Docket No. DE 19-064
Exhibit 26

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 19-064

IN THE MATTER OF: **Liberty Utilities (Granite State Electric) Corp.**
d/b/a Liberty Utilities

Distribution Service Rate Case
.

DIRECT TESTIMONY

OF

SANEM I. SERGICI

December 06, 2019

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I. STATEMENT OF QUALIFICATIONS

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

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

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. 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 No, I have not.

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 application of the Marginal Cost of Service (MCOS) study to determine class revenue targets and design proposed permanent rates by Witness Heintz for Liberty Utilities (the “Company”).

Q **What are the major findings from your analyses?**

A Major findings of my analyses are as follows:

- Witness Heintz' use of the marginal cost study for determining the class revenue targets is appropriate and consistent with the widely accepted implementation practices in the industry.
- The Company should 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 consider further increasing the customer charges for the residential class, instead of relying on the revenue decoupling for the recovery of the fixed costs.
- The Company should try to minimize unintended intra class subsidies by cost reflective rate design, and analyze the benefits and costs for metering infrastructure that would enable alternative rate designs for residential customers.

Q How is your testimony organized?

A Section III discusses the principles of rate design. Section IV evaluates the Company's use of the MCOS study to determine the class revenue targets 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,

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

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 kWh's in Year 1, and the number of kWh's halves in Year 2, then the effective price per kWh in Year 2 will need to double even though there is no change in the underlying infrastructure cost of the utility, leading to substantial bill fluctuations for some customers.
5. *Customer Satisfaction* – Rates should enhance customer satisfaction. Rates need to be relatively simple so that customers can understand them and respond to the rates 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. USE OF MCOS STUDY TO DETERMINE CLASS REVENUE TARGETS

Q What is the economic rationale for using the results of a marginal cost study to inform rate design?

A Economic theory predicates that pricing goods at the marginal cost maximizes economic efficiency as it mimics the pricing structure and resulting resource allocation of a competitive market.[2] Professor Alfred Kahn introduced marginal cost pricing to the utility regulation in his seminal book, The Economics of Regulation (1970), as a way to bring economic efficiency to regulated utilities.

Q Is it possible to design rates purely based on the marginal costs?

A While it is 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 are almost never equal, and designing the rates based on marginal costs may lead to over or under collection of the revenue requirement.

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 allocation targets in a way to conform to the revenue requirement. This adjustment is called “revenue reconciliation.” There are four widely used revenue reconciliation methods: i) inverse elasticity; ii) lump-sum transfer; iii) differential adjustment of marginal cost components; and iv) equiproportional adjustment. The goal in revenue reconciliation should be to do the least harm to the efficiency of the marginal cost-based rates.

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

Q **Which revenue reconciliation method did Witness Heintz use to adjust for the difference between the Company's proposed revenue requirement and MCOS-based class revenue targets?**

A Witness Heintz used the equiproportional adjustment method which involves increasing or decreasing all rate components for all classes *equally by a factor* sufficient to yield the revenue requirement.[3]

Q **Is equiproportional approach a broadly accepted way to adjust for the difference between proposed revenue requirements and MCOS-based rates?**

A Yes. The goal of a revenue reconciliation mechanism is to ensure the recovery of revenue requirement with a minimum distortion to the marginal cost price signals. At the same time, it is essential to balance inter-class fairness and equity considerations. The equiproportional approach strikes a good balance among these considerations.

Q **Following the equiproportional adjustment to class-based revenue targets, how did Witness Heintz incorporate caps on increases in class-based revenue targets?**

A At a high level, Witness Heintz applied an iterative process whereby 1) a cap is calculated for the total target class-based revenue targets, 2) the revenue shortfall between the total proposed revenue requirement and resulting sum of all class-based revenue targets is determined and 3) the shortfall is allocated to rate classes below the caps according to the class's pro rata share of total revenues at current rates. In more detail, beginning with the MCOS-based revenue targets by class, Witness Heintz:

1. Calculates potential increase in base revenues as the percentage difference between historical and MCOS-based revenue targets by class
2. For any class with a <u>decrease</u> in target revenues (relative to historical), increases the revenue target to be neutral (0% change between proposed and historical)
3. If any class has a target revenue above the cap (120% of the total revenue requirement percentage increase; equivalent to a revenue target increase of 17.15%),[4] reduces that class's target revenue requirement to the cap

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[3] Note that Witness Heintz applied the equiproportional approach for all classes excluding Rate Class M (Outdoor Lighting Service). The class revenue requirement target for Rate Class M was increased by the percentage difference between the current and proposed revenue requirement.

[4] The total Company proposed revenue requirement increase is 14.29%. Thus, the maximum class-share revenue increase is calculated as 1.2 x 14.29% = 17.15%.

4. Calculates the shortfall between the proposed revenue requirement and revenue targets (after the enforcement of the caps)
5. Allocates the shortfall to all rate classes with target revenues below the cap based on the pro rata share of revenues at current rates
6. Repeats steps 3-5 until no shortfall exists

Q How did Witness Heintz select these caps? Does the use of caps on revenue-increases comport with the principles of rate design that you described earlier?

A Witness Heintz established caps with consultation with the Company as a "reasonable variance." These caps are introduced to mitigate rate shocks and ensure that the bill stability principle is met. See Attachment SIS-2 (Data Response Staff 9-10).

Q Do you have any concerns with how Witness Heintz used the marginal cost study to determine the class revenue targets?

A No. Based on my review, Witness Heintz' use of the marginal cost study for determining the class revenue targets is appropriate and consistent with the widely accepted implementation practices in the industry.

V. REVIEW OF RATE DESIGN

Q What documents did you rely upon for your review?

A I reviewed the testimony of Company Witness Heintz, the testimony of Company Witnesses Greene and Simek regarding temporary rates as well as a subset of discovery responses related to rate design.

Q Please describe how Witness Heintz determined the rate components for each rate class.

A Witness Heintz calculated the individual rate components by 1) adopting the customer charge proposed in the temporary rate increase, which reflects a 5.28% increase relative to current rates, 2) increasing demand charges by the total percentage increase in revenue requirement between current and proposed rates, and 3) calculating an energy charge based on the anticipated revenue shortfall from the customer charge and demand charge.[5] To determine the revenue shortfall for each rate class, Witness Heintz subtracted the anticipated revenues from the customer and demand charges (if applicable) based on pro forma test year billing determinants from the class's revenue target. With the class shortfall calculated, Witness Heintz calculated the energy component of rates by dividing the shortfall by the pro forma test year energy quantity by class.

Q **Do the rates from Witness Heintz's testimony reflect pure marginal cost rates?**

A No. As described earlier, designing rates purely based on the marginal costs would lead to under recovery of the revenues in the Company's case. Therefore, marginal costs were adjusted using the equiproportional adjustment factor to ensure the recovery of the embedded costs. The resulting class revenue targets were also adjusted using the revenue increase caps to limit disproportionate rate shock to any given class. Moreover, within the rate class, rate components such as the customer charge and energy charge also do not reflect pure marginal cost-based price signals. Witness Heintz explains the deviation of the proposed customer charges from the marginal customer cost on the basis of rate continuity and the proposed revenue decoupling mechanism. See Attachment SIS-3 (Data Response Staff 9-11).

Q **You stated that the customer charges do not reflect pure marginal cost-based price signals. How do the proposed customer charges compare to the marginal cost-based customer charges for the residential classes?**

A If approved, the Rate D and Rate D-10 customer charges would increase from $14.02 to $14.76, while the marginal customer costs are $32.02 and $39.59, respectively. As indicated in Witness Heintz's direct testimony, "… MCOS clearly indicates that current fixed monthly rates are significantly below costs…"[6] Figure 1 shows the proposed

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[5] Witness Heintz says that the customer charge increased by the overall percentage increase for temporary rates. See Attachment SIS-3 (Data Response Staff 9-11). Witnesses Green and Simek's testimony, which sets the temporary rates, cites a 5.18% increase in distribution revenue, slightly less than the 5.28% increase to customer charges reflected in the numbers proposed by Witness Heintz. See Bates II-007, lines 17-19.

[6] See Bates II-309, lines 4-5.

customer charges relative to the customer charges based on Witness Bartos' MCO study for all customer classes (excluding Rate M).

Figure 1: Proposed vs Marginal Cost Customer Charges

	Rate D	Rate D-10	Rate G-1	Rate G-2	Rate G-3	Rate T	Rate V
Liberty Proposed	$14.02	$14.02	$365.24	$60.90	$14.02	$14.02	$14.02
Liberty MCOS	$32.02	$39.59	$87.57	$61.98	$47.26	$34.37	$37.27
Difference	*$18.00*	*$25.57*	*-$277.67*	*$1.08*	*$33.24*	*$20.35*	*$23.25*

Sources and Notes:
Figure relies on data from the Company's marginal cost model.

Q **Witness Heintz indicates in his testimony that the proposed customer charge increases were limited to the temporary rate increases, given the proposed revenue decoupling mechanism. Is the proposed decoupling mechanism an adequate substitute for cost-reflective rate design?**

A No, it is not. Full decoupling breaks the link between utilities sales and revenues, and allows the rates to be adjusted up or down to ensure that the utility earns its approved revenue requirement. Full decoupling does not investigate the cause of the gap between actual and allowed revenues, and adjusts for all potential factors such as economy, weather, and DSM initiatives. However, it is not intended to be a substitute for cost-reflective rate design.

Q **Do you see any potential unintended consequences of Witness Heintz's reliance on the decoupling mechanism for limiting proposed customer charge increases?**

A Yes, I do. If the revenue decoupling mechanism is approved, the Company will be made whole relative to its revenue requirement and becomes indifferent to the mechanism through which the costs are recovered. While the proposed approach results in rate continuity, it may lead to unintended cross subsidies and result in inequitable cost recovery. Due to the volumetric structure of current rates, distributed generation (DG) customers are able to bypass the portion of distribution costs recovered on a volumetric basis. As the penetration of DG resources increases, an increasing share of customers may be able to bypass paying for distribution charges. The bypass may result in a greater share of the distribution costs being collected through the decoupling mechanism, which has the effect of shifting costs to the non-DG customers. DG customers would be unable to bypass these costs if assessed through a fixed monthly customer charge. Designing cost reflective rates is a more equitable and efficient practice to recover class revenue requirements.

Q Are the rates designed by Witness Heintz cost-reflective?

A They are only partially cost-reflective to the extent that they reflect marginal cost based revenue allocation for the class as a whole. With the exception of Rates G-1 and G-2, customer charges are lower than those implied by the MCOS, leading to higher energy charges than those would be implied by the MCOS. These higher energy charges may lead to under consumption compared to the economically efficient levels and lead to a deadweight loss, which is essentially a welfare loss.

Q The rate structures for several classes include fixed and volumetric charges. Is this an economically efficient rate structure?

A Not necessarily, although the Company is currently limited in its metering capabilities to enable more efficient rate structures. The most efficient and cost-reflective rate is a three-part rate that combines:[7]

- A *fixed monthly charge* to recover the full costs of billing, metering and customer service.
- A *demand charge* for recovering distribution capacity costs.
- A *time-varying energy* charge for recovering energy costs. This could take one of many forms, such as a simple time-of-use rate, a critical-peak pricing rate, a variable-peak pricing rate, or a real-time pricing rate.

Q Turning to the customer impact of the proposed rates, did Witness Heintz develop a rate impact analysis?

A Yes, Witness Heintz developed a bill impact analysis that calculated customer impacts both on total bills and on distribution only bills. The total bill analysis includes base

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[7] For a detailed discussion, see Ahmad Faruqui, "Rate Design 3.0: Future of Rate Design," Public Utilities Fortnightly, May 2018 and Advanced Energy Economy, "Rate Design for a DER Future: Designing Rates to Better Integrate and Value Distributed Energy Resources," Jan 2018.

(distribution) rates, the energy service charge and additional riders. For all customer classes, excluding Rate D, Witness Heintz used 12 months of monthly data for each customer to calculate annual bills under the proposed rates and current rates.[8] For Rate D, Witness Heintz created usage (kWh) bins to evenly divide customers into 20 groups. Witness Heintz repeated this analysis for rates including the proposed step increase. See Attachment SIS-4 (Attachment DAH-8).

Q Please describe the impacts of the proposed rate increase on the varying rate groups.

A On a total bill basis, the bill impact for the rate classes with the largest customer counts produce rate increase ranges of:

- Residential (Rate D): 5.5% to 7.4% with an average of 6.5%,
- General Service (Rate G-3): 5.3% to 5.5% with an average of 5.4%.

The bill impact differences within a rate class are driven by a combination of heterogeneity in the class (e.g., different volumetric and demand usage) and the distribution of the revenue increase across the components of the bill (i.e., customer, demand, and volumetric). If, for example, a class is homogenous with little variation in the total usage or demand requirements, then the impact of a rate increase would produce similar bill impacts regardless of whether the rate increase was implemented through a customer charge or volumetric charge. However, if a class is heterogeneous with one group of users with low volumetric usage of the system and a second group with high volumetric usage, implementing the rate increase through either the customer charge or the volumetric charge would create different bill impacts (i.e., a higher customer charge would disproportionately affect the bills of low usage customers while a higher volumetric charge would disproportionately affect high usage customers).

Figure 2 shows the total bill impact analysis for each rate class including the median impact and range of impacts. For each rate class, the middle of the "box" shows the median impact on customers (i.e., 50% of impacts are above the median and 50% are

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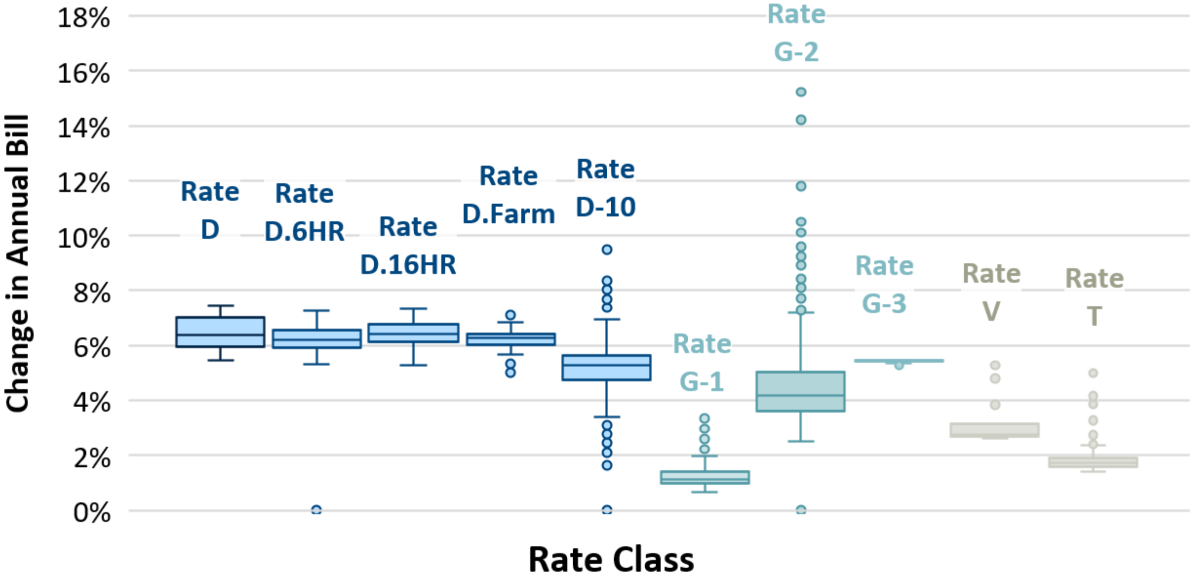
[8] Current rates refers to the most recently approved permanent base rates. Current rates do not reflect the temporary rate increase.

below). The ends of the box show the range in the first quartile above and below the average (i.e., the middle 50% of all bill impacts are within the box), and the edges of the whiskers show the range (excluding outliers).[9] Note that because Witness Heintz did not provide the customer-level data for the residential (Rate D) class, the charts and statistics below will underestimate the variability in this class.

As shown in Figure 2, the highest overall total bill impacts are generally within the residential rate classes, while the largest range of bill impacts is within Rate G-2. The total bill impacts for the residential rate classes ranges between 5% and 7%, with the exception of the of Rate D-10 (optional peak/off peak pricing) with bill impacts ranging from 2% to 10%.

Figure 2: Total Bill Impact of Proposed Rate Increase Relative to Current Rates



Sources and Notes:
Figure relies on data from the Company's marginal cost model. Zeros values on chart reflect missing values from underlying data, and do not represent customers with no change in bill. Rate G-2 analysis as presented by Witness Heintz did not include the formula to calculate customer charges for all customers. Analysis was modified to include the formula for customer charge for all G-2 customers. No other modifications were made to the underlying analysis.

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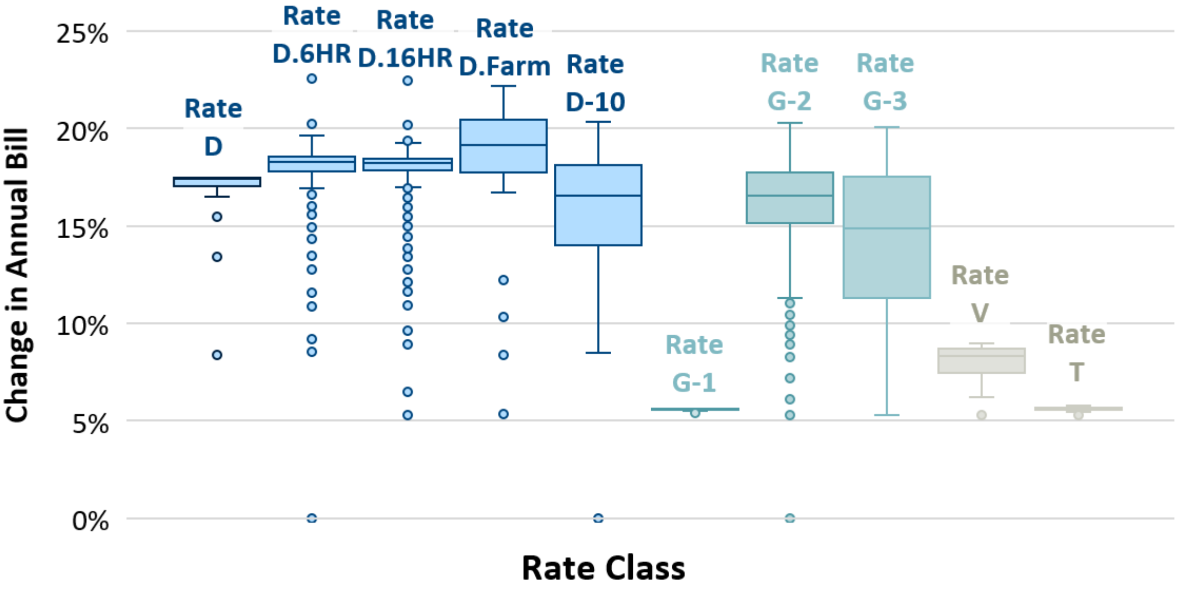
[9] As shown in Figure 1, outliers are those entries more than 1.5 above or below the inner quartile range.

The base rate bill impact of the proposed rate increase, presented in Figure 3, shows that the largest bill impacts are in the residential and general service rate classes, excluding Rate G-1. This comports with the total changes in targeted class revenues, which increase 17.2% for Rates D and G-3, 17.3% for Rate G-2, and less for Rates G-1 (5.7%), T (5.7%) and V (8.6%).[10] The variability of impacts within the groups is due to the heterogeneity of the group and the allocation of the rate increase between the different charge types for each rate class. Rate G-1, for example, has a relatively small variability in the rate impact on the total bill. This is because the proposed customer fixed charge, and on- and off-peak variable charges increased in relative proportion to one another (5.3% fixed customer charge increase, and 5.4% and 5.3% on- and off-peak increase respectively). In contrast, the proposed customer charge for Rate G-2 increased 5.3%, the demand charge increased 17.3% and the energy component increased 44.4%.

Figure 3: Base Rate Bill Impact of Proposed Rate Increase Relative to Current Rates



Sources and Notes:

Figure relies on data from the Company's marginal cost model. Zeros values on chart reflect missing values from underlying data, and do not represent customers with no change in bill. Rate G-2 analysis as presented by Witness Heintz did not include the formula to calculate customer charges for all customers. Analysis was modified to include the formula for customer charge for all G-2 customers. No other modifications were made to the underlying analysis.

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[10] The G-2 class is able to increase slightly above the 120% cap based off of the revenues that it was allocated under Witness Heintz's approach.

Q If the median residential Rate D impact of the proposed rate increase is 17%, why is the median total bill impact only 6%?

A For the median Rate D customer, approximately 37% of the total annual bill currently results from base distribution rates with the remaining bill resulting from energy services (43%) and other trackers (20%). As shown in Figure 4, these percentages would remain relatively stable under the proposed rates with 40% of the total bill due to base distribution rate charges, 41% due to energy services, and 19% from other trackers.

Figure 4: Median Residential Bill by Charge Type

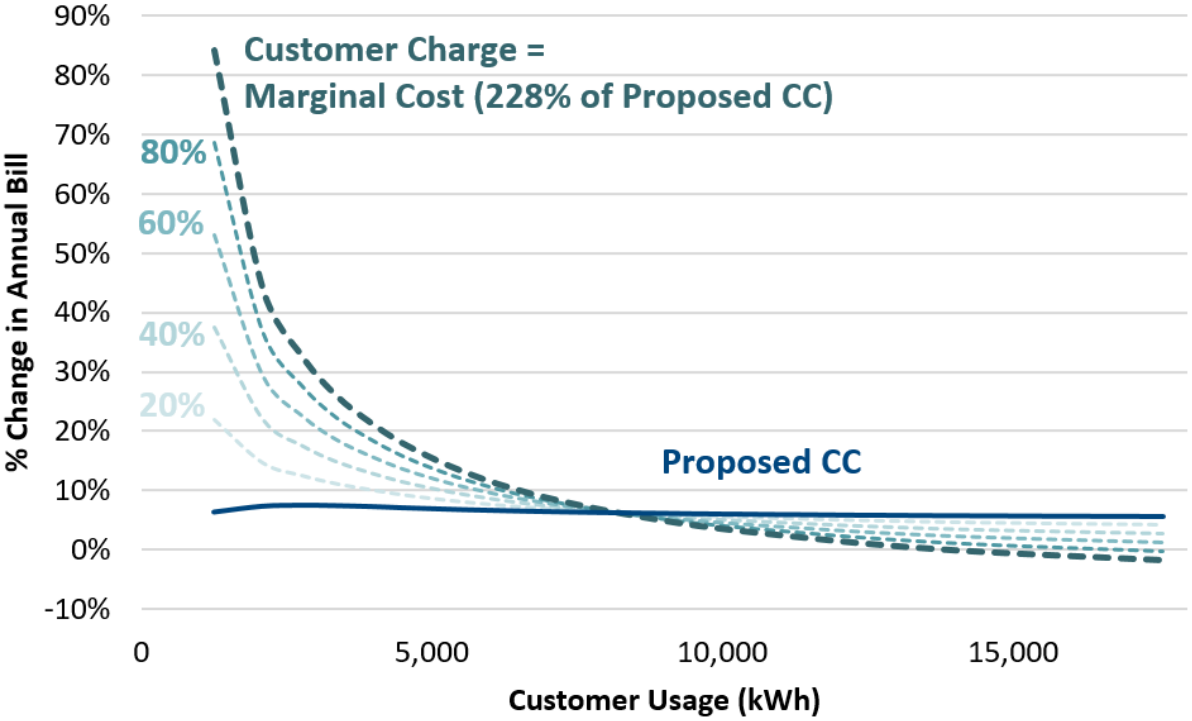
Rate Mechanism	Units	Current Rate Structure	Proposed Rate Structure	Median Customer Monthly Bill Current Rates	Median Customer Monthly Bill Proposed Rates
Base Rates					
Customer Charge	($/mo)	$14.02	$14.76	**$14.02**	**$14.76**
Energy Charge (1st 250 kWh)	($/kWh)	$0.04299	$0.05737	**$11**	**$14**
Energy Charge (over 250 kWh)	($/kWh)	$0.04883	$0.05737	**$16**	**$19**
Trackers					
Energy Services	($/kWh)	$0.08299	$0.08299	$48	$48
Other Trackers	($/kWh)	$0.03900	$0.03900	$23	$23
Total Bill				$112	$119
% of Bill Base Rates				37%	40%
% of Bill Energy Services				43%	41%
% of Bill Other Trackers				20%	19%

Sources and Notes:
Figure relies on data from the Company's marginal cost model.
Median annual residential customer usage is 6,978 kWh (581.5 kWh per month).

Q Did you consider how changing the customer charge would impact the distribution of the Rate D total bill impact?

A Yes, for Rate D, I held the targeted class revenues constant and varied the customer charge between the proposed customer charge and the customer charge calculated in the MCOS study. On a total bill basis, increasing the customer charge an additional 20% toward the cost of service (relative to the proposed) would increase annual bills for the lowest usage customers (up to 2,076 kWh annually) between 15% and 22%, relative to current levels, as shown in Figure 5. At full marginal cost levels, total customer bills for the lowest usage customers would increase 44% to 84%, relative to current levels, and total bills for the highest usage customers (14,412 to 131,676 kWh) would range between a 2% and a 4% decrease.

Figure 5: Total Bill Impact of Varying the Customer Charge for Rate D

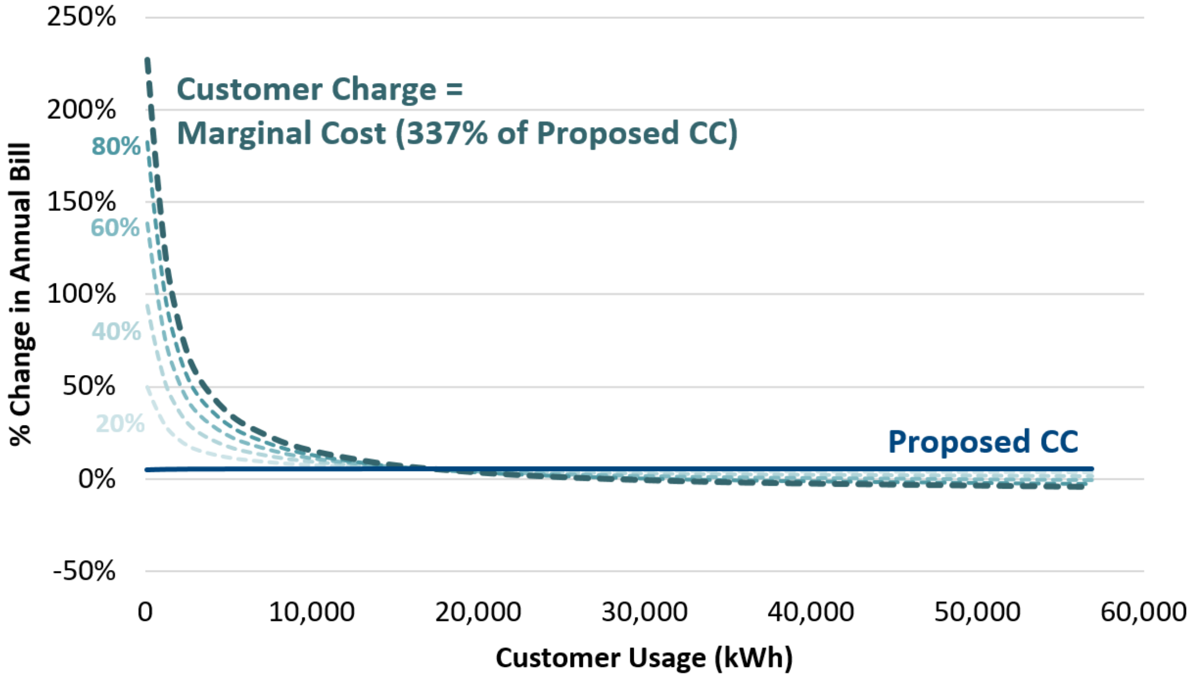


Sources and Notes:
Figure relies on data from the Company's marginal cost model.

Q Did you similarly consider how changing the customer charge would impact Rate G-3, for small general service customers?

A Yes, I repeated the same analysis for Rate G-3 to demonstrate how moving the customer charge closer to the customer charge in the marginal cost of survey study would impact customer bills. For this analysis, I held the proposed target class revenues constant and varied the customer charge to examine the impact on customer bills. As shown in Figure 6, increasing the customer charge 20% closer to the marginal cost of service study value would have an impact between 39% and 50% for the smallest 10% of Rate G-3 customers (up to 581 kWh annually). For the same customers, increasing the customer charge to the value derived from the marginal cost of service study would increase their bills 176% to 227%. Conversely, for the largest 10% of customers, setting the customer charge equal to the marginal cost of service would reduce annual bills 4.5% to 7.5%.

Figure 6: Total Bill Impact of Varying the Customer Charge for Rate G-3



Sources and Notes:
Figure relies on data from the Company's marginal cost model.

Q What are your conclusions based on your review 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 reasonable for all rate classes, with fairly tight distributions around the median.[11] 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 *Revenue Adequacy and Stability* (especially given the proposed revenue decoupling mechanism), *bill stability for customers* (given the small total bill impacts) and *customer satisfaction* (given the simple structure of the rates).

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[11] Rate G-2 class is an exception and has a larger variation around the median compared to the other rate classes due to the heterogeneous nature of the class, combined with disproportional adjustments to different rate components (customer charge, demand and energy charge).

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; mostly due to the prioritization of bill stability principle and limiting the increase in the customer charges. 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). Liberty Utilities has also proposed a time of use rate in their battery storage pilot (DE 17-189). Liberty Utilities-Gas was approved for decoupling in its last rate case (DG 17-048).

Q What are your conclusions based on your analysis of moving customer charges closer to values implied by the marginal cost study?

A This analysis has revealed that on a total bill basis, increasing the customer charge an additional 20% toward the cost of service (relative to the proposed) would increase annual bills for the lowest usage Rate D customers between 15% and 22%, relative to current levels. Similarly for the Rate G-3 customers, increasing the customer charge 20% closer to the marginal cost of service study value would have an impact between 39% and 50% for the smallest usage group. While the resulting total bill impact for G-3 customers is too high; residential bill impacts are more tolerable. This implies that there is potentially more room to increase customer charges for residential customers and bring them closer to the marginal customer costs.

Q What is your recommended increase for customer charges?

A Currently, proposed customer charge increase is 5.3% (or $0.74) relative to the current customer charge, for both Rate D and Rate G-3 customers. While there is no formula for what the increase should be, it is essential that the customer charges get closer to the levels implied by the marginal cost study over time. Based on the "50 States of Solar, Q4 2017 Quarterly Report," forty-one utilities in 25 states and DC filed new requests to increase residential fixed charges by at least 10% during 2017.[12] Overall, the median increase requested in 2017 was $4.80, with proposals ranging from $0.71 to $29.20. I recommend that Liberty increases its customer charges by 10% relative to the current customer charges, implying $1.40.

Q Witness Ros proposes modifications to Witness Bartos's MCOS study. Did you recalculate the class revenues allocations using the marginal cost values resulting from MCOS Witness Dr. Ros' analysis? Please explain.

A Yes, I did. Figure 7 below presents the class revenue allocations using the new marginal cost values calculated by Dr. Ros (See Attachment AJR-6). While Dr. Ros' proposed method results in lower marginal costs, the contribution of each class to the total target revenue requirement remains fairly constant after the implementation of the equiproportional allocation method, with the exception of Rate D (1.55 percentage point difference) and G-1 (-1.84 percentage point difference) classes. Once the rate caps are implemented, most class revenue allocations are the same or practically the same between Liberty and Brattle MCOS based allocations, with the exception of Rates G-1 and G-2. For these two classes, the differences are still fairly minimal and are 0.23 percentage point and -0.26 percentage point, respectively.

On the other hand, since the updated marginal cost values are significantly lower than Liberty proposed values, the marginal customer costs are also substantially lower. For

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[12] NC Clean Energy Technology Center, "50 States of Solar, Q4 2017 Quarterly Report," January 2018.

instance, updated marginal customer costs for Rate D and G-3 classes are $22.33 and $34.35, compared to $32.02 and $47.26 based on Liberty's marginal cost values.

Figure 7: Impact of Brattle MCOS Values

	Rate D	Rate D-10	Rate G-1	Rate G-2	Rate G-3	Rate M	Rate T	Rate V	Company Total
Marginal Cost Target Revenue Requirement									
Liberty MCOS	$22,768,108	$334,482	$8,623,563	$5,528,861	$6,390,155	$1,074,431	$703,241	$18,482	$45,441,322
Brattle MCOS	$23,471,527	$351,933	$7,787,631	$5,354,103	$6,656,640	$1,074,431	$726,281	$18,775	$45,441,322
Difference	*$703,419*	*$17,451*	*-$835,932*	*-$174,758*	*$266,486*	*$0*	*$23,041*	*$294*	*$0*
Marginal Cost Target Revenue Requirement Share									
Liberty MCOS	50.10%	0.74%	18.98%	12.17%	14.06%	2.36%	1.55%	0.04%	
Brattle MCOS	51.65%	0.77%	17.14%	11.78%	14.65%	2.36%	1.60%	0.04%	
Difference	*1.55%*	*0.04%*	*-1.84%*	*-0.38%*	*0.59%*	*0.00%*	*0.05%*	*0.00%*	
Target Revenue Requirement (Including 120% Cap)									
Liberty MCOS	$22,244,562	$332,528	$9,461,094	$5,808,988	$5,701,975	$1,074,431	$798,247	$19,497	$45,441,322
Brattle MCOS	$22,244,562	$332,528	$9,567,517	$5,693,079	$5,701,975	$1,074,431	$807,226	$20,005	$45,441,322
Difference	*$0*	*$0*	*$106,423*	*-$115,909*	*$0*	*$0*	*$8,979*	*$507*	*$0*
Target Revenue Requirement (Including 120% Cap) Share									
Liberty MCOS	48.95%	0.73%	20.82%	12.78%	12.55%	2.36%	1.76%	0.04%	
Brattle MCOS	48.95%	0.73%	21.05%	12.53%	12.55%	2.36%	1.78%	0.04%	
Difference	*0.00%*	*0.00%*	*0.23%*	*-0.26%*	*0.00%*	*0.00%*	*0.02%*	*0.00%*	
Customer Charge									
Liberty Proposed	$14.76	$14.76	$384.52	$64.11	$14.76	N/A	$14.76	$14.76	N/A
Liberty MCOS	$32.02	$39.59	$87.57	$61.98	$47.26	N/A	$34.37	$37.27	N/A
Brattle MCOS	$22.33	$28.29	$63.60	$44.67	$34.35	N/A	$24.20	$26.48	N/A
Liberty MCOS Difference	*$17.26*	*$24.83*	*-$296.95*	*-$2.14*	*$32.50*	*N/A*	*$19.61*	*$22.51*	*N/A*
Brattle MCOS Difference	*$7.57*	*$13.53*	*-$320.92*	*-$19.44*	*$19.59*	*N/A*	*$9.44*	*$11.72*	*N/A*

Sources and Notes:

Figure relies on data from the Company's marginal cost model.
The marginal cost target revenue requirements reflect the marginal cost estimates increased by the equiproportional adjustment factor. The Brattle MCOS numbers have been scaled to attain an equal company total target revenue requirement.

Q Does this update affect your conclusions stated earlier?

A No, it doesn't. While the gap between the current customer charges and customer costs from the marginal cost study declines, the current customer charge is still lower by $7.57 to $19.59, depending on the rate class. Therefore, I still recommend a 10% increase in customer charges relative to the current rates for Rate D and G-3 classes.

Q In addition to rates for the existing classes, what did the Company propose for rates for electric vehicles?

A The Company proposed to use the same time of use ("TOU") rates that were approved in Docket DE 17-189 as part of the Company's battery storage pilot. The TOU rates are seasonal and involve three periods: critical peak, on-peak and off-peak. The TOU rate covers energy, distribution and transmission rates.

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 related 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 **What do you recommend regarding the Company's proposed electric vehicle rates?**

A Because the PUC is going to consider and determine the appropriate rate design for electric vehicle charging, including the use of TOU 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 **What are your recommendations regarding the rate design proposed by Liberty?**

A I have three main recommendations:

- The Company should 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 consider further increasing the customer charges for the residential class, instead of relying on the revenue decoupling for the recovery of the fixed costs. I recommend 10% increase relative to the current customer charges for rate D and G-3 classes in this rate case, with the goal of closing the gap with marginal customer costs in the future.
- 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 **Does this conclude your testimony?**

A Yes.

SANEM I. SERGICI

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,

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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.

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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.

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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.

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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.

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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.

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

DE 19-064
Distribution Service Rate Case

Staff Data Requests - Set 9

Date Request Received: 9/26/19	Date of Response: 10/10/19
Request No. Staff 9-10	Respondent: David A. Heintz

REQUEST:

Reference Heintz Testimony. Refer to Bates pp. II-306 and II-307. Explain how you developed the rate continuity cap, and how this cap compares to those used in other rate design efforts.

RESPONSE:

The rate continuity cap was established in consultation with the Company as a reasonable variance from the average distribution rate increase sought in the instant proceeding. Rate continuity caps are common in many jurisdictions, and employed by many rate design analysts as a means of promoting efficiency and allowing movement in rates towards their costs to serve that class. This approach was also used in Liberty's EnergyNorth Natural Gas utility rate case in Docket No. DG 17-048.

Docket No. DE 19-064
Exhibit 26
Attachment SIS-3

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

DE 19-064
Distribution Service Rate Case

Staff Data Requests - Set 9

Date Request Received: 9/26/19	Date of Response: 10/10/19
Request No. Staff 9-11	Respondent: David A. Heintz

REQUEST:

Reference Testimony of Heintz, Bates II-308: Please explain in detail the reasoning behind Liberty's proposal to increase the customer charges for Rates D, D-10, G-1, G-2, G-3, T, and V by the Company's proposed percentage increase in temporary rates.

RESPONSE:

The fixed charges were increased by the overall percentage increase for temporary rates in an effort to promote rate continuity. This is similar to the approach employed in the EnergyNorth rate case, Docket No. DG 17-048. The reasoning was to establish a test year rate design updated for the new test year costs and billing determinants, thus establishing a base line upon which to design rates that can now also consider the implementation of revenue decoupling. See also Bates II-309, lines 1–13 regarding the influence of decoupling on rate design.

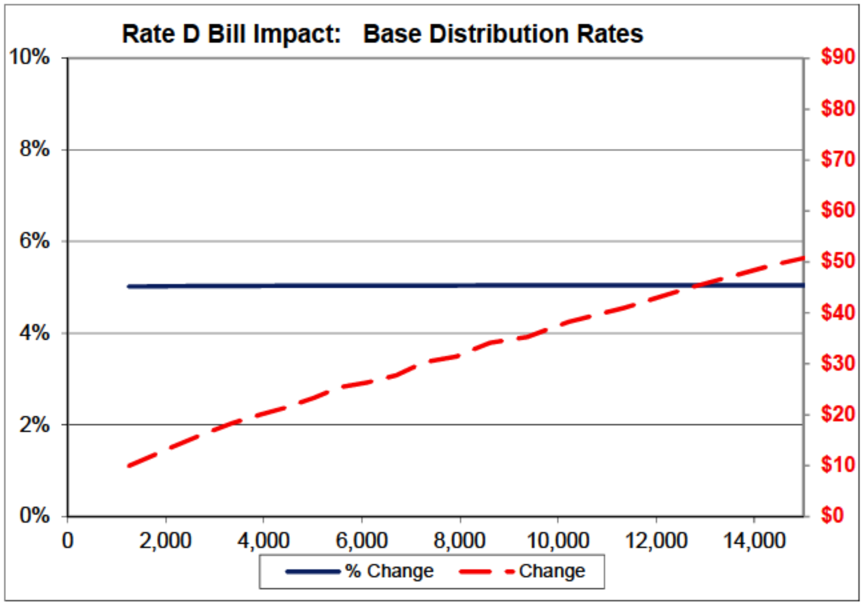
COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE

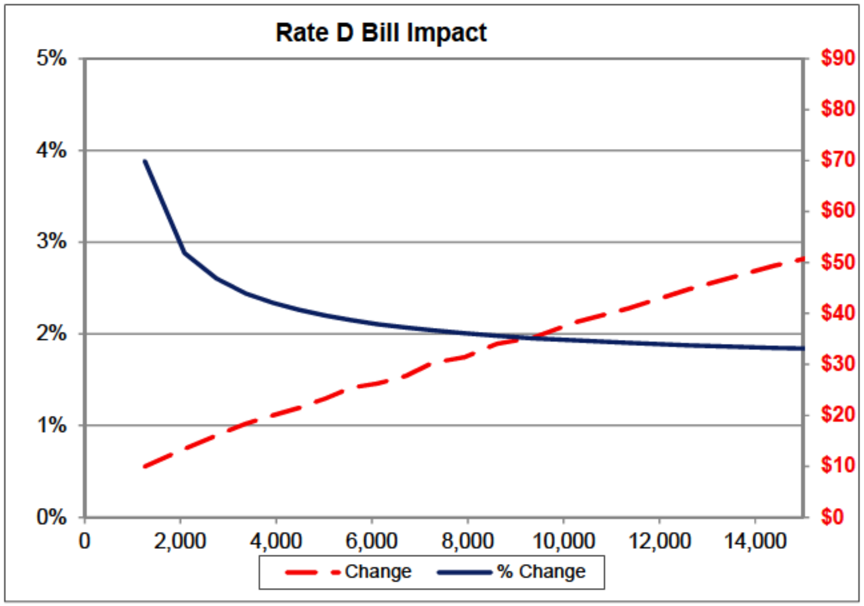
D Proposed Permanent Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027

D Proposed Permanent Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE

Line				
1	**D Proposed Permanent Rates**		**D Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03900	Other Tracking Mechanisms	$0.03900
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7				
8	First 250 kWh	$0.05737	First 250 kWh	$0.06027
9	Excess 250 kWh	$0.05737	Excess 250 kWh	$0.06027

	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	1,248	$198.32	$208.27	$9.95	5.0%	$256.19	$266.14	$9.95	3.9%	1,733	1,733	5.0%
11	1,260	2,076	$267.26	$280.69	$13.44	5.0%	$465.77	$479.21	$13.44	2.9%	1,748	3,481	10.0%
12	2,088	2,760	$320.87	$337.02	$16.15	5.0%	$620.61	$636.75	$16.15	2.6%	1,728	5,209	15.0%
13	2,772	3,348	$364.41	$382.75	$18.34	5.0%	$750.76	$769.11	$18.34	2.4%	1,741	6,950	20.0%
14	3,360	3,936	$398.41	$418.47	$20.06	5.0%	$858.08	$878.14	$20.06	2.3%	1,710	8,660	25.0%
15	3,948	4,476	$426.35	$447.82	$21.48	5.0%	$949.97	$971.44	$21.48	2.3%	1,740	10,400	30.0%
16	4,488	5,028	$463.26	$486.60	$23.34	5.0%	$1,061.28	$1,084.62	$23.34	2.2%	1,726	12,126	35.0%
17	5,040	5,556	$505.20	$530.66	$25.46	5.0%	$1,184.44	$1,209.90	$25.46	2.1%	1,732	13,858	39.9%
18	5,568	6,108	$521.53	$547.82	$26.29	5.0%	$1,248.05	$1,274.34	$26.29	2.1%	1,749	15,607	45.0%
19	6,120	6,684	$549.87	$577.59	$27.72	5.0%	$1,339.80	$1,367.52	$27.72	2.1%	1,754	17,361	50.0%
20	6,696	7,272	$602.18	$632.54	$30.36	5.0%	$1,490.40	$1,520.76	$30.36	2.0%	1,719	19,080	55.0%
21	7,284	7,920	$623.14	$654.57	$31.42	5.0%	$1,565.63	$1,597.06	$31.42	2.0%	1,736	20,816	60.0%
22	7,932	8,604	$675.72	$709.80	$34.08	5.0%	$1,721.33	$1,755.41	$34.08	2.0%	1,731	22,547	65.0%
23	8,616	9,360	$699.00	$734.26	$35.26	5.0%	$1,805.89	$1,841.15	$35.26	2.0%	1,746	24,293	70.0%
24	9,372	10,212	$757.69	$795.92	$38.23	5.0%	$1,981.74	$2,019.97	$38.23	1.9%	1,729	26,022	75.0%
25	10,224	11,340	$811.95	$852.92	$40.97	5.0%	$2,153.38	$2,194.35	$40.97	1.9%	1,740	27,762	80.0%
26	11,352	12,624	$887.14	$931.91	$44.77	5.0%	$2,387.25	$2,432.02	$44.77	1.9%	1,734	29,496	85.0%
27	12,636	14,400	$979.01	$1,028.42	$49.41	5.0%	$2,674.25	$2,723.66	$49.41	1.8%	1,726	31,222	90.0%
28	14,412	17,580	$1,116.00	$1,172.34	$56.34	5.0%	$3,104.09	$3,160.43	$56.34	1.8%	1,738	32,960	95.0%
29	17,592	131,676	$1,543.81	$1,621.77	$77.96	5.1%	$4,443.22	$4,521.19	$77.96	1.8%	1,734	34,694	100.0%

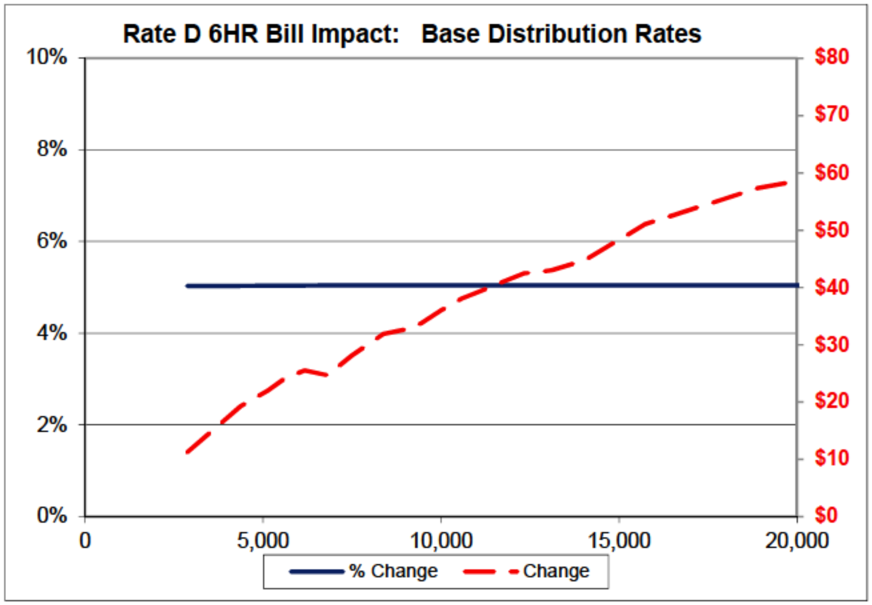
COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 6 Hour Control

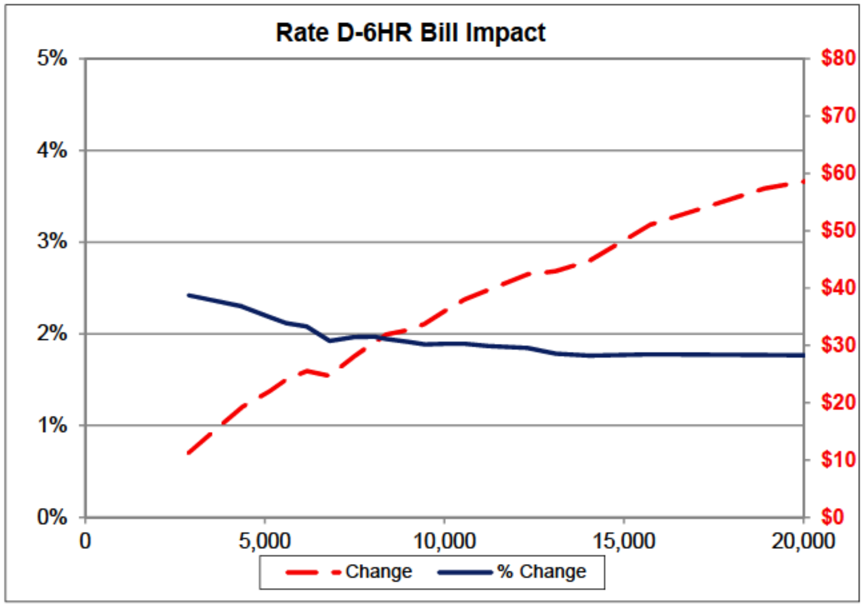
D Proposed Permanent Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
Off Peak Use	$0.05043
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
Off Peak Use	$0.05298
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027

D Proposed Permanent Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
Off Peak Use	$0.05043
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
Off Peak Use	$0.05298
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 6 Hour Control

Line				
1	**D Proposed Permanent Rates**		**D Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03900	Other Tracking Mechanisms	$0.03900
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7	Off Peak Use	$0.05043	Off Peak Use	$0.05298
8	First 250 kWh	$0.05737	First 250 kWh	$0.06027
9	Excess 250 kWh	$0.05737	Excess 250 kWh	$0.06027

	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	2,869	$223.08	$234.31	$11.23	5.0%	$463.70	$474.93	$11.23	2.4%	12	12	4.6%
11	2,869	4,355	$381.89	$401.12	$19.23	5.0%	$836.01	$855.25	$19.23	2.3%	13	25	9.5%
12	4,355	5,131	$436.30	$458.28	$21.98	5.0%	$1,006.46	$1,028.44	$21.98	2.2%	13	38	14.5%
13	5,131	5,614	$479.05	$503.20	$24.14	5.0%	$1,142.17	$1,166.32	$24.14	2.1%	13	51	19.5%
14	5,614	6,162	$506.44	$531.97	$25.53	5.0%	$1,228.04	$1,253.57	$25.53	2.1%	13	64	24.4%
15	6,162	6,802	$489.74	$514.44	$24.70	5.0%	$1,284.88	$1,309.59	$24.70	1.9%	13	77	29.4%
16	6,802	7,480	$557.39	$585.50	$28.11	5.0%	$1,430.08	$1,458.19	$28.11	2.0%	14	91	34.7%
17	7,480	8,054	$605.68	$636.22	$30.55	5.0%	$1,550.37	$1,580.91	$30.55	2.0%	13	104	39.7%
18	8,054	8,377	$632.16	$664.05	$31.88	5.0%	$1,638.95	$1,670.83	$31.88	1.9%	13	117	44.7%
19	8,377	8,985	$647.79	$680.47	$32.68	5.0%	$1,707.84	$1,740.52	$32.68	1.9%	13	130	49.6%
20	8,985	9,454	$670.06	$703.87	$33.81	5.0%	$1,795.23	$1,829.04	$33.81	1.9%	13	143	54.6%
21	9,454	10,019	$714.51	$750.56	$36.05	5.0%	$1,905.77	$1,941.82	$36.05	1.9%	13	156	59.5%
22	10,019	10,566	$753.76	$791.79	$38.03	5.0%	$2,010.85	$2,048.88	$38.03	1.9%	13	169	64.5%
23	10,566	11,214	$786.15	$825.82	$39.67	5.0%	$2,125.27	$2,164.94	$39.67	1.9%	14	183	69.8%
24	11,214	12,308	$840.52	$882.94	$42.42	5.0%	$2,297.19	$2,339.60	$42.42	1.8%	13	196	74.8%
25	12,308	13,102	$851.28	$894.25	$42.97	5.0%	$2,410.97	$2,453.94	$42.97	1.8%	13	209	79.8%
26	13,102	14,045	$887.00	$931.78	$44.78	5.0%	$2,541.80	$2,586.58	$44.78	1.8%	13	222	84.7%
27	14,045	15,727	$1,010.80	$1,061.83	$51.03	5.0%	$2,869.95	$2,920.99	$51.03	1.8%	13	235	89.7%
28	15,727	18,902	$1,136.12	$1,193.48	$57.36	5.0%	$3,238.65	$3,296.01	$57.36	1.8%	13	248	94.7%
29	18,902	34,757	$1,483.47	$1,558.40	$74.92	5.1%	$4,370.17	$4,445.09	$74.92	1.7%	14	262	100.0%

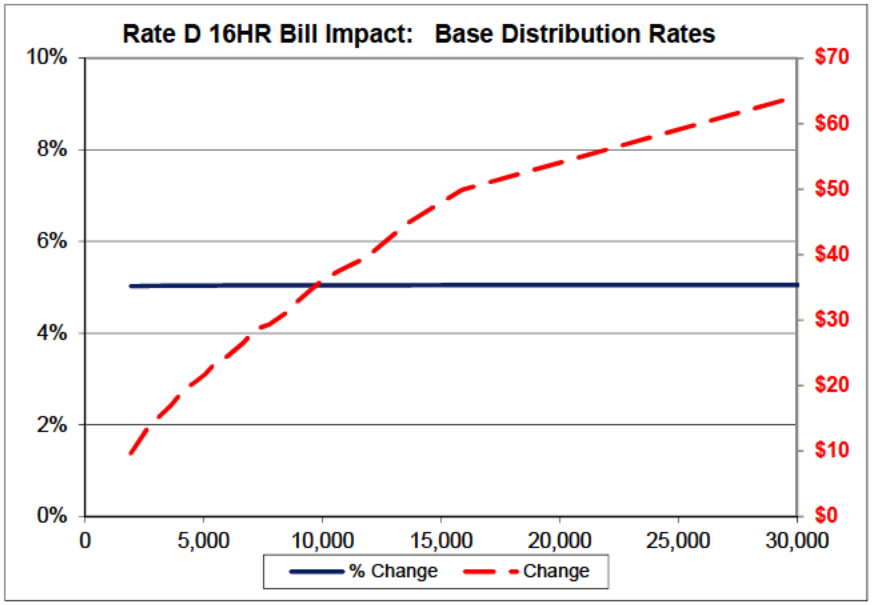
COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 16 Hour Control

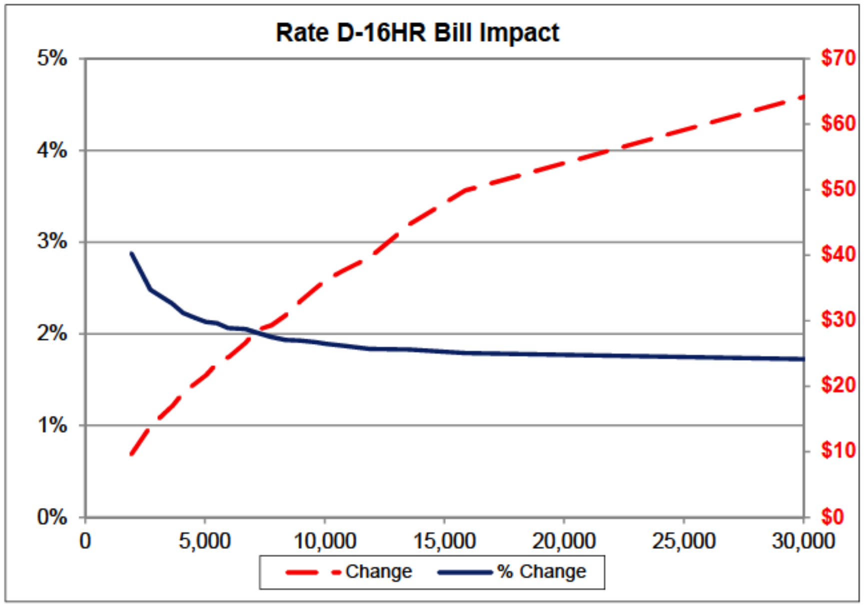
D Proposed Permanent Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
Off Peak Use	$0.04951
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
Off Peak Use	$0.05202
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027

D Proposed Permanent Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
Off Peak Use	$0.04951
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
Off Peak Use	$0.05202
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 16 Hour Control

Line				
1	**D Proposed Permanent Rates**		**D Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03900	Other Tracking Mechanisms	$0.03900
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7	Off Peak Use	$0.04951	Off Peak Use	$0.05202
8	First 250 kWh	$0.05737	First 250 kWh	$0.06027
9	Excess 250 kWh	$0.05737	Excess 250 kWh	$0.06027

	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	1,921	$191.36	$200.99	$9.62	5.0%	$334.36	$343.99	$9.62	2.9%	22	22	4.7%
11	1,921	2,715	$275.71	$289.59	$13.88	5.0%	$559.22	$573.10	$13.88	2.5%	23	45	9.6%
12	2,715	3,614	$336.90	$353.87	$16.97	5.0%	$727.70	$744.67	$16.97	2.3%	24	69	14.7%
13	3,614	4,072	$377.19	$396.19	$19.01	5.0%	$852.52	$871.53	$19.01	2.2%	23	92	19.7%
14	4,072	4,600	$405.98	$426.45	$20.47	5.0%	$940.39	$960.85	$20.47	2.2%	24	116	24.8%
15	4,600	5,067	$432.48	$454.28	$21.80	5.0%	$1,024.37	$1,046.17	$21.80	2.1%	23	139	29.7%
16	5,067	5,512	$468.05	$491.65	$23.60	5.0%	$1,116.35	$1,139.95	$23.60	2.1%	24	163	34.8%
17	5,512	5,988	$485.32	$509.79	$24.48	5.0%	$1,185.66	$1,210.13	$24.48	2.1%	23	186	39.7%
18	5,988	6,685	$528.23	$554.87	$26.64	5.0%	$1,298.97	$1,325.61	$26.64	2.1%	24	210	44.9%
19	6,685	7,185	$567.73	$596.36	$28.64	5.0%	$1,425.18	$1,453.81	$28.64	2.0%	23	233	49.8%
20	7,185	7,770	$581.52	$610.86	$29.34	5.0%	$1,494.07	$1,523.41	$29.34	2.0%	23	256	54.7%
21	7,770	8,358	$610.79	$641.62	$30.82	5.0%	$1,592.88	$1,623.70	$30.82	1.9%	24	280	59.8%
22	8,358	8,965	$652.81	$685.75	$32.94	5.0%	$1,710.64	$1,743.58	$32.94	1.9%	23	303	64.7%
23	8,965	9,621	$693.04	$728.02	$34.98	5.0%	$1,833.43	$1,868.41	$34.98	1.9%	24	327	69.9%
24	9,621	10,026	$716.34	$752.50	$36.16	5.0%	$1,913.11	$1,949.27	$36.16	1.9%	23	350	74.8%
25	10,026	10,750	$745.49	$783.13	$37.63	5.0%	$2,012.13	$2,049.77	$37.63	1.9%	24	374	79.9%
26	10,750	11,866	$784.84	$824.47	$39.63	5.0%	$2,156.73	$2,196.36	$39.63	1.8%	23	397	84.8%
27	11,866	13,530	$885.41	$930.11	$44.71	5.0%	$2,444.57	$2,489.28	$44.71	1.8%	24	421	90.0%
28	13,530	15,874	$987.90	$1,037.80	$49.90	5.1%	$2,786.64	$2,836.54	$49.90	1.8%	23	444	94.9%
29	15,874	30,062	$1,271.21	$1,335.45	$64.24	5.1%	$3,722.66	$3,786.90	$64.24	1.7%	24	468	100.0%

COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE - Farm Use

D Proposed Permanent Rates

Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
Farm Use	$0.05413
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates

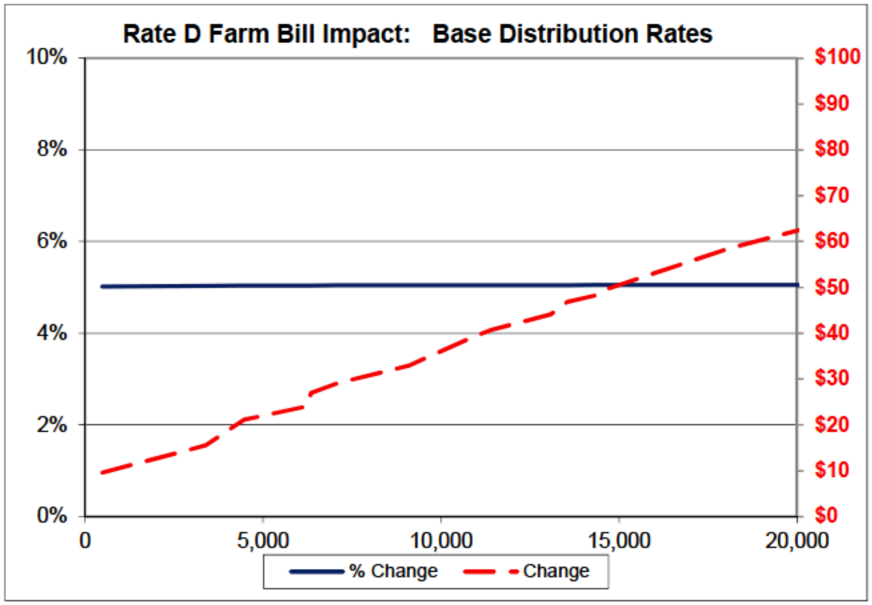
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
Farm Use	$0.05687
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027

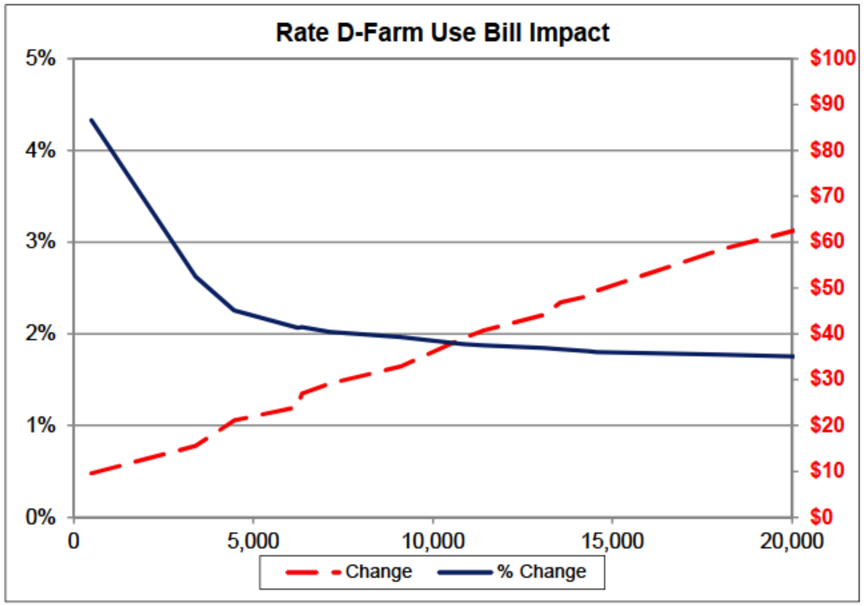
D Proposed Permanent Rates

Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$14.76
Farm Use	$0.05413
First 250 kWh	$0.05737
Excess 250 kWh	$0.05737

D Proposed Step Adj. Rates

Energy Services	$0.00000
Other Tracking Mechanisms	$0.03900
Customer charge	$15.50
Farm Use	$0.05687
First 250 kWh	$0.06027
Excess 250 kWh	$0.06027





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D : DOMESTIC SERVICE - Farm Use

Line				
1	**D Proposed Permanent Rates**		**D Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03900	Other Tracking Mechanisms	$0.03900
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7	Farm Use	$0.05413	Farm Use	$0.05687
8	First 250 kWh	$0.05737	First 250 kWh	$0.06027
9	Excess 250 kWh	$0.05737	Excess 250 kWh	$0.06027

	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	487	$191.43	$201.03	$9.60	5.0%	$221.87	$231.47	$9.60	4.3%	2	2	3.6%
11	487	3,385	$309.30	$324.86	$15.56	5.0%	$591.99	$607.55	$15.56	2.6%	3	5	9.1%
12	3,385	4,472	$419.62	$440.76	$21.14	5.0%	$937.38	$958.52	$21.14	2.3%	3	8	14.5%
13	4,472	6,235	$477.21	$501.27	$24.06	5.0%	$1,163.81	$1,187.87	$24.06	2.1%	3	11	20.0%
14	6,235	6,348	$536.22	$563.26	$27.03	5.0%	$1,304.39	$1,331.43	$27.03	2.1%	2	13	23.6%
15	6,348	7,125	$579.08	$608.29	$29.20	5.0%	$1,444.64	$1,473.85	$29.20	2.0%	3	16	29.1%
16	7,125	9,093	$652.35	$685.26	$32.91	5.0%	$1,674.87	$1,707.78	$32.91	2.0%	3	19	34.5%
17	9,093	10,838	$773.67	$812.72	$39.05	5.0%	$2,068.31	$2,107.36	$39.05	1.9%	3	22	40.0%
18	10,838	11,409	$807.81	$848.59	$40.77	5.0%	$2,174.46	$2,215.24	$40.77	1.9%	2	24	43.6%
19	11,409	13,076	$874.28	$918.42	$44.14	5.0%	$2,389.39	$2,433.53	$44.14	1.8%	3	27	49.1%
20	13,076	13,545	$927.19	$974.00	$46.81	5.0%	$2,556.28	$2,603.10	$46.81	1.8%	3	30	54.5%
21	13,545	14,316	$955.52	$1,003.78	$48.26	5.1%	$2,666.19	$2,714.44	$48.26	1.8%	3	33	60.0%
22	14,316	14,558	$978.40	$1,027.82	$49.42	5.1%	$2,742.92	$2,792.34	$49.42	1.8%	2	35	63.6%
23	14,558	18,073	$1,158.65	$1,217.18	$58.53	5.1%	$3,301.45	$3,359.98	$58.53	1.8%	3	38	69.1%
24	18,073	21,246	$1,284.79	$1,349.70	$64.92	5.1%	$3,724.51	$3,789.42	$64.92	1.7%	3	41	74.5%
25	21,246	26,756	$1,632.92	$1,715.45	$82.53	5.1%	$4,843.25	$4,925.78	$82.53	1.7%	3	44	80.0%
26	26,756	35,641	$1,983.25	$2,083.53	$100.28	5.1%	$6,007.70	$6,107.98	$100.28	1.7%	2	46	83.6%
27	35,641	50,091	$2,636.25	$2,769.57	$133.32	5.1%	$8,105.22	$8,238.54	$133.32	1.6%	3	49	89.1%
28	50,091	132,674	$4,921.17	$5,170.15	$248.98	5.1%	$15,552.03	$15,801.01	$248.98	1.6%	3	52	94.5%
29	132,674	722,508	$19,962.72	$20,972.11	$1,009.39	5.1%	$62,706.35	$63,715.74	$1,009.39	1.6%	3	55	100.0%

COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D-10 : DOMESTIC SERVICE Optional Peak Load Pricing

D10 Proposed Permanent Rates

Energy Services	$0.08299
Other Tracking Mechanisms	$0.03505
Customer charge	$14.76
Peak kWh	$0.12200
Off Peak kWh	$0.00169

D10 Proposed Step Adj. Rates

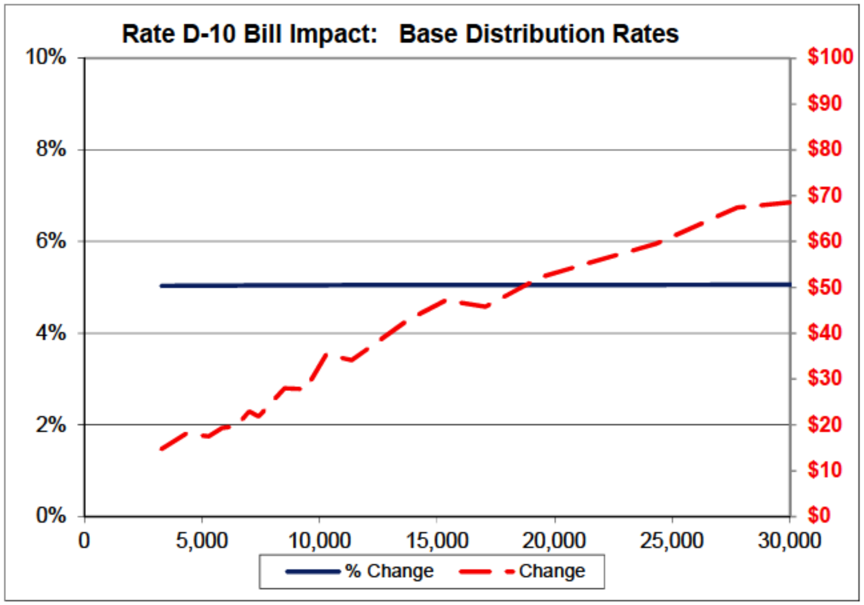
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03505
Customer charge	$15.50
Peak kWh	$0.12817
Off Peak kWh	$0.00178

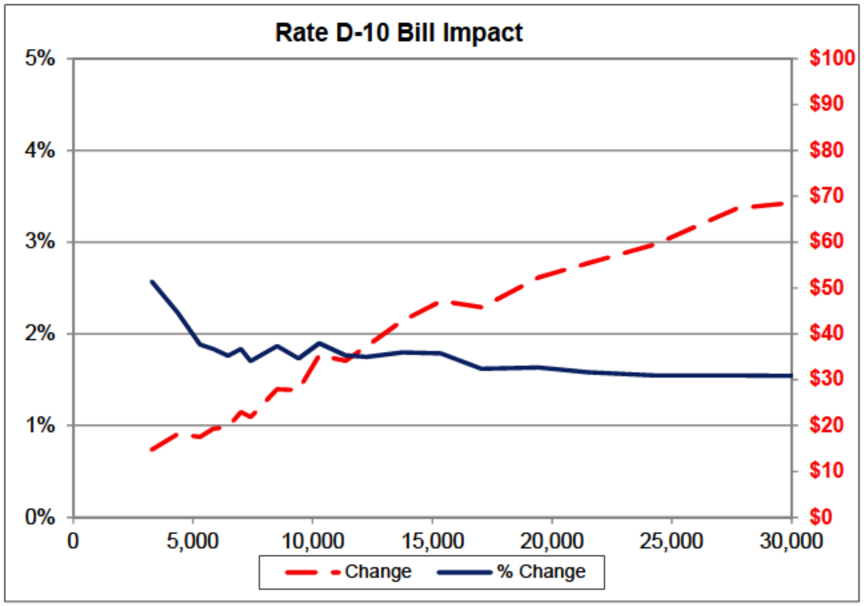
D10 Proposed Permanent Rates

Energy Services	$0.00000
Other Tracking Mechanisms	$0.03505
Customer charge	$14.76
Peak kWh	$0.12200
Off Peak kWh	$0.00169

D10 Proposed Step Adj. Rates

Energy Services	$0.00000
Other Tracking Mechanisms	$0.03505
Customer charge	$15.50
Peak kWh	$0.12817
Off Peak kWh	$0.00178





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE D-10 : DOMESTIC SERVICE Optional Peak Load Pricing

Line				
1	**D10 Proposed Permanent Rates**		**D10 Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03505	Other Tracking Mechanisms	$0.03505
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7				
8	Peak kWh	$0.12200	Peak kWh	$0.12817
9	Off Peak kWh	$0.00169	Off Peak kWh	$0.00178

	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	3,272	$293.12	$307.88	$14.76	5.0%	$573.89	$588.65	$14.76	2.6%	20	20	4.6%
11	3,272	4,337	$359.63	$377.75	$18.12	5.0%	$809.84	$827.96	$18.12	2.2%	22	42	9.6%
12	4,337	5,290	$347.23	$364.73	$17.50	5.0%	$928.05	$945.55	$17.50	1.9%	22	64	14.7%
13	5,290	5,859	$383.41	$402.74	$19.33	5.0%	$1,053.65	$1,072.98	$19.33	1.8%	22	86	19.7%
14	5,859	6,467	$391.25	$410.98	$19.73	5.0%	$1,120.18	$1,139.91	$19.73	1.8%	22	108	24.8%
15	6,467	7,006	$455.15	$478.11	$22.96	5.0%	$1,251.35	$1,274.31	$22.96	1.8%	22	130	29.8%
16	7,006	7,408	$433.47	$455.34	$21.87	5.0%	$1,283.05	$1,304.92	$21.87	1.7%	21	151	34.6%
17	7,408	8,506	$553.77	$581.72	$27.95	5.0%	$1,498.17	$1,526.12	$27.95	1.9%	22	173	39.7%
18	8,506	9,408	$550.06	$577.83	$27.77	5.0%	$1,605.54	$1,633.31	$27.77	1.7%	22	195	44.7%
19	9,408	10,276	$700.15	$735.51	$35.36	5.0%	$1,862.03	$1,897.38	$35.36	1.9%	22	217	49.8%
20	10,276	11,375	$676.42	$710.58	$34.16	5.1%	$1,932.79	$1,966.95	$34.16	1.8%	22	239	54.8%
21	11,375	12,247	$739.42	$776.77	$37.35	5.1%	$2,137.57	$2,174.93	$37.35	1.7%	22	261	59.9%
22	12,247	13,747	$847.77	$890.60	$42.83	5.1%	$2,383.96	$2,426.79	$42.83	1.8%	22	283	64.9%
23	13,747	15,366	$933.73	$980.91	$47.18	5.1%	$2,639.73	$2,686.91	$47.18	1.8%	21	304	69.7%
24	15,366	17,055	$905.65	$951.43	$45.77	5.1%	$2,828.48	$2,874.25	$45.77	1.6%	22	326	74.8%
25	17,055	19,418	$1,034.52	$1,086.81	$52.29	5.1%	$3,202.34	$3,254.64	$52.29	1.6%	22	348	79.8%
26	19,418	21,508	$1,096.15	$1,151.57	$55.42	5.1%	$3,506.67	$3,562.09	$55.42	1.6%	22	370	84.9%
27	21,508	24,317	$1,178.03	$1,237.60	$59.57	5.1%	$3,856.37	$3,915.94	$59.57	1.5%	22	392	89.9%
28	24,317	27,759	$1,333.41	$1,400.84	$67.43	5.1%	$4,359.88	$4,427.31	$67.43	1.5%	22	414	95.0%
29	27,759	64,654	$1,702.65	$1,788.78	$86.13	5.1%	$5,819.97	$5,906.10	$86.13	1.5%	22	436	100.0%

COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE G-1: GENERAL SERVICE TIME-OF-USE

G-1 Proposed Permanent Rates

Energy Services	$0.07542
Other Tracking Mechanisms	$0.03201
Customer charge	$384.47
Demand Charge	$8.22
Peak kWh	$0.00528
Off Peak kWh	$0.00158

G-1 Proposed Step Adj. Rates

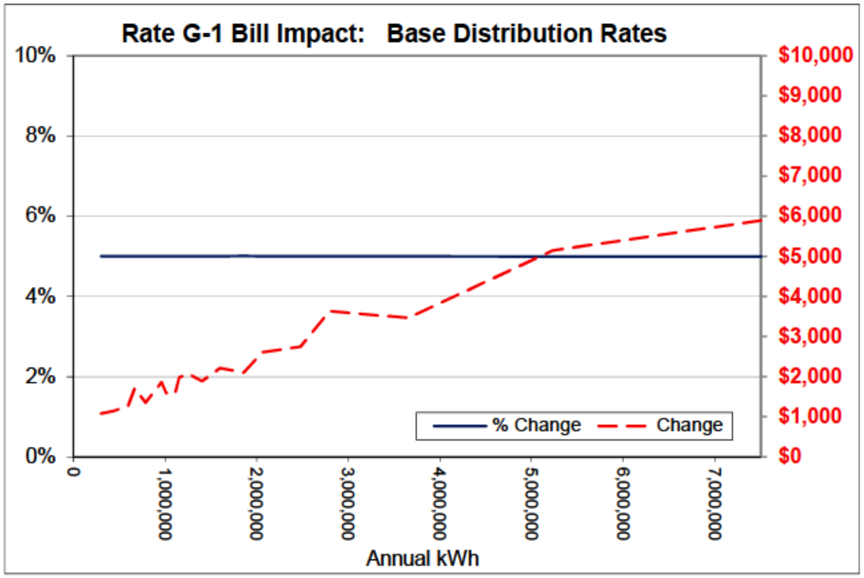
Energy Services	$0.07542
Other Tracking Mechanisms	$0.03201
Customer charge	$403.87
Demand Charge	$8.63
Peak kWh	$0.00555
Off Peak kWh	$0.00166

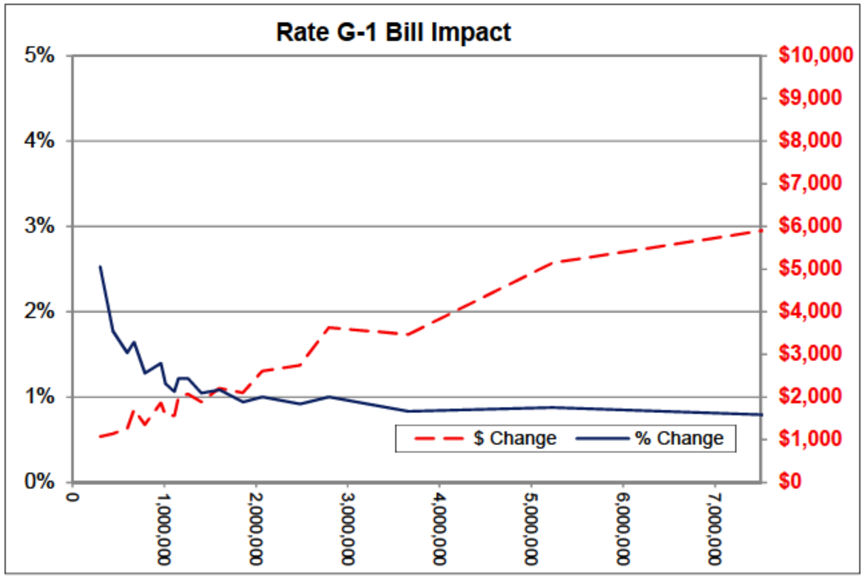
G-1 Proposed Permanent Rates

Energy Services	$0.00000
Other Tracking Mechanisms	$0.03201
Customer charge	$384.47
Peak kWh	$0.00528
Off Peak kWh	$0.00158

G-1 Proposed Step Adj. Rates

Energy Services	$0.00000
Other Tracking Mechanisms	$0.03201
Customer charge	$403.87
Peak kWh	$0.00555
Off Peak kWh	$0.00166





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE G-1: GENERAL SERVICE TIME-OF-USE

Line	**G-1 Proposed Permanent Rates**		**G-1 Proposed Step Adj. Rates**	
2	Energy Services	$0.07542	Energy Services	$0.07542
3	Other Tracking Mechanisms	$0.03201	Other Tracking Mechanisms	$0.03201
4				
5	Customer charge	$384.47	Customer charge	$403.87
6				
7	Demand chrge	$8.22	Demand charge	$8.63
8	Peak kWh	$0.00528	Peak kWh	$0.00555
9	Off Peak kWh	$0.00158	Off Peak kWh	$0.00166

	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges			Average Annual kWh	Average $ per kWh	
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers		Current Rates	Proposed Rates
10	0	299,386	$21,564	$22,643	$1,078	5.0%	$42,627	$43,705	$1,078	2.5%	6	6	4.4%	175,391	$0.1230	$0.1291
11	299,386	437,986	$22,822	$23,964	$1,142	5.0%	$64,373	$65,515	$1,142	1.8%	7	13	9.6%	366,979	$0.0622	$0.0653
12	437,986	595,428	$25,281	$26,547	$1,266	5.0%	$83,280	$84,546	$1,266	1.5%	7	20	14.8%	517,382	$0.0489	$0.0513
13	595,428	669,238	$34,261	$35,975	$1,714	5.0%	$104,225	$105,939	$1,714	1.6%	7	27	20.0%	640,708	$0.0535	$0.0561
14	669,238	787,986	$27,103	$28,459	$1,356	5.0%	$105,968	$107,324	$1,356	1.3%	6	33	24.4%	714,318	$0.0379	$0.0398
15	787,986	961,987	$37,233	$39,095	$1,862	5.0%	$133,499	$135,361	$1,862	1.4%	7	40	29.6%	871,224	$0.0427	$0.0449
16	961,987	1,011,107	$31,778	$33,369	$1,590	5.0%	$137,035	$138,626	$1,590	1.2%	7	47	34.8%	972,757	$0.0327	$0.0343
17	1,011,107	1,109,539	$31,269	$32,834	$1,565	5.0%	$146,802	$148,367	$1,565	1.1%	7	54	40.0%	1,061,363	$0.0295	$0.0309
18	1,109,539	1,153,487	$39,635	$41,618	$1,983	5.0%	$162,353	$164,337	$1,983	1.2%	6	60	44.4%	1,134,986	$0.0349	$0.0367
19	1,153,487	1,255,188	$41,436	$43,509	$2,074	5.0%	$169,933	$172,006	$2,074	1.2%	7	67	49.6%	1,181,570	$0.0351	$0.0368
20	1,255,188	1,400,986	$37,669	$39,555	$1,886	5.0%	$180,155	$182,041	$1,886	1.0%	7	74	54.8%	1,305,488	$0.0289	$0.0303
21	1,400,986	1,601,988	$44,151	$46,360	$2,210	5.0%	$203,652	$205,862	$2,210	1.1%	7	81	60.0%	1,455,987	$0.0303	$0.0318
22	1,601,988	1,855,786	$42,018	$44,122	$2,104	5.0%	$223,240	$225,344	$2,104	0.9%	6	87	64.4%	1,644,581	$0.0255	$0.0268
23	1,855,786	2,067,586	$52,178	$54,789	$2,610	5.0%	$260,471	$263,081	$2,610	1.0%	7	94	69.6%	1,908,611	$0.0273	$0.0287
24	2,067,586	2,480,391	$54,917	$57,664	$2,748	5.0%	$298,447	$301,195	$2,748	0.9%	7	101	74.8%	2,207,903	$0.0249	$0.0261
25	2,480,391	2,792,386	$72,606	$76,240	$3,634	5.0%	$362,011	$365,645	$3,634	1.0%	7	108	80.0%	2,649,323	$0.0274	$0.0288
26	2,792,386	3,656,788	$69,281	$72,747	$3,467	5.0%	$416,154	$419,621	$3,467	0.8%	6	114	84.4%	3,084,763	$0.0225	$0.0236
27	3,656,788	5,231,786	$102,879	$108,023	$5,144	5.0%	$585,863	$591,007	$5,144	0.9%	7	121	89.6%	4,270,802	$0.0241	$0.0253
28	5,231,786	8,164,189	$122,252	$128,365	$6,113	5.0%	$795,398	$801,510	$6,113	0.8%	7	128	94.8%	5,846,987	$0.0209	$0.0220
29	8,164,189	58,034,730	$451,106	$473,667	$22,561	5.0%	$2,774,417	$2,796,978	$22,561	0.8%	7	135	100.0%	14,501,914	$0.0311	$0.0327

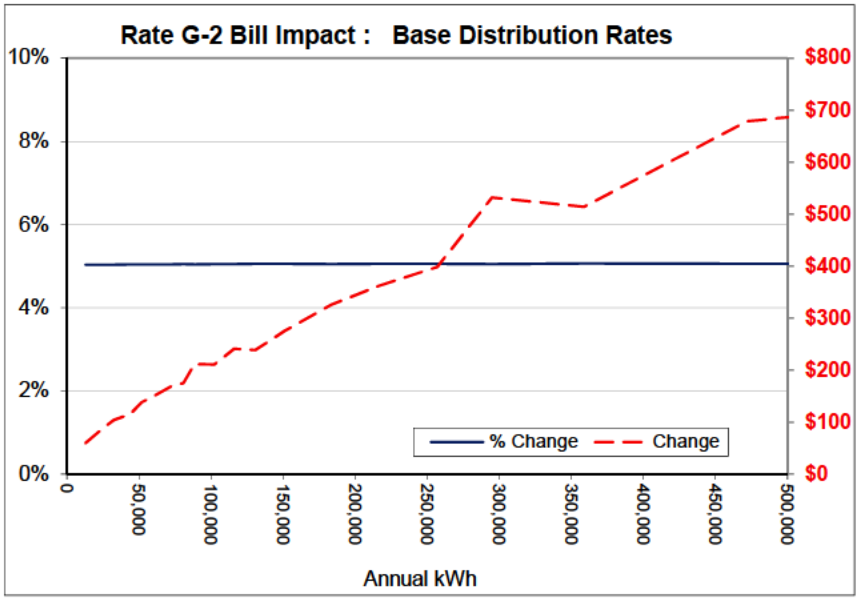
COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE G-2: GENERAL LONG HOUR SERVICE

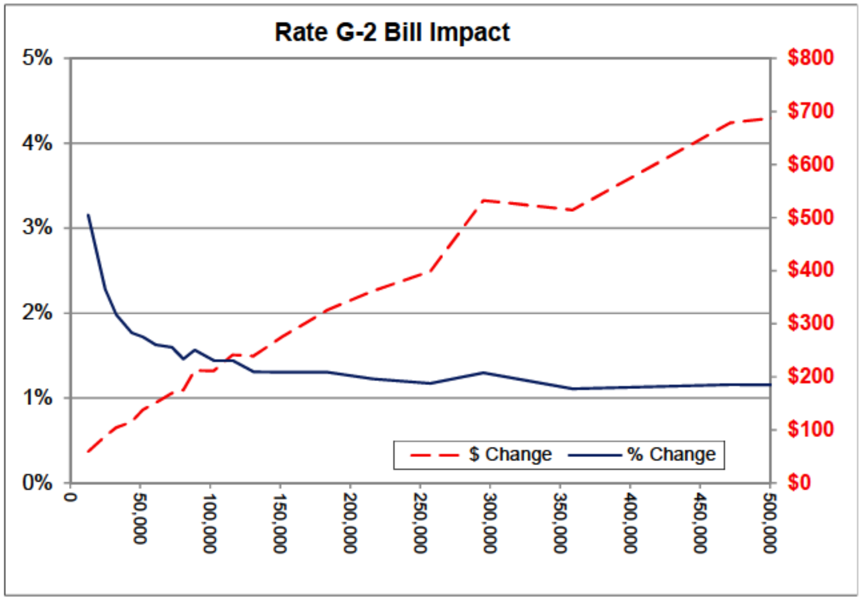
G-2 Proposed Permanent Rates	
Energy Services	$0.07542
Other Tracking Mechanisms	$0.03523
Customer charge	$64.11
Demand Charge	$9.19
kWh Charge	$0.00283

G-2 Proposed Step Adj. Rates	
Energy Services	$0.07542
Other Tracking Mechanisms	$0.03523
Customer charge	$67.35
Demand Charge	$9.65
kWh Charge	$0.00299

G-2 Proposed Permanent Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03523
Customer charge	$64.11
Demand Charge	$9.19
kWh Charge	$0.00283

G-2 Proposed Step Adj. Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03523
Customer charge	$67.35
Demand Charge	$9.65
kWh Charge	$0.00299





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE G-2: GENERAL LONG HOUR SERVICE

Line				
1	**G-2 Proposed Permanent Rates**		**G-2 Proposed Step Adj. Rates**	
2	Energy Services	$0.07542	Energy Services	$0.07542
3	Other Tracking Mechanisms	$0.03523	Other Tracking Mechanisms	$0.03523
4				
5	Customer charge	$64.11	Customer charge	$67.35
6				
7	Demand charge	$9.19	Demand charge	$9.65
8	kWh Charge	$0.00283	kWh Charge	$0.00299
9				

	Annual Use Range		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Proposed Rates
10	0	12,846	$1,184	$1,243	$60	5.0%	$1,887	$1,947	$60	3.2%	39	39	4.5%	5,599	$0.2114	$0.2221
11	12,846	24,865	$1,746	$1,834	$88	5.0%	$3,841	$3,929	$88	2.3%	43	82	9.5%	18,654	$0.0936	$0.0983
12	24,865	32,964	$2,075	$2,180	$105	5.0%	$5,295	$5,399	$105	2.0%	44	126	14.6%	28,908	$0.0718	$0.0754
13	32,964	43,786	$2,284	$2,400	$115	5.0%	$6,513	$6,629	$115	1.8%	43	169	19.6%	37,969	$0.0602	$0.0632
14	43,786	51,821	$2,736	$2,874	$138	5.0%	$8,020	$8,158	$138	1.7%	43	212	24.6%	47,573	$0.0575	$0.0604
15	51,821	60,673	$2,991	$3,142	$151	5.0%	$9,259	$9,410	$151	1.6%	44	256	29.7%	56,448	$0.0530	$0.0557
16	60,673	72,534	$3,355	$3,525	$169	5.0%	$10,573	$10,743	$169	1.6%	43	299	34.6%	64,956	$0.0517	$0.0543
17	72,534	80,887	$3,473	$3,649	$175	5.1%	$12,003	$12,178	$175	1.5%	43	342	39.6%	76,892	$0.0452	$0.0475
18	80,887	88,708	$4,196	$4,408	$212	5.0%	$13,529	$13,741	$212	1.6%	44	386	44.7%	84,167	$0.0499	$0.0524
19	88,708	102,493	$4,182	$4,393	$211	5.1%	$14,654	$14,865	$211	1.4%	43	429	49.7%	94,319	$0.0443	$0.0466
20	102,493	116,102	$4,781	$5,022	$241	5.1%	$16,739	$16,980	$241	1.4%	43	472	54.7%	107,752	$0.0444	$0.0466
21	116,102	130,794	$4,724	$4,963	$239	5.1%	$18,223	$18,462	$239	1.3%	44	516	59.8%	121,668	$0.0388	$0.0408
22	130,794	151,193	$5,448	$5,724	$275	5.1%	$21,078	$21,354	$275	1.3%	43	559	64.8%	140,781	$0.0387	$0.0407
23	151,193	183,655	$6,447	$6,773	$326	5.1%	$24,953	$25,279	$326	1.3%	43	602	69.8%	166,489	$0.0387	$0.0407
24	183,655	216,195	$7,146	$7,508	$362	5.1%	$29,466	$29,828	$362	1.2%	44	646	74.9%	200,973	$0.0356	$0.0374
25	216,195	257,193	$7,876	$8,274	$399	5.1%	$33,916	$34,315	$399	1.2%	43	689	79.8%	234,386	$0.0336	$0.0353
26	257,193	295,033	$10,528	$11,061	$532	5.1%	$40,952	$41,484	$532	1.3%	43	732	84.8%	274,075	$0.0384	$0.0404
27	295,033	358,876	$10,146	$10,660	$514	5.1%	$46,236	$46,750	$514	1.1%	44	776	89.9%	324,711	$0.0312	$0.0328
28	358,876	471,796	$13,406	$14,085	$679	5.1%	$58,549	$59,227	$679	1.2%	43	819	94.9%	405,352	$0.0331	$0.0347
29	471,796	2,019,793	$21,933	$23,046	$1,112	5.1%	$110,006	$111,118	$1,112	1.0%	44	863	100.0%	760,776	$0.0288	$0.0303

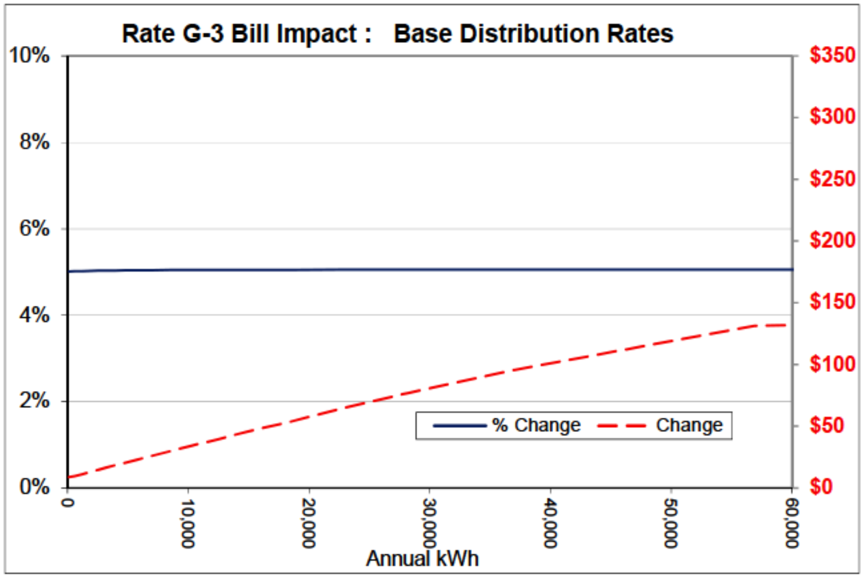
COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE G-3: GENERAL SERVICE

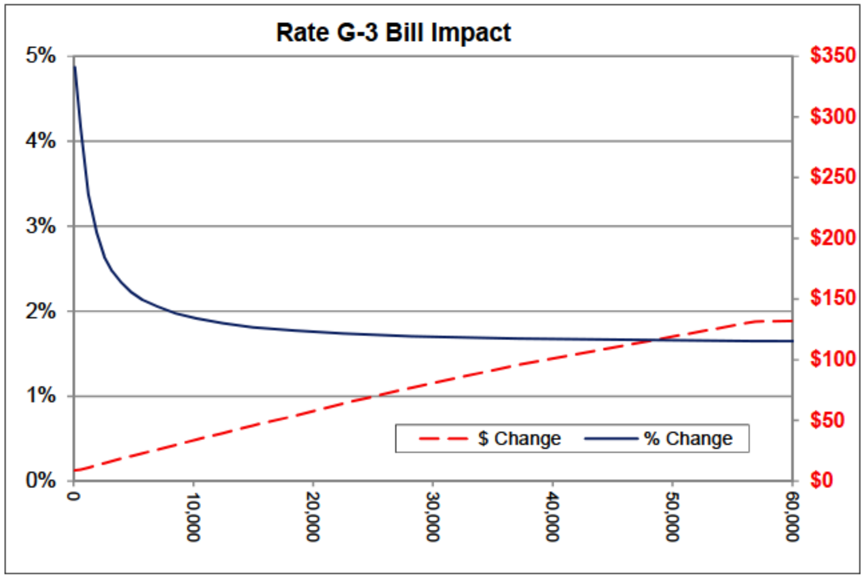
G-3 Proposed Permanent Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03541
Customer charge	$14.76
kWh Charge	$0.05333

G-3 Proposed Step Adj. Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03541
Customer charge	$15.50
kWh Charge	$0.05603

G-3 Proposed Permanent Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03541
Customer charge	$14.76
kWh Charge	$0.05333

G-3 Proposed Step Adj. Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03541
Customer charge	$15.50
kWh Charge	$0.05603





Docket No. DE 19-064
Exhibit 26
Attachment SIS-4

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Attachment DAH-8
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COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE G-3: GENERAL SERVICE

Line	G-3 Proposed Permanent Rates		G-3 Proposed Step Adj. Rates	
1	**G-3 Proposed Permanent Rates**		**G-3 Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03541	Other Tracking Mechanisms	$0.03541
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7				
8	kWh Charge	$0.05333	kWh Charge	$0.05603
9				

	Annual Use Range		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Proposed Rates
10	0	120	$176	$185	$9	5.0%	$182	$190	$9	4.9%	182	182	3.3%	29	$6.1832	$6.4932
11	120	581	$193	$202	$10	5.0%	$232	$242	$10	4.2%	277	459	8.4%	333	$0.5788	$0.6079
12	581	1,235	$224	$235	$11	5.0%	$333	$344	$11	3.4%	278	737	13.5%	920	$0.2433	$0.2555
13	1,235	1,922	$261	$274	$13	5.0%	$448	$461	$13	2.9%	277	1014	18.6%	1,580	$0.1651	$0.1734
14	1,922	2,570	$296	$311	$15	5.0%	$564	$579	$15	2.6%	277	1291	23.7%	2,263	$0.1308	$0.1374
15	2,570	3,218	$329	$346	$17	5.0%	$672	$688	$17	2.5%	278	1569	28.8%	2,888	$0.1140	$0.1198
16	3,218	3,960	$366	$385	$18	5.0%	$788	$807	$18	2.3%	277	1846	33.9%	3,564	$0.1027	$0.1079
17	3,960	4,813	$409	$429	$21	5.0%	$926	$947	$21	2.2%	277	2123	38.9%	4,367	$0.0936	$0.0983
18	4,813	5,738	$455	$478	$23	5.0%	$1,075	$1,098	$23	2.1%	278	2401	44.0%	5,230	$0.0870	$0.0914
19	5,738	6,985	$514	$539	$26	5.0%	$1,261	$1,287	$26	2.1%	277	2678	49.1%	6,306	$0.0814	$0.0855
20	6,985	8,531	$592	$622	$30	5.0%	$1,514	$1,544	$30	2.0%	277	2955	54.2%	7,782	$0.0760	$0.0799
21	8,531	10,250	$678	$713	$34	5.0%	$1,789	$1,823	$34	1.9%	278	3233	59.3%	9,374	$0.0724	$0.0760
22	10,250	12,465	$781	$821	$39	5.1%	$2,121	$2,161	$39	1.9%	277	3510	64.4%	11,311	$0.0691	$0.0726
23	12,465	14,987	$907	$953	$46	5.1%	$2,530	$2,576	$46	1.8%	277	3787	69.5%	13,695	$0.0663	$0.0696
24	14,987	18,468	$1,065	$1,119	$54	5.1%	$3,039	$3,092	$54	1.8%	278	4065	74.6%	16,655	$0.0640	$0.0672
25	18,468	22,444	$1,265	$1,329	$64	5.1%	$3,679	$3,743	$64	1.7%	277	4342	79.6%	20,374	$0.0621	$0.0652
26	22,444	28,211	$1,521	$1,598	$77	5.1%	$4,507	$4,584	$77	1.7%	277	4619	84.7%	25,194	$0.0604	$0.0634
27	28,211	37,030	$1,893	$1,989	$96	5.1%	$5,701	$5,797	$96	1.7%	278	4897	89.8%	32,135	$0.0589	$0.0619
28	37,030	56,880	$2,600	$2,732	$132	5.1%	$7,980	$8,112	$132	1.6%	277	5174	94.9%	45,366	$0.0573	$0.0602
29	56,880	1,043,800	$5,663	$5,950	$287	5.1%	$17,843	$18,130	$287	1.6%	278	5452	100.0%	99,321	$0.0570	$0.0599

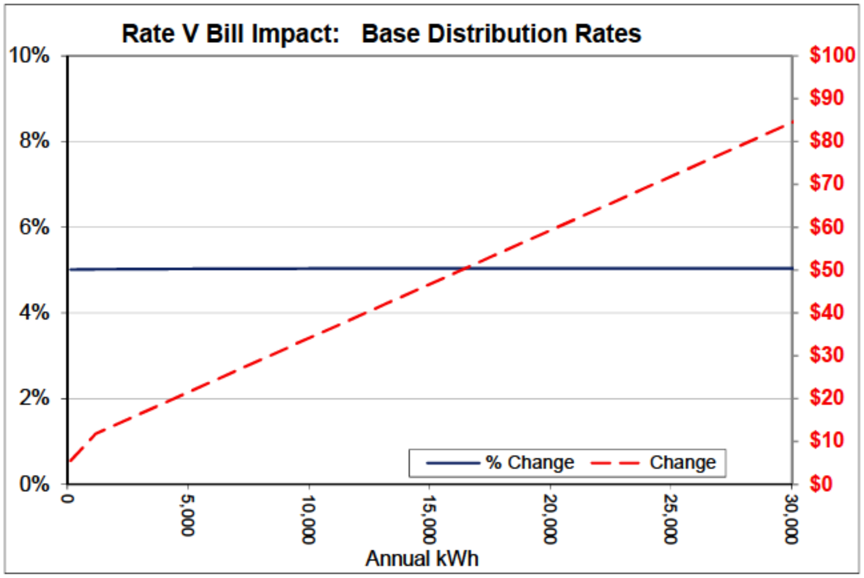
COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE V: LIMITED COMMERCIAL SPACE HEATING

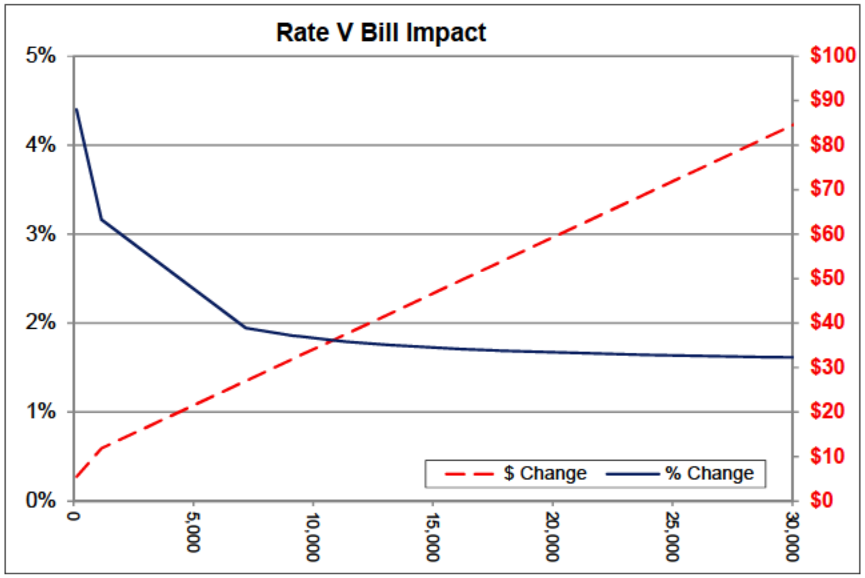
V Proposed Permanent Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03549
Customer charge	$14.76	
kWh Charge	$0.04988	

V Proposed Step Adj. Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03549
Customer charge	$15.50	
kWh Charge	$0.05240	

V Proposed Permanent Rates		
Energy Services		$0.00000
Other Tracking Mechanisms		$0.03549
Customer charge	$14.76	
kWh Charge	$0.04988	

V Proposed Step Adj. Rates		
Energy Services		$0.00000
Other Tracking Mechanisms		$0.03549
Customer charge	$15.50	
kWh Charge	$0.05240	





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE V: LIMITED COMMERCIAL SPACE HEATING

Line				
1	**V Proposed Permanent Rates**		**V Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03549	Other Tracking Mechanisms	$0.03549
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7				
8	kWh Charge	$0.04988	kWh Charge	$0.05240
9				

	Annual Use Range		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Proposed Rates
10	0	128	$109	$115	$5	5.0%	$124	$130	$5	4.4%	1	1	6.3%	128	$0.8532	$0.8960
11	128	1,165	$235	$247	$12	5.0%	$373	$385	$12	3.2%	1	2	12.5%	1,165	$0.2019	$0.2121
12	1,165	7,187	$536	$563	$27	5.0%	$1,387	$1,414	$27	1.9%	1	3	18.8%	7,187	$0.0745	$0.0783
13	7,187	9,151	$634	$666	$32	5.0%	$1,718	$1,750	$32	1.9%	1	4	25.0%	9,151	$0.0692	$0.0727
14	9,151	9,440	$650	$683	$33	5.0%	$1,768	$1,801	$33	1.9%	1	5	31.3%	9,440	$0.0689	$0.0723
15	9,440	10,911	$721	$758	$36	5.0%	$2,014	$2,050	$36	1.8%	1	6	37.5%	10,911	$0.0661	$0.0694
16	10,911	11,408	$746	$784	$38	5.0%	$2,098	$2,135	$38	1.8%	1	7	43.8%	11,408	$0.0654	$0.0687
17	11,408	13,167	$834	$876	$42	5.0%	$2,394	$2,436	$42	1.8%	1	8	50.0%	13,167	$0.0633	$0.0665
18	13,167	16,199	$985	$1,035	$50	5.0%	$2,904	$2,954	$50	1.7%	1	9	56.3%	16,199	$0.0608	$0.0639
19	16,199	17,584	$1,054	$1,107	$53	5.0%	$3,138	$3,191	$53	1.7%	1	10	62.5%	17,584	$0.0600	$0.0630
20	17,584	17,799	$1,065	$1,119	$54	5.0%	$3,174	$3,227	$54	1.7%	1	11	68.8%	17,799	$0.0598	$0.0629
21	17,799	23,843	$1,366	$1,435	$69	5.0%	$4,191	$4,260	$69	1.6%	1	12	75.0%	23,843	$0.0573	$0.0602
22	23,843	28,803	$1,614	$1,695	$81	5.0%	$5,026	$5,108	$81	1.6%	1	13	81.3%	28,803	$0.0560	$0.0589
23	28,803	49,606	$2,651	$2,785	$134	5.0%	$8,529	$8,663	$134	1.6%	1	14	87.5%	49,606	$0.0535	$0.0561
24	49,606	50,878	$2,715	$2,852	$137	5.0%	$8,743	$8,880	$137	1.6%	1	15	93.8%	50,878	$0.0534	$0.0561
25	50,878	61,120	$3,226	$3,389	$163	5.1%	$10,467	$10,630	$163	1.6%	1	16	100.0%	61,120	$0.0528	$0.0554

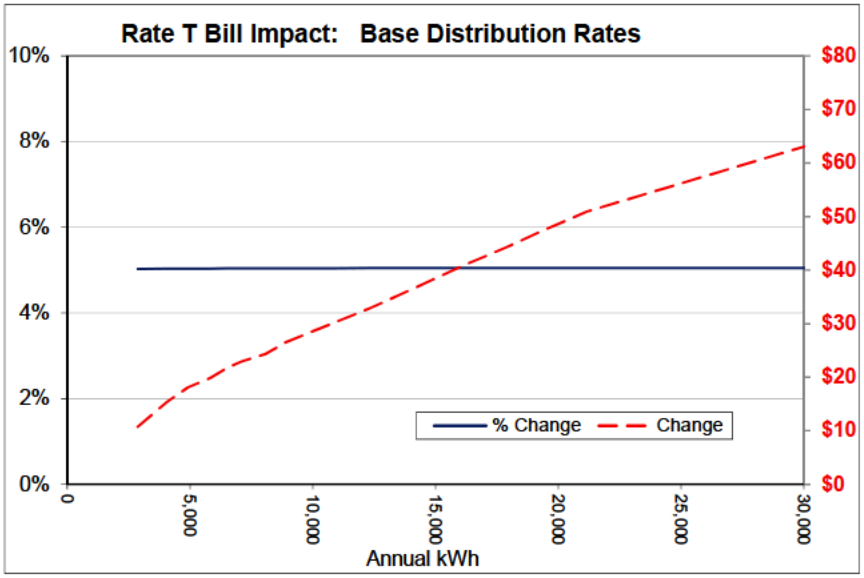
COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE T: LIMITED TOTAL ELECTRICAL LIVING

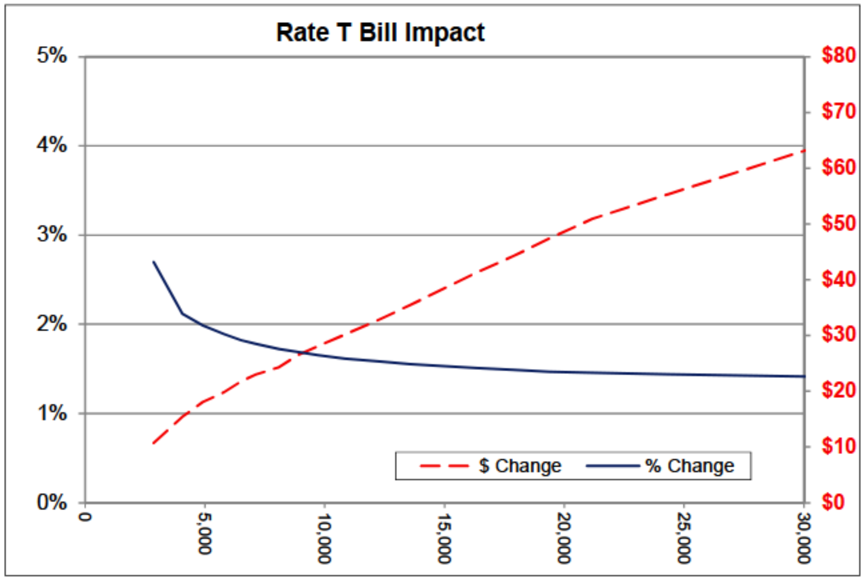
T Proposed Permanent Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03934
Customer charge	$14.76
kWh Charge	$0.04088

T Proposed Step Adj. Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.03934
Customer charge	$15.50
kWh Charge	$0.04295

T Proposed Permanent Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03934
Customer charge	$14.76
kWh Charge	$0.04088

T Proposed Step Adj. Rates	
Energy Services	$0.00000
Other Tracking Mechanisms	$0.03934
Customer charge	$15.50
kWh Charge	$0.04295





COMPARATIVE ANNUAL BILLS UNDER PROPOSED PERMANENT AND PROPOSED STEP ADJUSTMENT RATES
RATE T: LIMITED TOTAL ELECTRICAL LIVING

Line				
1	**T Proposed Permanent Rates**		**T Proposed Step Adj. Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03934	Other Tracking Mechanisms	$0.03934
4				
5	Customer charge	$14.76	Customer charge	$15.50
6				
7				
8	kWh Charge	$0.04088	kWh Charge	$0.04295
9				

	Annual Use Range		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Proposed Rates	Change	% Change	Current Rates	Proposed Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Proposed Rates
10	0	2,864	$214	$224	$11	5.0%	$398	$409	$11	2.7%	40	40	4.9%	1,368	$0.1561	$0.1639
11	2,864	4,075	$307	$322	$15	5.0%	$731	$746	$15	2.1%	41	81	9.9%	3,436	$0.0893	$0.0938
12	4,075	4,915	$359	$377	$18	5.0%	$910	$928	$18	2.0%	41	122	15.0%	4,487	$0.0799	$0.0839
13	4,915	5,809	$393	$413	$20	5.0%	$1,050	$1,070	$20	1.9%	41	163	20.0%	5,347	$0.0736	$0.0773
14	5,809	6,514	$432	$454	$22	5.0%	$1,195	$1,217	$22	1.8%	41	204	25.0%	6,222	$0.0695	$0.0730
15	6,514	7,131	$456	$479	$23	5.0%	$1,291	$1,314	$23	1.8%	40	244	29.9%	6,800	$0.0671	$0.0705
16	7,131	8,084	$482	$507	$24	5.0%	$1,411	$1,435	$24	1.7%	41	285	34.9%	7,557	$0.0638	$0.0670
17	8,084	8,863	$524	$550	$26	5.0%	$1,562	$1,588	$26	1.7%	41	326	40.0%	8,467	$0.0618	$0.0650
18	8,863	9,703	$555	$583	$28	5.0%	$1,692	$1,720	$28	1.7%	41	367	45.0%	9,269	$0.0599	$0.0629
19	9,703	10,845	$598	$628	$30	5.0%	$1,864	$1,894	$30	1.6%	41	408	50.0%	10,325	$0.0579	$0.0608
20	10,845	12,325	$652	$685	$33	5.1%	$2,079	$2,112	$33	1.6%	40	448	54.9%	11,611	$0.0562	$0.0590
21	12,325	13,542	$701	$736	$35	5.1%	$2,275	$2,311	$35	1.6%	41	489	59.9%	12,829	$0.0546	$0.0574
22	13,542	14,873	$756	$795	$38	5.1%	$2,490	$2,528	$38	1.5%	41	530	65.0%	14,139	$0.0535	$0.0562
23	14,873	16,262	$814	$855	$41	5.1%	$2,722	$2,763	$41	1.5%	41	571	70.0%	15,559	$0.0523	$0.0550
24	16,262	17,876	$875	$919	$44	5.1%	$2,965	$3,009	$44	1.5%	41	612	75.0%	17,044	$0.0514	$0.0539
25	17,876	19,379	$938	$985	$47	5.1%	$3,222	$3,270	$47	1.5%	40	652	79.9%	18,634	$0.0503	$0.0529
26	19,379	21,158	$1,007	$1,058	$51	5.1%	$3,492	$3,543	$51	1.5%	41	693	84.9%	20,267	$0.0497	$0.0522
27	21,158	24,370	$1,096	$1,151	$55	5.1%	$3,844	$3,899	$55	1.4%	41	734	90.0%	22,390	$0.0489	$0.0514
28	24,370	30,990	$1,275	$1,339	$64	5.1%	$4,559	$4,623	$64	1.4%	41	775	95.0%	26,685	$0.0478	$0.0502
29	30,990	669,280	$3,639	$3,823	$184	5.1%	$14,000	$14,184	$184	1.3%	41	816	100.0%	69,131	$0.0526	$0.0553