pricing Work in the Mid-Atlantic Region: Econometric Analysis of Experimental Data,” presented at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference, May 2010.

33. “Distributed Generation in a Smart Grid Environment,” panel speaker at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference, May 2010.

34. “Power of Information Feedback: A Survey of Experimental Evidence,” presented at the Peak Load Management Alliance (PLMA) Webinar, April 2010.

35. “Customer Response to Dynamic Pricing - A Long Term Vision,” presented at 2009 NASUCA Mid- Year Meeting, Boston, June 2009.

36. “BGE’s Smart Energy Pricing Pilot Summer 2008 Impact Evaluation,” presented at Association of Edison Illuminating Companies (AECI) Conference, Florida, May 2009

37. "California and Maryland - Are They Poles Apart?," presented at the Western Load Research Association Conference, Atlanta, March 2009.

38. “Experimental Design Considerations in Evaluating the Smart Grid," presented at the Smart Grid Information Session Massachusetts DPU, December, 2008.

39. “Divestiture, Vertical Integration, and Efficiency: An Exploratory Analysis of Electric Power Distribution,” presented at the 4th International Industrial Organization Conference, Boston, Massachusetts, 2006.

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2018 Customer Counts by Usage

Residential Service - Rate R

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	24,829
101-200	36,812
201-250	23,009
251-300	25,019
301-400	53,392
401-500	54,103
501-600	49,664
601-700	42,268
701-750	18,114
751-1000	61,837
1001-1500	42,981
1501-2000	9,582
2001-2500	2,402
2501-3000	734
3001-5000	530
5001-7500	83
>7500	32

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2018 Customer Counts by Usage

Residential Service - Uncontrolled Water Heating

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	12,143
101-200	15,346
201-300	9,753
301-400	3,944
401-500	1,386
501-600	418
601-700	171
701-800	68
>800	75

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2018 Customer Counts by Usage

Residential Service - Controlled Water Heating

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	66
101-200	92
201-300	58
301-400	25
401-500	5
501-600	2
601-700	2
701-800	1

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2018 Customer Counts by Usage

Residential Service - Optional Time of Day

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	2
101-200	1
251-300	1
301-400	2
401-500	4
501-600	3
601-700	3
701-750	2
751-1000	10
1001-1500	8
1501-2000	4
2001-2500	1
2501-3000	1
7,500	-

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2018 Customer Counts by Usage

Residential Load Control Service - Radio Controlled

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	135
101-200	166
201-300	226
301-400	282
401-500	270
501-600	285
601-700	258
701-800	264
801-900	255
901-1000	226
>1000	1,119

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2018 Customer Counts by Usage

Residential Load Control Service - 8 Hour Switch

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	2
101-200	5
201-300	4
301-400	1
401-500	-
501-600	1
601-700	-
701-800	1
801-900	1
901-1000	-
>1000	-

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2018 Customer Counts by Usage

Residential Load Control Service - 8 Hour No Switch

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	37
101-200	31
201-300	17
301-400	14
401-500	5
501-600	1
601-700	1
701-800	3
801-900	1
901-1000	1
>1000	8

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2018 Customer Counts by Usage

Residential Load Control Service - 10/11 Hour Switch

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	1
101-200	1
201-300	2
301-400	1
401-500	-
501-600	-
601-700	-
701-800	-
801-900	-
901-1000	-

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2018 Customer Counts by Usage

Residential Load Control Service - 10/11 Hour No Switch

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	19
101-200	29
201-300	35
301-400	9
401-500	2
501-600	4
701-800	1
>1000	3

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2018 Customer Counts by Usage

General Service - 1 Phase

AVERAGE 2018 DEMAND (KW)	AVERAGE 2018 USAGE (KWH)	CUSTOMERS
<=3	375	35,001
<=3	<=1000	11,603
<=3	>1000	5444
4-6	<=750	197
4-6	751-1500	631
4-6	>1500	1,893
7-12	<=1500	182
7-12	<=1500	1,620
13-30	<=6000	196
13-30	>6000	451
31-40	<=10000	6
31-40	>10000	34
>40	<=10000	2
>40	>10000	36

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2018 Customer Counts by Usage

General Service 3 Phase

AVERAGE 2018 DEMAND (KW)	AVERAGE 2018 USAGE (KWH)	CUSTOMERS
<=3	<=375	2,922
<=3	376-1000	3,137
<=3	> 1000	3,368
4-6	>=750	103
4-6	751-1500	407
4-6	>1501	2,156
7-12	<=1500	137
7-12	>1500	2,802
13-30	<=6000	788
13-30	>6000	2,518
31-40	<=10000	114
31-40	>10000	649
>40	<=10000	71
>40	>10000	1,081

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2018 Customer Counts by Usage

General Service - Uncontrolled Water Heating

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	687
101-200	211
201-300	108
301-400	93
401-500	44
501-600	35
601-700	26
>700	95

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2018 Customer Counts by Usage

General Service Load Control Service - Radio Controlled

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	4
101-200	7
201-300	6
301-400	4
401-500	6
501-600	13
601-700	6
701-800	16
801-900	19
901-1000	15
>1000	96

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2018 Customer Counts by Usage

General Service Load Control Service - 8 Hour Switch

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	2
101-200	5
201-300	4
301-400	1
401-500	-
501-600	1
601-700	-
701-800	1
801-900	1
901-1000	-
>1000	

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2018 Customer Counts by Usage

General Service Load Control Service - 8 Hour No Switch

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	3
101-200	1
201-300	-
301-400	-
401-500	-
501-600	-
601-700	-
701-800	-
801-900	-
901-1000	-
>1000	2

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2018 Customer Counts by Usage

General Service Load Control Service - 10/11 Hour No Switch

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	-
101-200	-
201-300	-
301-400	-
401-500	-
501-600	-
601-700	-
701-800	-
801-900	-
901-1000	-
>1000	2

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2018 Customer Counts by Usage

General Service - Optional Time of Day

AVERAGE 2018 DEMAND (KW)	AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=12	<=1500	10
<=12	3001-4500	
12-30	<=1500	4
12-30	1500-3000	-
12-30	3001-4500	-
12-30	4501-7500	-
31-50	<=1500	1
31-50	3001-4500	-
31-50	7501-9000	-
51-75	<=1500	-
51-75	1500-3000	-
51-75	4501-7500	-
>75	4501-7500	-

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2018 Customer Counts by Usage

General Service - Optional Time of Day

AVERAGE 2018 DEMAND (KW)	AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=12	<=1500	6
<=12	3001-4500	1
12-30	<=1500	1
12-30	1500-3000	4
12-30	3001-4500	2
12-30	4501-7500	1
31-50	<=1500	1
31-50	3001-4500	1
31-50	7501-9000	1
51-75	<=1500	1
51-75	1500-3000	1
51-75	4501-7500	1
>75	4501-7500	2

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2018 Customer Counts by Usage

General Service - Space Heating

AVERAGE 2018 USAGE (kWh)	CUSTOMERS
<=100	56
101-200	39
201-300	36
301-400	29
401-500	24
501-600	29
601-700	31
>700	181

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2018 Customer Counts by Usage

Rate GV

AVERAGE 2018 DEMAND (KW)	AVERAGE 2018 USAGE (KWH)	CUSTOMERS
<=75	<=15,000	57
	15,001-30,000	34
	31,001-60,000	5
76-150	<=15,000	12
	15,001-30,000	89
	31,001-60,000	315
	60,001-120,000	47
151-300	<=15,000	10
	15,001-30,000	19
	31,001-60,000	121
	60,001-120,000	283
	120,001-200,000	58
301-500	15,001-30,000	2
	31,001-60,000	7
	60,001-120,000	52
	120,001-200,000	108
	200,001-400,000	70
501-1000	<=15,000	1
	60,001-120,000	6
	120,001-200,000	20
	200,001-400,000	89
	>400,000	18
>1000	200,001-400,000	3
	>400,000	6

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2018 Customer Counts by Usage

Rate LG

AVERAGE 2018 DEMAND (KVA)	AVERAGE 2018 USAGE (KWH)	CUSTOMERS
<=3000	<=300,000	17
	300,001-600,000	30
	600,001-900,000	26
	900,001-1,200,000	11
	1,200,001-1,500,00	9
	1,500,001-1,800,00	1
>3000	300,001-600,000	1
	1,500,001-1,800,00	6
	1,800,001-2,100,00	3
	>2,100,000	7

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Typical Bills by Rate Schedule

Residential Service - Rate R

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 30.84	$ 33.34	$ 2.50	8.11%
200	48.99	52.79	3.80	7.76%
250	58.06	62.51	4.45	7.66%
300	67.14	72.24	5.10	7.60%
400	85.29	91.69	6.40	7.50%
500	103.44	111.14	7.70	7.44%
600	121.58	130.58	9.00	7.40%
700	139.73	150.03	10.30	7.37%
750	148.81	159.76	10.95	7.36%
1,000	194.18	208.38	14.20	7.31%
1,500	284.93	305.63	20.70	7.27%
2,000	375.67	402.87	27.20	7.24%
2,500	466.42	500.12	33.70	7.23%
3,000	557.16	597.36	40.20	7.22%
5,000	920.14	986.34	66.20	7.19%
7,500	1373.87	1472.57	98.70	7.18%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 12.69	$ 13.89	$ 1.20
Distribution Charge per kWh	0.04141	0.05441	0.01300
Transmission Charge per kWh	0.02039	0.02039	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.01398	0.01398	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Residential Service - Uncontrolled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.05	$ 21.31	$ 1.27	6.31%
200	35.62	37.73	2.11	5.92%
300	51.20	54.16	2.96	5.77%
400	66.78	70.58	3.80	5.69%
500	82.36	87.00	4.65	5.64%
600	97.93	103.42	5.49	5.61%
700	113.51	119.84	6.34	5.58%
800	129.09	136.27	7.18	5.56%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 4.47	$ 4.89	$ 0.42
Distribution Charge per kWh	0.02030	0.02875	0.00845
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.01398	0.01398	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Residential Service - Controlled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
AVERAGE 2018 USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.98	$ 19.36	$ (1.61)	-7.68%
200	34.07	33.84	(0.23)	-0.69%
300	47.17	48.31	1.14	2.43%
400	60.26	62.79	2.52	4.18%
500	73.36	77.26	3.90	5.32%
600	86.46	91.73	5.28	6.10%
700	99.55	106.21	6.66	6.69%
800	112.65	120.68	8.03	7.13%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 7.88	$ 4.89	$ (2.99)
Distribution Charge per kWh	0.00120	0.01498	0.01378
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00827	0.00827	-
System Benefits Charge	0.00586	0.00586	-

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Typical Bills by Rate Schedule

Residential Service - Optional Time of Day

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 47.78	$ 51.94	$ 4.16	8.70%
200	66.09	71.62	5.53	8.37%
250	75.25	81.46	6.22	8.27%
300	84.40	91.31	6.91	8.18%
400	102.71	110.99	8.28	8.06%
500	121.02	130.68	9.66	7.98%
750	166.80	179.89	13.10	7.85%
1,000	212.57	229.11	16.54	7.78%
1,500	304.12	327.54	23.41	7.70%
2,000	395.68	425.97	30.29	7.66%
2,500	487.23	524.40	37.17	7.63%
3,000	578.78	622.83	44.05	7.61%
5,000	944.98	1,016.55	71.56	7.57%
7,500	1,402.74	1,508.69	105.95	7.55%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 29.47	$ 32.25	$ 2.78
Energy Charge On Peak kWh			
Distribution	$ 0.13235	$ 0.15394	$ 0.02159
Transmission	0.02039	0.02039	-
Stranded Cost Recovery Charge	0.01208	0.01208	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total per On Peak kWh	0.27053	0.29212	0.02159
Energy Charge Off Peak kWh			
Distribution	$ 0.00193	$ 0.01120	$ 0.00927
Transmission	0.01331	0.01331	-
Stranded Cost Recovery Charge	0.01208	0.01208	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total per Off Peak kWh	0.13303	0.14230	0.00927
% Sales On Peak	36%	36%	
% Sales Off Peak	64%	64%	

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Residential Load Control Service - Radio Controlled

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 22.21	$ 24.43	$ 2.22	9.99%
200	35.30	37.55	2.25	6.37%
300	48.40	50.68	2.28	4.70%
400	61.49	63.80	2.31	3.75%
500	74.59	76.93	2.34	3.13%
600	87.69	90.05	2.36	2.70%
700	100.78	103.18	2.39	2.37%
800	113.88	116.30	2.42	2.13%
900	126.97	129.43	2.45	1.93%
1,000	140.07	142.55	2.48	1.77%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 9.11	$ 11.30	$ 2.19
Distribution Charge per kWh	0.00120	0.00149	0.00029
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00827	0.00827	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Residential Load Control Service - 8 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 22.21	$ 19.36	$ (2.84)	-12.80%
200	35.30	33.84	(1.46)	-4.15%
300	48.40	48.31	(0.09)	-0.18%
400	61.49	62.79	1.29	2.10%
500	74.59	77.26	2.67	3.58%
600	87.69	91.73	4.05	4.62%
700	100.78	106.21	5.43	5.38%
800	113.88	120.68	6.80	5.97%
900	126.97	135.16	8.18	6.44%
1,000	140.07	149.63	9.56	6.83%
1,200	166.26	178.58	12.32	7.41%
1,500	205.55	222.00	16.45	8.00%
1,800	244.84	265.42	20.58	8.41%
2,000	271.03	294.37	23.34	8.61%
2,500	336.51	366.74	30.23	8.98%
3,000	401.99	439.11	37.12	9.23%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 9.11	$ 4.89	$ (4.22)
Distribution Charge per kWh	0.00120	0.01498	0.01378
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00827	0.00827	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Residential Load Control Service - 8 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.98	$ 19.36	$ (1.61)	-7.68%
200	34.07	33.84	(0.23)	-0.69%
300	47.17	48.31	1.14	2.43%
400	60.26	62.79	2.52	4.18%
500	73.36	77.26	3.90	5.32%
600	86.46	91.73	5.28	6.10%
700	99.55	106.21	6.66	6.69%
800	112.65	120.68	8.03	7.13%
900	125.74	135.16	9.41	7.49%
1,000	138.84	149.63	10.79	7.77%
1,200	165.03	178.58	13.55	8.21%
1,500	204.32	222.00	17.68	8.65%
1,800	243.61	265.42	21.81	8.95%
2,000	269.80	294.37	24.57	9.11%
2,500	335.28	366.74	31.46	9.38%
3,000	400.76	439.11	38.35	9.57%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$7.88	$4.89	(2.99)
Distribution Charge per kWh	$0.00120	$0.01498	0.01378
Transmission Charge per kWh	$0.01578	$0.01578	-
Energy Service Charge	$0.09985	$0.09985	-
Stranded Cost Recovery Charge	$0.00827	$0.00827	-
System Benefits Charge	$0.00586	$0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Residential Load Control Service - 10/11 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 24.53	$ 20.74	$ (3.79)	-15.46%
200	39.96	36.59	(3.37)	-8.42%
300	55.38	52.44	(2.94)	-5.31%
400	70.81	68.29	(2.51)	-3.55%
500	86.23	84.15	(2.08)	-2.42%
600	101.65	100.00	(1.66)	-1.63%
700	117.08	115.85	(1.23)	-1.05%
800	132.50	131.70	(0.80)	-0.61%
900	147.93	147.55	(0.38)	-0.25%
1,000	163.35	163.40	0.05	0.03%
1,200	194.20	195.10	0.90	0.47%
1,500	240.47	242.66	2.19	0.91%
1,800	286.74	290.21	3.47	1.21%
2,000	317.59	321.91	4.32	1.36%
2,500	394.71	401.17	6.46	1.64%
3,000	471.83	480.42	8.59	1.82%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$9.11	$4.89	(4.22)
Distribution Charge per kWh	$0.02448	$0.02875	0.00427
Transmission Charge per kWh	$0.01578	$0.01578	-
Energy Service Charge	$0.09985	$0.09985	-
Stranded Cost Recovery Charge	$0.00827	$0.00827	-
System Benefits Charge	$0.00586	$0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Residential Load Control Service - 10/11 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 23.30	$ 20.74	$ (2.56)	-11.00%
200	38.73	36.59	(2.14)	-5.52%
300	54.15	52.44	(1.71)	-3.16%
400	69.58	68.29	(1.28)	-1.84%
500	85.00	84.15	(0.85)	-1.01%
600	100.42	100.00	(0.43)	-0.43%
700	115.85	115.85	(0.00)	0.00%
800	131.27	131.70	0.43	0.32%
900	146.70	147.55	0.85	0.58%
1,000	162.12	163.40	1.28	0.79%
1,200	192.97	195.10	2.13	1.11%
1,500	239.24	242.66	3.42	1.43%
1,800	285.51	290.21	4.70	1.64%
2,000	316.36	321.91	5.55	1.75%
2,500	393.48	401.17	7.69	1.95%
3,000	470.60	480.42	9.82	2.09%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$7.88	$4.89	(2.99)
Distribution Charge per kWh	$0.02448	$0.02875	0.00427
Transmission Charge per kWh	$0.01578	$0.01578	-
Energy Service Charge	$0.09985	$0.09985	-
Stranded Cost Recovery Charge	$0.00827	$0.00827	-
System Benefits Charge	$0.00586	$0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

General Service 1 Phase

(A)	(B)	(C)	(D)	(E) = (D) - (C)	(F) = (E) / (C)
USAGE		TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
3	375	$ 91.86	$ 97.45	$ 5.58	6.08%
3	1,000	187.95	195.18	7.23	3.84%
6	750	167.68	176.27	8.60	5.13%
6	1,500	273.32	283.14	9.82	3.59%
12	1,500	362.96	383.46	20.50	5.65%
30	6,000	1,200.46	1,255.61	55.15	4.59%
40	10,000	1,855.26	1,930.53	75.27	4.06%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 14.89	$ 18.00	$ 3.11
Demand Charge >5kWh			
Distribution	$ 8.72	$ 10.50	$ 1.78
Transmission	5.26	5.26	-
Stranded Cost Recovery Charge	0.96	0.96	-
Total	$ 14.94	$ 16.72	$ 1.78
Energy Charge < 500kWh			
Distribution	$ 0.06986	$ 0.07646	$ 0.00660
Transmission	0.01900	0.01900	-
Stranded Cost Recovery Charge	0.01069	0.01069	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total	$ 0.20526	$ 0.21186	$ 0.00660
Energy Charge 501 - 1500 kWh			
Distribution	$ 0.01731	$ 0.01894	$ 0.00163
Transmission	0.00715	0.00715	-
Stranded Cost Recovery Charge	0.01069	0.01069	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total	$ 0.14086	$ 0.14249	$ 0.00163
Energy Charge >1500 kWh			
Distribution	$ 0.00612	$ 0.00670	$ 0.00058
Transmission	0.00383	0.00383	-
Stranded Cost Recovery Charge	0.01069	0.01069	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total	$ 0.12635	$ 0.12693	$ 0.00058

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service 3 Phase

(A)	(B)	(C)	(D)	(E) = (D) - (C)	(F) = (E) / (C)
USAGE		TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
3	375	$ 106.73	$ 115.45	$ 8.71	8.17%
3	1,000	202.82	213.18	10.36	5.11%
6	750	182.55	194.27	11.73	6.42%
6	1,500	288.19	301.14	12.95	4.49%
12	1,500	377.83	401.46	23.63	6.25%
30	6,000	1,215.33	1,273.61	58.28	4.80%
40	10,000	1,870.13	1,948.53	78.40	4.19%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 29.76	$ 36.00	$ 6.24
Demand Charge >5kWh			
Distribution	$ 8.72	$ 10.50	1.78
Transmission	5.26	5.26	-
Stranded Cost Recovery Charge	0.96	0.96	-
Total	$ 14.94	$ 16.72	$ 1.78
Energy Charge < 500kWh			
Distribution	$ 0.06986	$ 0.07646	$ 0.00660
Transmission	0.01900	0.01900	-
Stranded Cost Recovery Charge	0.01069	0.01069	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total	$ 0.20526	$ 0.21186	$ 0.00660
Energy Charge 501 - 1500 kWh			
Distribution	$ 0.01731	$ 0.01894	$ 0.00163
Transmission	0.00715	0.00715	-
Stranded Cost Recovery Charge	0.01069	0.01069	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total	$ 0.14086	$ 0.14249	$ 0.00163
Energy Charge >1500 kWh			
Distribution	$ 0.00612	$ 0.00670	$ 0.00058
Transmission	0.00383	0.00383	-
Stranded Cost Recovery Charge	0.01069	0.01069	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total	$ 0.12635	$ 0.12693	$ 0.00058

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service - Uncontrolled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 19.99	$ 21.25	$ 1.27	6.33%
200	35.50	37.61	2.11	5.94%
300	51.02	53.98	2.96	5.79%
400	66.54	70.34	3.80	5.71%
500	82.06	86.70	4.65	5.66%
600	97.57	103.06	5.49	5.63%
700	113.09	119.42	6.34	5.60%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 4.47	$ 4.89	$ 0.42
Distribution Charge per kWh	0.02030	0.02875	0.00845
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.01338	0.01338	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

General Service - Controlled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.94	$ 19.33	$ (1.61)	-7.70%
200	34.00	33.76	(0.23)	-0.69%
300	47.06	48.20	1.14	2.43%
400	60.12	62.64	2.52	4.20%
500	73.18	77.08	3.90	5.33%
600	86.23	91.51	5.28	6.12%
700	99.29	105.95	6.66	6.70%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 7.88	$ 4.89	$ (2.99)
Distribution Charge per kWh	0.00120	0.01498	0.01378
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

General Service Load Control Service - Radio Controlled

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 22.17	$ 24.39	$ 2.22	10.01%
200	35.23	37.48	2.25	6.38%
300	48.29	50.56	2.28	4.72%
400	61.35	63.65	2.31	3.76%
500	74.41	76.74	2.34	3.14%
600	87.46	89.83	2.36	2.70%
700	100.52	102.92	2.39	2.38%
800	113.58	116.00	2.42	2.13%
900	126.64	129.09	2.45	1.94%
1,000	139.70	142.18	2.48	1.78%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 9.11	$ 11.30	$ 2.19
Distribution Charge per kWh	0.00120	0.00149	0.00029
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service Load Control Service - 8 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 22.17	$ 19.33	$ (2.84)	-12.82%
200	35.23	33.76	(1.46)	-4.16%
300	48.29	48.20	(0.09)	-0.18%
400	61.35	62.64	1.29	2.11%
500	74.41	77.08	2.67	3.59%
600	87.46	91.51	4.05	4.63%
700	100.52	105.95	5.43	5.40%
800	113.58	120.39	6.80	5.99%
900	126.64	134.82	8.18	6.46%
1,000	139.70	149.26	9.56	6.84%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 9.11	$ 4.89	$ (4.22)
Distribution Charge per kWh	0.00120	0.01498	0.01378
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

General Service Load Control Service - 8 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.94	$ 19.33	$ (1.61)	-7.70%
200	34.00	33.76	(0.23)	-0.69%
300	47.06	48.20	1.14	2.43%
400	60.12	62.64	2.52	4.20%
500	73.18	77.08	3.90	5.33%
600	86.23	91.51	5.28	6.12%
700	99.29	105.95	6.66	6.70%
800	112.35	120.39	8.03	7.15%
900	125.41	134.82	9.41	7.50%
1,000	138.47	149.26	10.79	7.79%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 7.88	$ 4.89	$ (2.99)
Distribution Charge per kWh	0.00120	0.01498	0.01378
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

General Service Load Control Service - 10/11 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY	CURRENT	PROPOSED	AMOUNT	PERCENT
(kWh)				
100	$ 24.50	$ 20.70	$ (3.79)	-15.48%
200	39.88	36.52	(3.37)	-8.44%
300	55.27	52.33	(2.94)	-5.32%
400	70.66	68.15	(2.51)	-3.56%
500	86.05	83.96	(2.08)	-2.42%
600	101.43	99.77	(1.66)	-1.63%
700	116.82	115.59	(1.23)	-1.05%
800	132.21	131.40	(0.80)	-0.61%
900	147.59	147.22	(0.38)	-0.26%
1,000	162.98	163.03	0.05	0.03%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 9.11	$ 4.89	$ (4.22)
Distribution Charge per kWh	0.02448	0.02875	0.00427
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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General Service Load Control Service - 10/11 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 23.27	$ 20.70	$ (2.56)	-11.02%
200	38.65	36.52	(2.14)	-5.53%
300	54.04	52.33	(1.71)	-3.16%
400	69.43	68.15	(1.28)	-1.85%
500	84.82	83.96	(0.85)	-1.01%
600	100.20	99.77	(0.43)	-0.43%
700	115.59	115.59	(0.00)	0.00%
800	130.98	131.40	0.43	0.33%
900	146.36	147.22	0.85	0.58%
1,000	161.75	163.03	1.28	0.79%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 7.88	$ 4.89	$ (2.99)
Distribution Charge per kWh	0.02448	0.02875	0.00427
Transmission Charge per kWh	0.01578	0.01578	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service - Optional Time of Day
Single Phase

(A)	(B)	(C)	(D)	(E)	(F)	(G) = (F) - (E)	(H) = (G) / (E)
				TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (kWh)	ON-PEAK USE (kWh)	OFF-PEAK USE (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
12	1,500	600	900	$ 438.50	$ 470.90	$ 32.40	7.39%
12	1,500	900	600	450.90	484.47	33.57	7.44%
12	3,000	1,200	1,800	645.24	681.07	35.83	5.55%
12	3,000	1,800	1,200	670.03	708.20	38.17	5.70%
30	4,500	1,800	2,700	1,141.77	1,219.01	77.25	6.77%
30	4,500	2,700	1,800	1,178.97	1,259.72	80.76	6.85%
30	9,000	3,600	5,400	1,761.97	1,849.52	87.55	4.97%
30	9,000	5,400	3,600	1,836.36	1,930.93	94.57	5.15%
50	7,500	3,000	4,500	1,877.24	2,003.55	126.32	6.73%
50	7,500	4,500	3,000	1,939.23	2,071.40	132.17	6.82%
50	15,000	6,000	9,000	2,910.90	3,054.39	143.49	4.93%
50	15,000	9,000	6,000	3,034.89	3,190.08	155.19	5.11%
75	11,250	4,500	6,750	2,796.57	2,984.22	187.65	6.71%
75	11,250	6,750	4,500	2,889.56	3,085.99	196.43	6.80%
75	22,500	9,000	13,500	4,347.07	4,560.48	213.42	4.91%
75	22,500	13,500	9,000	4,533.05	4,764.02	230.97	5.10%

	Current Rate	Proposed Rate	Difference
Customer Charge - Single Phase	$ 38.57	$ 42.21	$ 3.64
Demand Charges			
Distribution	$ 12.15	$ 14.26	$ 2.11
Transmission	3.47	3.47	-
Stranded Cost Recovery	0.48	0.48	-
Total Demand Charge	16.10	18.21	2.11
Energy Charge On Peak kWh			
Distribution	$ 0.04901	$ 0.05364	$ 0.00463
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total per On Peak kWh	0.16262	0.16725	0.00463
Energy Charge Off Peak kWh			
Distribution	$ 0.00768	$ 0.00841	$ 0.00073
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00790	0.00790	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.09985	0.09985	-
Total per Off Peak kWh	0.12129	0.12202	0.00073

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

General Service - Optional Time of Day
Three Phase

(A)	(B)	(C)	(D)	(E)	(F)	(G) = (F) - (E)	(H) = (G) / (E)
				TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND	MONTHLY USE	ON-PEAK USE	OFF-PEAK USE	CURRENT	PROPOSED	AMOUNT	PERCENT
(KW)	(kWh)	(kWh)	(kWh)				
12	1,500	600	900	$ 455.05	$ 489.01	$ 33.96	7.46%
12	1,500	900	600	467.45	502.58	35.13	7.51%
12	3,000	1,200	1,800	661.79	699.18	37.39	5.65%
12	3,000	1,800	1,200	686.58	726.31	39.73	5.79%
30	4,500	1,800	2,700	1,158.32	1,237.12	78.81	6.80%
30	4,500	2,700	1,800	1,195.52	1,277.83	82.32	6.89%
30	9,000	3,600	5,400	1,778.52	1,867.63	89.11	5.01%
30	9,000	5,400	3,600	1,852.91	1,949.04	96.13	5.19%
50	7,500	3,000	4,500	1,893.79	2,021.66	127.88	6.75%
50	7,500	4,500	3,000	1,955.78	2,089.51	133.73	6.84%
50	15,000	6,000	9,000	2,927.45	3,072.50	145.05	4.95%
50	15,000	9,000	6,000	3,051.44	3,208.19	156.75	5.14%
75	11,250	4,500	6,750	2,813.12	3,002.33	189.21	6.73%
75	11,250	6,750	4,500	2,906.11	3,104.10	197.99	6.81%
75	22,500	9,000	13,500	4,363.62	4,578.59	214.97	4.93%
75	22,500	13,500	9,000	4,549.60	4,782.13	232.53	5.11%

		Current Rate	Proposed Rate	Difference
Customer Charge - Three Phase		$ 55.12	$ 60.32	$ 5.20
Demand Charges				
Distribution		$ 12.15	$ 14.26	$ 2.11
Transmission		3.47	3.47	-
Stranded Cost Recovery		0.48	0.48	-
Total Demand Charge		16.10	18.21	2.11
Energy Charge On Peak kWh				
Distribution		$ 0.04901	$ 0.05364	$ 0.00463
Transmission		-	-	-
Stranded Cost Recovery Charge		0.00790	0.00790	-
System Benefits Charge		0.00586	0.00586	-
Energy Service Charge		0.09985	0.09985	-
Total per On Peak kWh		0.16262	0.16725	0.00463
	36.42%			
Energy Charge Off Peak kWh				
Distribution		$ 0.00768	$ 0.00841	$ 0.00073
Transmission		-	-	-
Stranded Cost Recovery Charge		0.00790	0.00790	-
System Benefits Charge		0.00586	0.00586	-
Energy Service Charge		0.09985	0.09985	-
Total per Off Peak kWh		0.12129	0.12202	0.00073

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

General Service - Space Heating

	(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
	USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
#REF!	ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
56	100	$ 20.54	$ 21.44	$ 0.90	4.37%
39	200	38.11	39.62	1.51	3.97%
36	300	55.67	57.80	2.13	3.83%
29	400	73.23	75.98	2.75	3.75%
24	500	90.80	94.16	3.36	3.71%
29	600	108.36	112.34	3.98	3.67%
31	700	125.92	130.52	4.60	3.65%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 2.98	$ 3.26	$ 0.28
Distribution Charge per kWh	0.03426	0.04043	0.00617
Transmission Charge per kWh	0.01900	0.01900	-
Energy Service Charge	0.09985	0.09985	-
Stranded Cost Recovery Charge	0.01666	0.01666	-
System Benefits Charge	0.00586	0.00586	-

Note: Immaterial differences due to rounding.

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Typical Bills by Rate Schedule

Rate GV

(A)	(B)	(C)	(D)	(E) = (D) - (C)	(F) = (E) / (C)
USAGE		TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
75	15,000	$ 3,342.38	$ 3,466.05	$ 123.67	3.70%
75	30,000	5,481.98	5,614.20	132.22	2.41%
150	30,000	6,478.73	6,691.95	213.22	3.29%
150	60,000	10,757.93	10,988.25	230.32	2.14%
300	60,000	12,739.43	13,130.25	390.82	3.07%
300	120,000	21,297.83	21,722.85	425.02	2.00%
500	100,000	21,087.03	21,714.65	627.62	2.98%
500	200,000	35,351.03	36,035.65	684.62	1.94%
1,000	200,000	41,956.03	43,175.65	1,219.62	2.91%
1,000	400,000	70,290.03	71,605.65	1,315.62	1.87%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 194.03	$ 226.65	$ 32.62
Demand 1-100 kW			
Distribution	$ 5.58	$ 6.68	$ 1.10
Transmission	7.04	7.04	-
Stranded Cost Recovery Charge	0.83	0.83	-
Total	$ 13.45	$ 14.55	$ 1.10
Demand > 100 kW			
Distribution	$ 5.34	$ 6.41	$ 1.07
Transmission	7.04	7.04	-
Stranded Cost Recovery Charge	0.83	0.83	-
Total	$ 13.21	$ 14.28	$ 1.07
Energy Charge 1 - 200,000 kWh			
Distribution	$ 0.00606	$ 0.00663	$ 0.00057
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00850	0.00850	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.12222	0.12222	-
Total	$ 0.14264	$ 0.14321	$ 0.00057
Energy Charge >200,000 kWh			
Distribution	$ 0.00509	$ 0.00557	$ 0.00048
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00850	0.00850	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.12222	0.12222	-
Total	$ 0.14167	$ 0.14215	$ 0.00048

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

Rate LG

(A)	(B)	(C)	(D)	(E)	(F)	(G) = (F) - (E)	(H) = (G) / (E)
				TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KVA)	MONTHLY USE (KWH)	ON-PEAK USE (KWH)	OFF-PEAK USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
3,000	300,000	120,000	180,000	$ 76,967.27	$ 80,452.08	$ 3,484.81	4.53%
3,000	600,000	240,000	360,000	117,388.07	121,004.28	3,616.21	3.08%
3,000	900,000	360,000	540,000	157,808.87	161,556.48	3,747.61	2.37%
3,000	1,200,000	480,000	720,000	198,229.67	202,108.68	3,879.01	1.96%
3,000	1,500,000	600,000	900,000	238,650.47	242,660.88	4,010.41	1.68%
3,000	1,800,000	720,000	1,080,000	279,071.27	283,213.08	4,141.81	1.48%
3,000	2,100,000	840,000	1,260,000	319,492.07	323,765.28	4,273.21	1.34%

	Current Rate Rate	Proposed Rate	Difference
Customer Charge	$ 606.47	$ 719.88	$ 113.41
Demand			
Distribution	$ 4.75	$ 5.83	$ 1.08
Transmission	6.93	6.93	-
Stranded Cost Recovery Charge	0.30	0.30	-
Total	$ 11.98	$ 13.06	$ 1.08
Energy Charge - On-Peak			
Distribution	$ 0.00508	$ 0.00556	$ 0.00048
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00256	0.00256	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.12222	0.12222	-
Total	$ 0.13572	$ 0.13620	$ 0.00048
Energy Charge - Off-Peak			
Distribution	$ 0.00429	$ 0.00470	$ 0.00041
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00171	0.00171	-
System Benefits Charge	0.00586	0.00586	-
Energy Service Charge	0.12222	0.12222	-
Total	$ 0.13408	$ 0.13449	$ 0.00041

Note: Immaterial differences due to rou 36.42%

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. OCA 6-108 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Edward A. Davis

Request:
Reference Davis Testimony, Bates 1805, Lines 3-5, stating "The Company has applied differing degrees of gradualism with respect to the target level of revenue requirement by class and resulting overall impact on customer bills. Please explain the differing degrees of gradualism the Company applied by class, identifying any caps the Company utilized.

Response:
The Company relied on results of its cost of service studies at a class level to inform the degree of gradualism applied in developing proposed class revenue requirements, from which proposed rates were designed. As discussed in Mr. Davis' Testimony (Bates page 1804), one aspect of gradualism applied in the Company's proposal is to allocate revenue requirements to each class in a manner that moves the rate of return ("ROR") for each class closer to the required return, as informed by the allocated cost of service study ("ACOSS"). The difference between the earned ROR and required ROR varied by class. In deciding the extent of change to propose for each class, the Company considered the overall average Company-level increase requested along with the relative ROR of each class (i.e., earned vs proposed as informed by the ACOSS), along with ultimate customer bill impacts to determine the degree of change to each rate class.

As a guide in performing the initial allocation of revenue requirements to each class, the Company limited the overall distribution revenue requirement increase of any class to 20% above the overall Company average increase. Accordingly, given the proposed, overall Company average rate change of 19.9 % (see Attachment EAD-5, Bates page 2047), individual class increases were limited to approximately 24% (19.9% x 120%). Because the class RORs for Rate R, R-TOD, Water Heating and LCS are significantly less than average (see Attachment EAD-5, Bates page 2049), increases to their respective revenue requirements would need to be significantly higher than average in order to achieve the full target ROR.

Limiting the revenue requirement increase in each class to no more than 24% provides a degree of gradualism for each class, while resulting in different impacts for each class, depending on their relative ROR and amount of revenue deficiency, compared with the target ROR. The current RORs for Rates G, GV, LG and B are greater than the average target ROR. However, the 24 percent constraint in rate increases of other classes meant that allocations to these rates needed to be adjusted to achieve the overall revenue requirement increase. Accordingly, revenue requirement allocations to these classes were less than average and were applied in a manner that moved the RORs closer to the average. Given the restructuring and proposed design of rates for outdoor lighting, revenue requirements for

Rates OL and EOL were set at the level of the ACOSS, which results in a rate decrease for these classes (See Attachment EAD-5 at Bates page 2049).

To summarize, the revenue requirement allocations by class reflect the degree of gradualism applied in proposing changes to each class' ROR relative to their respective, current levels, so that each class moves closer to the required return but subject to the above described limits in overall class bill impact. This exercise required reaching a balance between the degree of changes collectively made among rate classes to achieve the overall system revenue requirement increase. Another aspect of gradualism was to review whether the proposed bill change in absolute dollars for the average customer in the residential or other classes would represent a rate shock, even if within the constraints applied. The Company did not find this to be the case, and expects that the average residential customer would will see a change of no greater than 4.4% relative to temporary rate levels. This was considered a reasonable impact consistent with maintaining a gradual approach to the required rate changes.

Finally, the Company relied on the ACOSS to inform these allocations, but also reviewed the potential for utilizing targets based on the results of the marginal cost study, which were found to support the direction of the allocations ultimately applied in the Company's filed proposal.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/11/2019 **Date of Response: 10/25/2019**
Request No. STAFF 14-011 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Edward A. Davis

Request:
Reference Edward A. Davis testimony, Bates 01811 lines 12-14 "Application of the bounds in setting residential, water heating [sic], and LCS rates resulted in "residual" revenue requirements, which were allocated to Rates G, GV, LG, and B.

a. Please describe the bounds used for each rate class.
b. Please provide the rationale for the bounds used.
c. Please compare these bounds to those used in prior rate cases.
d. Provide live workbooks with all formulas intact that include the bounds used for the rate classes, the calculation of the residual revenue requirement, and the allocation of those residual revenue requirement.

Response:

a) When establishing its allocations of revenue requirements to each class, the Company limited the overall distribution revenue requirement increase of any class to 20% above the overall average rate increase. Rates R, R-OTOD, LCS, and Water Heating were set at the limit of 20% above the overall average increase. The Controlled Water Heating class is being phased in over two (2) years at the Uncontrolled Water Heating levels, see Bates 1809 and 1810. The Non-Radio Controlled LCS is being phased in over two (2) years at the Uncontrolled Water Heating levels, see Bates 1811.
b) The Company relied on experience and judgement, and general proportions of revenue requirements among classes, in developing revenue allocations in other jurisdictions to determine that the 20% above average increase was reasonable for rate classes with significantly lower Rate of Return's ("ROR") than the Company average.
c) In Docket DE 09-035, Mr. Hall's testimony indicated that the Company was not attempting to reallocate revenues between rate classes. Rather, the Company was proposing the same percentage increase among all rate classes. The current rate case is the first in many years to develop alternate allocations and design rates for each class.
d) Please see response to OCA 1-001, Attachment EAD-4 to EAD-9, and Davis Testimony at Bates 2048 for the calculation of the residual revenue requirements and residual revenue allocations.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/11/2019 **Date of Response: 10/25/2019**
Request No. STAFF 14-019 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Edward A. Davis

Request:
Reference Edward A. Davis testimony, Bates 001809, lines 1-3: "To maintain consistency with current rates, the Company kept the current price differential between on-peak and off-peak rates and maintained the current TOD period in taking the incremental change from temporary to permanent rates". Please explain why maintaining consistency has been selected as the guiding principle in the design of the TOD rates, instead of reevaluating the peak and offpeak prices, as well as peak and offpeak periods and potentially improving efficiency of the price signals.

Response:
The guiding principles employed in designing the proposed rates include rate continuity, gradualism, cost-based revenue requirement class allocation and efficiency. The Company has evaluated potential changes to TOD rates where applicable across all rate classes, and intends to continue to move toward more marginal cost based structures and efficient rates in future rates cases. As discussed in response to Staff 14-016, MCOS-based results have informed aspects of the ACOS study and allocated revenue targets are directionally consistent for the most part. In rate design the Company has sought to strike a balance among various rate design objectives. Guidance from the MCOSS is to change both price differential and peak period duration, potentially extending that further to seasonally differentiated rates. We have taken steps to achieve more efficient rates by moving customer charges closer to those indicated by the MCOS, thus providing greater alignment of marginal demand-related cost recovery with volumetric or demand related charges. We have considered additional changes in TOD rates to achieve more efficient pricing in the longer term but not in this rate case due to keeping in mind all aspects of rate design which include consistency and continuity. In a number of responses (e.g., Staff 14-008 and OCA 6-108) the Company has discussed the challenges to implement changes and implement new TOD structures across numerous rate classes and to other components of service (e.g., transmission). Rate continuity will continue to be an important principle, and was an important consideration in maintaining the current peak to off peak price differential in the Company's proposal in this case, as we look to make structural changes going forward.