STATE OF NEW HAMPSHIRE
BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 24-070
REQUEST FOR CHANGE IN RATES

DIRECT TESTIMONY OF

Bradley Cebulko

Cost of Service, Revenue Allocation, Residential Rate Design, K-Bar

January 24, 2025

Introduction

Q. Please state your name and business address.

A. My name is Bradley Cebulko. My business address is 2900 E Broadway Blvd, Ste 100 #780, Tucson, AZ, 85716.

Q. Please describe your professional experience, educational background, and qualifications.

A. I am a Partner at Current Energy Group ("CEG"), which I co-founded in May 2024. CEG provides consumer advocates, public interest organizations, and public utility commissions technical, economic, and policy advisory services on electric and gas regulatory issues. At CEG, I work on a wide array of issues including gas and electric cost-of-service modeling, new regulatory business models, integrated resource planning, amongst other issues. Prior to founding CEG, I briefly worked for my own sole proprietorship and, prior to that, was a Senior Manager at Strategen Consulting from 2021 to 2024. Before Strategen, I worked at the Washington Utilities and Transportation Commission ("UTC") for eight years. From 2013-2016, I was an analyst with the UTC Commission Staff focused on electric and natural gas integrated resource planning ("IRP"), electric and natural gas energy efficiency programs, and new program design and implementation. From 2016-2021, I was an advisor to the UTC Commissioners where I led commissioner review of general rate cases and rulemakings.

I have a master's in public administration from the University of Washington Evans School of Public Policy and Governance, and a Bachelor of Arts in Political Science from Colorado State University. My curriculum vitae is attached as Appendix A.

Q. Have you previous testimony in regulatory proceeds on utility rates?

A. Yes, I have testified on a range of electric and gas issues before public utility commissions in Massachusetts, Maryland, Connecticut, Michigan, Illinois, Minnesota, Colorado, North Dakota, Oregon, and Washington.

Q. On whose behalf are you appearing?

A. I am presenting testimony on behalf of AARP.

Q. Have you previously testified in New Hampshire?

A. No.

Q. Have you testified in any other jurisdictions?

A. Yes. I have testified in Massachusetts, Connecticut, Maryland, Ohio, Michigan, Illinois, Minnesota, Colorado, North Dakota, Arizona, Oregon, Washington, and Ontario.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and analyze the Company's Allocated Cost of Service Study ("ACOSS"), revenue apportionment, residential customer rate design, and K-Bar proposal, and make recommendations to the Commission.

Q. Will you please summarize recommendations?

A. Yes. I recommended the following:

1. Use the results of a Basic Customer methodology for the Allocated Cost of Service Study (ACOSS),
2. Use the results of the basic customer ACOSS to inform revenue apportionment consistent with my proposal in testimony,
3. Maintain the residential customer charges at their present rates, and
4. Reject the Company's K-Bar proposal.

Allocated Cost of Service Study

Q. Did the Company file an allocated cost of service study?

A. Yes. The Company filed an Allocated Cost of Service ("ACOS") Study, which is an update to the ACOS study the utility filed in its 2019 general rate case (GRC).[1] The Company uses the ACOS study to inform its proposed revenue apportionment.

Q. What the purpose of an ACOS study?

A. The purpose of an ACOS study is to determine, with as much granularity as is reasonable, which customer class caused the utility's embedded costs. That is, it is a study for assigning costs of the existing system to each customer class. The ACOSS is then used to inform apportioning revenue increases/decreases and designing rate structures.

Q. How is an ACOS study performed?

A. An ACOS study has three steps. First, costs are functionalized into categories such as generation, transmission, distribution, and billing/customer. Second, costs are classified as energy-, demand-, or customer-related. Lastly, the costs are allocated to the various customer classes using allocation factors.

Q. Let's walk through each step. How are costs functionalized?

A. Public utilities are required to maintain records in accordance with the Uniform System of Accounts as designated by the Federal Energy Regulatory Commission ("FERC"). These accounts assign costs based on the high-level functions of the system: generation,

[1] Nieto Direct p. 2, lines 13 – 15.

transmission, distribution, and general/customer. Through functionalization costs are assigned either to a specific customer class or are identified as the joint responsibility of multiple customer classes. An electric utility may also subfunctionalize certain types of costs, such as segregating distribution lines into primary and secondary components.

Q. How are costs then classified?

A. Each function's costs are then classified by their cause, demand-, energy-, or customer-related. Energy costs are classified based on a customer class's energy usage, measured in kilowatt-hours ("kWh"). Demand costs are classified based on a customer class's contribution to peak demand, measured in kilowatts ("kW") within the system. Customer costs are those required to provide service to customers regardless of whether the customers consume electricity. The National Association of Regulatory Utility Consumers ("NARUC") Electric Utility Cost Allocation Manual defines customer cost as "costs that are directly related to the number of customers served."[2]

Q. Finally, how are costs allocated?

A. Costs are allocated to customer classes based on each class's contribution to that specific cost using an allocation factor. For example, demand-related costs may be allocated based on a customer class's contribution to the system's annual coincidental peak (e.g., 12 CP, 4 CP, etc.) or the customer class's noncoincidental peak during the year.

[2] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual,* January 20, 1992. P. 20.

Q. How should an ACOS analysis be used in a rate case?

A. A cost of service study, whether it is an allocated or marginal cost of service study, is a tool and the appropriate starting point for informing rates. But a cost of service study is an imprecise tool. A cost of service study necessarily requires numerous subjective determinations that will have significant impacts on the outcomes. For example, reasonable people may disagree whether it is better to allocate demand costs based on noncoincidental peak or 12 coincidental peaks. As another example, in his 1961 book on the Principles of Public Utility Rates, James C. Bonbright discussed the controversial aspect of assigning annual maintenance and capital costs of secondary distribution system costs as "customer costs."[3] Given that subjective decisions can have significant impacts on the outcome of the cost of service study, it is appropriate for public utility commissions to review several commonly accepted methodological approaches and consider the range of results when determining revenue allocation and rate design.

Q. Are all ACOS methodologies equally valid?

A. No. Although no ACOS method is perfect, some ACOS methodologies are better supported by economic theory and regulatory principles than others, and the Commission should give more weight to those methods.

Q. What ACOS methodology did Eversource use in this case?

A. In this case, the Company classifies distribution station plant (Account 362) in its entirety as demand-related. For poles, transformers, underground and overhead circuits (Accounts

[3] James C. Bonbright, *Principles of Public Utility Rates* 348 (1st ed. 1961)

364, 365, 366, 367 and 368), the Company uses a Minimum System method for classifying costs as either demand or customer-related. The Minimum system method assumes that a minimum distribution system can be built to serve the minimum load requirements of the customer.[4] As such, the Company identifies the average cost for each primary plant in each account and is multiplied by the total existing inventory. The total costs of the minimum sized plant is divided by the total cost of the actual plant in service to determine the "customer-related" costs. The remaining costs are considered to be "demand-related."

Figure 1: Eversource Minimum System Study Classification Factors[5]

Account Number		Demand	Customer
364	POLES - PRIMARY	20.3%	79.7%
364	POLES - SECONDARY	18.0%	82.0%
365	PRIMARY OH LINES	69.0%	31.0%
365	SECONDARY OH LINES (1ph)	63.4%	36.6%
366, 367	PRIMARY UG LINES 1-PH	84.7%	15.3%
366, 367	PRIMARY UG LINES 3-PH	93.7%	6.3%
366, 367	SECONDARY UG LINES -1ph	69.0%	31.0%
368	OH TRANSFORMERS	58.5%	41.5%
368	UG TRANSFORMERS	88.3%	11.7%

Q. Do you have any concerns with the Company's use of the Minimum System method for classifying costs as either demand- or customer-related?

A. Yes. While I recognize that the Minimum System method is a commonly used methodology, there are better methods classifying the embedded costs of the system. The

[4] NARUC electric manual p. 90.
[5] Nieto p. 19198.

Minimum System method is grounded on an unrealistic concept of a hypothetical utility that has no basis in reality. The impact of using this method is that a higher proportion of costs are shifted onto customer classes with larger numbers of customers, primarily the residential customer class.

Q. Please explain why the Minimum System method is based on an unrealistic concept of a hypothetical utility.

A. The Minimum System method requires the creation of a hypothetical system that would have been built if there was no demand and assigns the costs as "customer related." Said another way, the Minimum System method assumes that there is some portion of the system whose costs are unrelated to actual customer demand.[6] As shown in Figure 1 above, approximately 80% of costs in Account 364 (Poles, towers and fixtures) are allocated as "customer-related."

Close scrutiny of the method unveils its logical fallacy. To start, if there was no demand from customers than the system wouldn't be built. So, the idea of a hypothetical minimum utility without any demand is without merit. It is customer demand that drives the need for any investment.

A cost should only be considered a customer-cost if the removal of a single customer removes the need for that equipment. With rare exception, the Company does not remove a utility pole or transformer from the distribution line if a customer

[6] Weston, F. "Charging for Distribution Utility Services: Issues in Rate Design" Regulatory Assistance Project, 2000. P. 30.

disconnects from the system. As I previously mentioned, the National Association of Regulatory Utility Consumers ("NARUC") Electric Manual defines customer cost as "costs that are directly related to the number of customers served."[7] The utility does not add a new pole or a new transformer each time a customer connects to the system. Rather, the components of the distribution system are sized to meet a certain level of demand for now and into the future.

In a 2020 paper on electric cost allocation, the Regulatory Assistance Project (RAP) wrote that it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related for eight reasons.[8] While I will not repeat each of the reasons in this testimony, it is worth expanding upon three of the arguments identified in the paper:

1. There is a weak correlation between the area, or milage, of a distribution system and the number of customers it serves.
2. Load can help determine the type of equipment that is installed.
3. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors.

Q. Why is there a weak correlation between the mileage of the distribution system and the number of customers it serves?

A. The size of the electric distribution system does not account for the density of customers on the system. The electric utility must build its system to connect the entirety of its

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8 Lazar, J. et al. "Electric Cost Allocation for a New Era, A Manual" Regulatory Assistance Project, 2020. P. 145.

geographic area. The costs of that system is the same regardless of the number of customers connected, and changes to those costs are (for the most part) driven by changes in demand. That the Minimum System method does not account for the density factor led James Bonbright to dismiss the inclusion of the costs of a minimum-sized distribution system as customer-related costs as "clearly indefensible."[9]

Q. Please explain the relevance of adding customers with and without contributions to peak demand for assigning distribution costs.

A. Unless there is a change in peak demand, adding a customer onto the distribution system, should not trigger additional costs to the distribution system. For example, imagine a one-mile distribution line running from Point A to Point B with 10 customers. If two additional customers connect to the system along the 1-mile line, but there is no increase in demand to the system, the utility would not need to make investments such as additional poles or conductors. Likewise, if two customers departed the system the utility would not remove poles or conductors from the one-mile segment. A utility may have to make upgrades to the system, however, if the additional customers' contribution to the peak demand on the segment trigger the need for additional investments.

Q. Is there another method that you recommend for classifying distribution system costs?

A. Yes. I recommend that the Commission adopt the Basic Customer method, which only classifies only customer-specific costs as customer-related, and the rest of the distribution

[9] Bonbright 1961 p. 348.

system as energy- or demand-related. The Basic Customer method recognizes that the system is built for meeting customer demand and does not vary significantly based on the number of customers. Classifying distribution costs as energy- or demand-related, as opposed to customer-related, better conforms to cost causation and fairness than the Minimum System method for the reasons I just discussed. Namely, customer-related costs are "costs that are directly related to the number of customers served"[10] and the costs of the distribution system, for the most part, do not change with the addition or subtraction of customers.

Q. What would the impact of using the Basic Customer method rather than the Minimum System method?

A. The Basic Customer method classifying FERC accounts 364 – 368 as 100 percent demand-related.

[10] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual,* January 20, 1992. P. 20.

Q. Are there other public utility commissions that use the Basic Customer method or a similarly situated demand-related method?

A. Yes, I know of several commissions including Connecticut,[11] Illinois,[12] Iowa,[13] California,[14] Rhode Island,[15] Maryland,[16] Washington state,[17] and Arkansas.[18]

Specifically, the Arkansas Public Service Commission wrote "[t]he Commission agrees with EAI, Staff and AG that accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and find that AEEC and HHEG do not provide sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes."[19] Indeed, Washington state went so far as to specify in rule the electric cost of service approved classification and

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[11] *See* https://law.justia.com/codes/connecticut/2015/title-16/chapter-283/section-16-243bb/

[12] Final Order, *Commonwealth Edison Company Proposed General Increase in Electric Rates (Tariffs filed October 17, 2007)*, at 208 (Sep. 10, 2008), Docket No. 07-0566 (Illinois Commerce Commission)

[13] Iowa Admin. Code 199-20.10(2)(e).

[14] Interim Opinion, *Re San Diego Gas and Electric Company*, (Dec. 19, 1988), Decision 88-12-085 (California Public Utilities Commission), (1988 WL 1663871), at 15.

[15] Decision and Order, *In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution* Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).

[16] Order No. 83907, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base* Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland).

[17] Ninth Supplemental Order on Rate Design Issues, *Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Benefits*, (Aug. 16, 1993) Docket No. UE-920433 (Washington Utilities and Transportation Commission) (1993 WL 13812140), at 5–6.

[18] Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).

[19] Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission)

allocation methodologies, and specifically requires distribution substations, distribution line transformers, and distribution poles and wires as demand related.[20]

Q. How did the Company allocate demand-related costs for Accounts 365 – 368?

A. The Company study uses class non-coincidental peak (NCP).

Q. Do you have any concerns with the Company's use of NCP to allocate demand-related costs for Accounts 365 – 368?

A. No. I find that using the NCP method for allocating demand-related costs for electric distribution system investments is a generally reasonable methodology.

Figure 2: Eversource ACOS Distribution Rate Required Change

Rate Class	Current Distribution Revenue	Existing Earned Return	ACOS Revenue Target at 7.44%	ACOS Revenue Difference	ACOS Required Percent Change
	(000$)	%	(000$)	(000$)	%
R PL+TOD	$244,615	-1.32%	$390,612	$145,997	59.68%
R LCS	$646	-8.41%	$1,962	$1,316	203.56%
RWH	$4,203	-4.04%	$7,768	$3,564	84.80%
GS + GS TOD	$96,493	4.30%	$111,118	$14,625	15.16%
G SH	$181	2.58%	$227	$46	25.26%
G LCS	$50	-9.60%	$178	$128	256.37%
G-WH	$136	-2.67%	$223	$87	64.07%
GV	$43,045	3.65%	$51,608	$8,563	19.89%
LG	$21,077	1.43%	$28,551	$7,474	35.46%
RATE B	$1,558	1.22%	$2,078	$520	33.39%
OL	$4,277	6.62%	$4,386	$110	2.57%
EOL	$2,062	10.93%	$1,913	($150)	-7.25%
Total	**$418,343**	**0.29%**	**$600,624**	**$182,281**	**43.57%**

Revenue Apportionment

[20] See Washington administrative Code 480-85-060. Available at: https://app.leg.wa.gov/WAC/default.aspx?cite=480-85-060

Q. What is the Company's proposed revenue apportionment to each customer class?

A. The Company stated that it primarily relied on its fully allocated, total class revenue requirements from the ACOSS to allocate revenue requirements to each rate class, with modifications to avoid what the Company calls "unacceptable bill impacts."[21] As shown in Figure 3 below, the Company testifies that it is proposing a 16.8% increase for residential customers.

Figure 3:Public Service Company of New Hampshire's Proposed Revenue Allocation in ($000)

Rate Class	Current Revenue	Proposed Revenue	Change	Percent Change
Residential Rate R & R-OTOD2	$696,306	$813,433	$117,128	16.8%
General Service Rate G & G-TOD	310,226	346,130	35,904	11.6%
Primary General Service Rate GV & EV-2	304,698	321,665	16,967	5.6%
Large General Service Rate LG	202,144	211,743	9,598	4.8%
Outdoor Lighting OL & EOL, EOL-2	9,462	11,763	2,301	24.3%
Total	**$1,522,836**	**$1,704,735**	**$181,899**	**11.9%**

Q. Is the Company calculated revenue allocation increase a fair representation of the Company's proposed revenue increase to customers?

A. Not entirely. The Company is showing the requested incremental revenue as a percentage of total revenue, including revenue associated with costs outside the Company's control, such as transmission, energy, and other nonbypassable surcharges. For the most part, the Company only has control over distribution costs. If we look at the Company's proposed

[21] Davis, p. 5.

distribution revenue increase request as a percentage of current distribution revenue, it is apparent that the Company's revenue increase is extraordinary. As shown in Table 1 below, the Company is requesting a *47% increase* in distribution revenue from residential customers over the term of the MRP.

Table 1:PSCNH Current and Proposed Distribution Revenue[22]

Rate Class	Current Revenue	Proposed Revenue	Change	Percent Change
Residential (Rate R & R-OTOD2)	$249,464,535	$366,593,341	$117,128,806	47%
General Service (Rate G & G-TOD)	$96,860,565	$132,765,058	$35,904,494	37%
Primary General Service (GV and EV-2)	$43,309,598	60,276,705	$16,967,107	39%
Large General Service (LG)	23,370,087	$31,968,395	$9,598,308	43%
Outdoor Lighting (OL & EL, EOL-2)	6,338,708	$8,640,084	$2,301,376	36%
Total Company	**$418,343,493**	**$600,242,374**	**$181,898,881**	**43%**

Q. What is the Company's approach to allocating revenue?

A. The Company testifies that is primarily relied on its allocated cost of service study with modifications to avoid what it determined to be unacceptable bill impacts.[23] The Company's first step was to allocate equal percentage increases to all customer classes equivalent to the system average of 43%.[24] Then, the Company made adjustments to move each customer class closer to the Company's cost of service revenue

[22] Attachment ES-EAD-11
[23] Direct Testimony of Edward A. Davis at 5.
[24] Attachment ES-EAD-11.

recommendation. The impact of the second step was to increase the residential customers' revenue allocation by another 6%, or $8.659 million.[25]

Q. Are the Company's proposed class revenue allocations reasonable?

A. No. As I explained earlier in my testimony, I do not agree with the Company's proposed ACOS study, which uses the minimum system methodology, and allocates more costs to the residential class than is reasonable.

Q. Please describe your approach to revenue allocation to customer classes.

A. I primarily relied on the results of my Basic Customer ACOS results. I then adjusted each customer class to move them closer towards revenue/cost parity based on the Basic Customer ACOS study. However, I moderated the customer class increases and decreases so as not to create rate shock for any customer class, in accordance with the regulatory principle of gradualism.

Q. What is your recommended revenue allocation to each customer class?

A. I recommend the Commission adopt the revenue allocation from Table 2 below. My revenue allocations are based on a Basic Customer ACOS methodology.

Table 2: AARP Proposed Distribution Revenue

Rate Class	Current Distribution Revenue	Proposed Distribution Revenue	Change	Percentage Increase
Residential (Rate R & R-OTOD2)	$249,464,535	$354,353,319	$104,888,784	42%
General Service (Rate G & GTOD)	$96,860,565	$137,336,069	$40,475,503	42%
Primary General Service (GV and EV-2)	$43,309,598	$65,842,025	$22,532,428	52%

[25] Attachment ES-EAD-11.

Large General Service (LG)	$22,370,087	$33,888,977	$11,518,890	51%
Outdoor Lighting (OL & EL, EOL-2)	$6,338,708	$8,821,981	$2,483,273	39%
Total	**$418,343,493**	**$600,242,372**	**$181,898,879**	43%

Q. If the Commission authorizes a revenue increase less than the Company's requested, how do you propose the Commission allocates revenues?

A. I recommend that the Commission scale back my recommended customer class increases in proportion to the Commission's decrease of the Company's request.

<u>Residential Rate Design</u>

Q. What is the purpose of this section?

A. In this section of my testimony, I respond to the Company's proposed residential rate design changes and make alternative recommendations to the Commission.

Q. What changes to residential rate design is the Company proposing in this case?

A. As shown in Table 3, the Company is proposing to increase all residential rate classes basic customer charges by 43%.

Table 3: PSCNH Current and Proposed Residential Customer Charge Increases[26]

Customer Class	Current Customer Charge	Proposed Customer Charge	% Increase
Residential R	$13.81/mo.	$19.81/mo.	43.45%
Uncontrolled/Controlled Water Heating	$4.87/mo.	$6.99/mo.	43.53%
R-OTOD2	$16.50/mo.	$23.67/mo.	43.53%

[26] Attachment ES-EAD-12.

Q. What is the Company's justification for increasing the residential customer charge by 43%?

A. The Company testifies that it relied on its marginal cost of service study for informing its customer charge recommendations.[27] For Residential Rate R, the Company's testifies that its MCOS indicates that the marginal customer cost for Rate R is $18.14/mo. However, the Company is proposing to increase the Rate R customer charge to $19.81/mo. to be equi-proportional.[28]

Q. Is the Company's proposal to increase residential customer charges by 43% reasonable?

A. No, for five reasons.

1. A 43% increase is to the customer charge violates the regulatory principles of gradualism,
2. High customer charges discourage an efficient use of the electric grid,
3. High customer charges reduce a customer's ability to control their own bill, which disproportionately hurts lower income residents,
4. Higher fixed customer charges shift costs from high-usage customers onto low-usage customers, and
5. High customer charges work against state policy for energy efficiency.

[27] Direct Testimony of Edward Davis at 8.
[28] Direct Testimony of Edward Davis at 8.

Q. Let's start with your first point. What is the regulatory principle of gradualism, and why does a 43% increase to the customer charge violate the principle?

A. Gradualism refers to the concept that adjustments to rates, policies, and programs should be incremental rather than abrupt. The concept is to minimize disruptions and allow people and processes impacted by the movement time to adjust. Although the Company states that it took gradualism into account when it proposed its rates, unfortunately the Company failed. In this instant case, the Company is seeking a one-time 43% increase on a residential's customer's monthly fixed charge. A one-time 43% increase, simply, is not gradual.

Q. Please explain why a high customer charge discourages the efficient use of the electric grid.

A. A customer pays the same residential system charge every month regardless of how much energy that customer uses. By shifting more of the costs out of the variable charge and into the fixed customer charge, the customer has less of an incentive to control their energy use through energy efficiency and conservation. There is an elasticity of demand to energy services, even for residential customers, and customers generally respond rationally to price signals. The less it matters how much energy a customer uses the more likely that customer is to use more energy and thereby contribute to triggering additional capital and operational expenditures upon the system.

Q. Please explain why a high customer charges reduce a customer's ability to control their own bill?

A. As I just explained, by shifting more of the costs out of the variable charge and into the fixed customer charge, the customer has less of an incentive, and less of an ability, to control their energy use through energy efficiency and conservation. No matter how little energy a customer uses, it can never reduce the fixed customer charge.

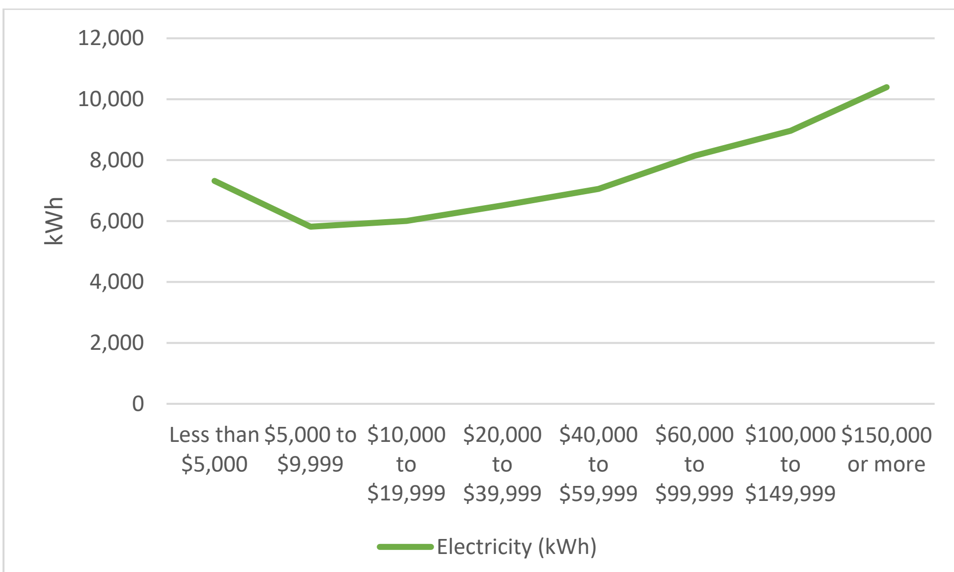
Q. How do high customer charges shift costs from high-usage customers onto low-usage customers?

A. A customer's bill is principally comprised of two components: a fixed, monthly charge and the variable charge. Each customer in a customer class pays the same fixed customer charge regardless of how much the individual customer uses the system. The variable charge, on the other hand, is applied to a customer's usage, so the more the customer uses, the more that customer contributes to the system costs. When costs are shifted from the variable charge to the system charge, more of the costs of the system are collected through the fixed customer charge. The residential system charge comprises a relatively larger portion of the total customer bill for lower usage customers than it does for higher usage customers. Thus, shifting costs from the variable charge into the residential system charge shifts costs from high-usage customers to lower usage customers. Moreover, usage is often correlated with income. All else equal, lower income residents are more likely to be lower usage customers as well. When this is true, high fixed charges shift costs onto lower incomes residential customers.

Q. Do you have any data that supports your claim that low-income customers are more likely to be lower usage customers?

A. Yes. The US Energy Information Administration ("EIA") publishes energy use data through its Residential Energy Consumption Survey ("RECS"), including annual household consumption by household income. According to the RECS data released in March 2024, there is a clear and consistent correlation between income and energy usage across each Northeast census region, which includes New Hampshire, as shown in Figure 4 below.[29] The correlation between energy use and household income in the Northeast is consistent with other regions across the country.

Figure 4: Annual Household Electricity in Northeast Region by Household Income[30]



[29] U.S. Energy Information Administration, *2020 Residential Energy Consumption Survey: Table CE1.2 Households Site End-Use Consumption and Expenditures in the U.S. – Totals and Averages by Climate Region.* March 2024. Available at: https://www.eia.gov/consumption/residential/data/2020/c&e/xls/ce2.2.xlsx

[30] U.S. Energy Information Administration, *2020 Residential Energy Consumption Survey: Table CE1.2 Households Site End-Use Consumption and Expenditures in the U.S. – Totals and Averages by Climate*

Q. Finally, why do you argue that a high customer charge works against state policy to promote energy efficiency?

A. The state has a long track record of achieving energy efficiency savings for its customers. As the electric and gas utilities stated in the 2024-2026 New Hampshire Statewide Energy Efficiency Plan, energy efficiency is the lowest-cost energy resource available, yet significant barriers exist to the adoption of high-efficiency equipment and behaviors.[31] For the reasons explained in my testimony, increasing the fixed customer charge will construct another barrier for adopting high-efficiency equipment and behaviors.

Q. What is your recommended residential customer charge?

A. I recommend the Commission maintain the current residential customer charge. Maintaining the current residential customer charge is appropriate because it incentivizes customers to engage in energy efficiency and conservation programs, which reduces demand and creates a more efficient system that benefits all customers.

<u>K-Bar</u>

Q. What is a Capital Revenue Formula (K-bar)?

A. A Capital Revenue Formula, also known as a "K-bar" or "K-bar Mechanism" is a regulatory mechanism that is designed to give the Company additional funding for capital

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Region. March 2024. Available at: https://www.eia.gov/consumption/residential/data/2020/c&e/xls/ce2.2.xlsx

[31] "2024 – 2026 New Hampshire Statewide Energy Efficiency Plan" Jointly submitted by New Hampshire's Electric and Natural Gas Utilities. June 30, 2023. at 5.

investments over the course of the multiyear plan (MRP). A K-bar allows the utility to recover costs associated with capital expenditures during the MRP based on a rolling historical average of actual capital plant. In its testimony, the Company proposes a K-bar that is applied to all capital investments based on a rolling three-year historical average of actual capital additions, adjusted by an I-X formula and an Earnings Sharing Mechanism.[32]

Q. What is the purpose of a K-bar?

A. Within the context of a PBR framework, a K-bar provides supplemental revenue associated with a utility's planned capital investment formulas set at the beginning of an MRP term. In other words, a K-bar provides an avenue for a utility to recover funding for its planned capital expansion during the course of the MRP informed by the Company's historical capital spending. Based on the Company's K-bar proposal, there are four factors that determine the K-bar's annual funding during the MRP:

1. An amount of eligible capital recovery based on a rolling historical three-year average of actual capital additions prior to each MRP year, subject to I-X factor adjustments in a five-step process.[33]
2. An annual cap to the K-bar of 10% above the forecasted annual capital spending included in the Company's five-year capital budget.[34]

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[32] Direct Testimony of Douglas W. Foley, Robert S. Coates, and Douglas P. Horton at 50-51.
[33] Ibid at 53-56; Company Exhibit ES-DPH-2.
[34] Ibid at 56-58; Company Exhibit ES-DPH-2.

3. A prudence review of all capital investments conducted at the Company's next base-rate proceeding, conducted at the beginning of each MRP term.[35]
4. An exclusion of major capital investments that accommodate new or expanded customer load not forecasted in the company's five-year capital budget.[36]

Q. You mentioned that the Company's proposed PBR framework would be affected by a I-X Formula and an Earnings Sharing Mechanism. Let's discuss each of those mechanisms. What is an I-X Formula?

A. The I-X formula reflects an externally indexed revenue cap approach that allows the revenue requirement to adjust during the MRP period. In a PBR framework, the I-factor represents a measure of economy-wide inflation, which limits a utility's annual revenue requirement increases in an MRP term to the changes of an external inflation index. The Company proposes an I-factor based on GDP-PI, where the inflation index would be annually adjusted by the annual percentage change of GDP-PI. [37] The annual percentage of GDP-PI is calculated as the average annual percentage change of the most recent four quarterly measures of the GDP-PI as of the fourth quarter of the year. In their proposal, the Company proposes a floor and ceiling to the I-factor, where the I-factor would not exceed 5% or fall below 0%.

[35] Direct Testimony of Douglas W. Foley, Robert S. Coates, and Douglas P. Horton at 53.
[36] Ibid. 58-60.
[37] Ibid at 49-50.

Q. What is the X-factor?

A. The X-factor represents a measure of expected productivity in the utility industry, which represents the impact of the utility industry's productivity growth on cost growth. In other words, an X-factor adjusts the I-factor's economy-wide impact on cost growth (i.e., inflation) against changes to productivity specific to the utility industry. In many PBR jurisdictions, the X-factor is calculated through a Total Factor Productivity (TFP) study, which estimates utility industry productivity through econometric and statistical methodologies that reflect average historical trends in multifactor productivity from a group of peer utilities.[38] The determination of a TFP study can vary widely based on the selection of peer utilities, length of historical analysis, inputs, outputs, and even methodologies. The Company's TFP study calculated a negative X-factor (-1.42%), but recommended a 0% X-factor because a negative X-factor has bad connotations for a utility's efficiency relative to other businesses.[39] In addition, X-factors are subject to alterations in negotiated settlement agreements and regulatory authority determinations in several PBR jurisdictions, such as Hawaii, Alberta, Massachusetts, and the Company's own proposal to set the X-factor to 0% in this rate case.[40]

Nevertheless, the Company's proposal to set the X-factor at 0% sidesteps the question of the utility industry's productivity and effectively subjects the Company's

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[38] "Total Factor Productivity Studies in the Electricity Sector," Pacific Northwest National Laboratory, June 2022, at Page ii, Available at: https://gmlc.doe.gov/sites/default/files/2023-06/Total%20Factor%20Productivity%20Studies%20in%20the%20Electricity%20Sector.pdf.
[39] [39] Direct Testimony of Douglas W. Foley, Robert S. Coates, and Douglas P. Horton at 47-48.
[40] Id.

utility's annual revenue requirement increases in an MRP term to the Company's proposed I-factor and K-bar.

Q. What is an Earnings Sharing Mechanism (ESM)?

A. An ESM is a ratemaking mechanism that shares a utility's earnings in excess of a preestablished threshold above its allowed Return on Equity (ROE) between a utility's ratepayers and its shareholders. In PBR jurisdictions, an ESM can serve as a guardrail for the MRP to provide customers a share of a utility's surplus earnings over allowed ROE, while maintaining utility incentives to pursue cost savings, over the MRP term. ESMs can have a variety of components – such as Symmetry, Dead Bands, Tiers, ROE Calculation Methodology, and Categories of Earnings Eligible for Sharing – that affect the amount and ratio of earnings sharing between the utility and its customers.

Q. How does a K-bar affect the I-factor, X-factor, and ESM in a PBR framework?

A. A K-bar affects the I-factor and X-factor by diluting the cost control features of an I-X formula in a PBR framework. The overall point of an I-X formula is to link a utility's revenue requirement needs to external economic (i.e. the I-factor) and productivity (i.e. the X-factor) trends, thereby giving a utility the opportunity to earn an allowed ROE from its revenue requirement amidst evolving macroeconomic conditions without the need for rate cases in an MRP term. If a utility can grow its rate base from funding sources outside of the I-X formula, then the I-X formula becomes less effective in controlling costs because it applies to a smaller percentage of the utility's overall revenue. Since the Company's proposed K-bar is a rolling three-year historical average of actual capital additions, the K-bar is untethered to the Company's cast-off rates at the beginning of the MRP term.

Because the K-bar's untethers revenues to external conditions via the I-X formula, a K-bar affects the ESM by giving the Company an increased opportunity to earn beyond its allowed ROE via additional revenues. As seen with Alberta's second PBR term in Figure 4, a K-bar frequently increased their utilities' Actual ROE beyond the Allowed ROE's, which would thus apply an ESM to those utilities' actual earnings. The structure of an ESM is even more important if a K-bar is approved because it significantly increases the Company's opportunity to earn beyond its Allowed ROE.

Figure 5: Alberta Utilities' Allowed and Actual ROEs in its Second PBR Term[41]

	2018		2019		2020		2021		2022		Average	
Utility	Pre-K-bar ROE (%)	Post-K-Bar ROE (%)	Pre-K-bar ROE (%)	Post-K-Bar ROE (%)	Pre-K-bar ROE (%)	Post-K-Bar ROE (%)	Pre-K-bar ROE (%)	Post-K-Bar ROE (%)	Pre-K-bar ROE (%)	Post-K-Bar ROE (%)	Pre-K-bar ROE (%)	Post-K-Bar ROE (%)
Fortis	4.41	8.43	4.89	10.14	4.87	10.13	1.50	10.23	0.44	10.50	3.22	9.89
ENMAX	4.51	6.53	6.18	9.31	6.21	9.19	3.67	4.29	2.14	10.21	4.54	7.91
ATCO Electric	7.74	7.85	9.53	10.66	7.63	9.82	8.36	12.85	6.78	14.52	8.01	11.14
EPCOR	7.86	10.81	7.45	11.63	6.64	11.36	4.50	11.44	2.09	10.00	5.71	11.05
Apex	3.66	7.90	4.89	8.72	2.30	8.81	2.30	9.57	0.88	10.79	2.81	9.16
Approved ROE (%)	8.5		8.5		8.5		8.5		8.5		8.5	

Q. Do you agree with the Company's proposed K-bar approach?

A. No. I oppose the Company's proposed K-bar approach because it erodes customer cost control for minimal administrative efficiency gains. As stated above, a K-bar would dilute the I-X formula's ability to regulate cost increases to external economic and productivity conditions in an MRP term. This erosion of cost control is especially dire

[41] Alberta Third PBR Term Decision at 8. Available at: https://www.auc.ab.ca/the-auc-issues-third-generation-performance-based-regulation-decision/

because the K-bar would account for $81 million of the $113 million in additional revenues proposed by the Company's PBR framework.[42]

In Company Exhibit ES-DPH-1, the I-X formula would increase the revenue requirement by approximately $10 million in each year of the MRP term, or $32 million in total.[43] Yet, the Company's total revenue requirement over the MRP would increase by $113 million in additional revenues.[44] Since only $32 million of the $113 million in additional revenues result from the I-X formula, the K-bar thus accounts for 71.7% of proposed additional funding. In effect, the Company is not proposing an I-X formula with supplemental K-bar funding, but rather a K-bar with supplemental I-X formula funding for its PBR framework.

Q. You mentioned that the K-Bar erodes customer cost control in n a PBR framework. Will you please explain how?

A. Yes. The purpose of a K-bar is to give the Company a flexible funding source that allows the Company to invest in system expansion beyond the revenue requirement established in the cast-off rates and I-X formula. The benefit to the Company is a significant reduction in administrative burden largely due to the fact that it must only seek a prudence review of capital expenditures during the MRP once during the next MRP.[45] The K-bar is based on a rolling three-year average of actual capital additions, so any

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[42] Company Exhibit ES-DPH-1 at 1, line 16.
[43] Ibid at 1, line 12.
[44] Ibid at 1, line 24.
[45] Direct Testimony of Douglas W. Foley, Robert S. Coates, and Douglas P. Horton at 53.

capital costs approved in the upcoming MRP term would be “baked into” the next MRP term, in addition to the Company’s rate case proposal and I-X formula costs.

However, the K-bar erodes the primary MRP benefit to customers, cost control. Through a MRP, the Commission dictates the utility’s revenue requirement each year of the term. The Company is given a budget and must manage its costs within that budget. The result is predictable, stable rates for customers and a cost efficiency incentive for the utility. However, because the K-bar allows capital spending outside of the MRP term, the benefits of the MRP to customers are eroded.

Q. The Company proposes to cap each year’s K-bar distribution to 10% above the Company’s forecasted annual capital spending.[46] Does the Company’s proposed cap protect ratepayers?

A. No. the Company’s proposed cap is a paper-thin ratepayer protection because the K-bar would not exceed the Company’s forecasted annual capital spending at any point in the MRP period.[47] While helpful on paper, the 10% cap is not a substitute for actual cost controls that benefit customers. This goes to show that establishing a PBR framework is complicated, and it takes time to consider consequences, both intended and unintended, of various PBR mechanisms.

Q. Will you speak more about the complication of developing a PBR framework?

A. Certainly. There is no single PBR framework – it looks different in every jurisdiction. The needs, and governing regulations and policies, of one jurisdiction will be different

[46] Ibid at 52-53.
[47] Ibid at 53.; Company Exhibit ES-DPH-2 at 1, lines 41-47.

than another jurisdiction. As such, the PBR framework and the mechanisms adopted in one state may be different than in another. There are numerous mechanisms that can be used to incentivize utility actions, or disincentivize other utility actions, reduce regulatory lag, or protect customers. Should a public utility commission determine that it is in the public interest to deal with regulatory lag via a multiyear rate plan, it has several pathways. Moreover, the mechanisms adopted through a PBR framework can interact with each other, often in unforeseen ways. Based on my experience, public utility commissions can take years to develop a PBR framework. More specific to the K-bar, I have significant reservations that the K-bar erodes the benefits of cost control for customers through a MRP and I have not seen that issue sufficiently remedied.

Q. In your experience, do capital recovery mechanisms like the Company's proposed K-bar typically decrease risk to the utility?

A. Yes. All else equal, a utility that has a capital cost recovery mechanism is less risky, from an investment perspective, than a utility without a capital cost recovery mechanism. Typically, during a MRP, the utility's revenue requirement is set for the term of the MRP. The utility has a budget. The utility is thus incentivized to control costs so that it can achieve its authorized rate of return. As I mentioned, the incentive for the utility to control its costs is the primary benefit to customers of a MRP. By allowing the utility to collect incremental capital costs during the term of MRP, the K-bar provides an additional source of revenue, which reduces the utility's financial risk.

Q. What is your recommendation to the Commission?

A. I recommend the Commission reject the Company's proposed K-bar because it is detrimental to ratepayers.

Q. If the Commission chooses to implement a PBR framework with a K-bar, are there any alterations to the K-bar that would help protect ratepayers?

A. If the Commission chooses to implement a K-bar despite its inherent lack of ratepayer protections, I recommend three changes to the Company's K-bar proposal that could help minimize the harm to ratepayers:

1. The company should cap the K-bar's annual distribution to each year's projected investment needs from the Company's most recent Distribution Solutions Plan (DSP), rather than the Company's proposed five-year capital plan.
2. Exclude major capital investments that are not modeled in the Company's DSP from the K-bar.
3. Apply a discount of 15-30% to the K-bar's annual distribution, to limit the imbalance of K-bar funding relative to I-X funding.

Q. Please explain why you recommend capping the K-bar's distribution to the Company's projected investment needs in its DSP?

A. Typing the K-bar to the Company's DSP plan provides the Commission and stakeholders with a separate docket to assess the Company's proposed capital additions. The DSP must be regularly updated to reflect changing conditions. The Company most recently submitted a Distribution Solutions Plan in June 2024, which includes five and ten-year demand forecasts and assessments. The DSP is a more suitable venue than the

Company's general rate case for the Commission and intervenors to assess the Company's forecasts and capex plans to determine what level of investment is necessary for safe, reliable, resilient, and affordable electric service.[48]

Q. Please explain why you recommend excluding major capital investments that are not modeled in the Company's DSP from the K-Bar?

A. The Company proposes to exclude capital additions resulting from co-optimized customer-driven investments, if those investments each year exist and would cause the Company to exceed the K-bar cap in that year.[49] The Company's proposed exclusions are insufficient because they would still be counted in the K-bar's distribution if it does not reach its annual cap. Instead, I recommend excluding all major capital investments that are not modeled in the Company's DSP as a cost control measure that would enable the Commission and stakeholders to review all capital investment costs for prudency. If the unmodeled capital investments represent one-off events (i.e. bespoke projects that are unlikely to be replicated in future years), then their rate impacts should not be baked into rates through the K-bar. If the unmodeled capital investments represent replicable capital investments, then they should not be included in the K-bar until the Commission and intervenors have had the chance to review their prudency through the DSP process.

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[48] Eversource. "New Hampshire Distribution Solutions Plan." Docket No. DE 24-070. Attachment ES-DSP-1. June 11, 2024. Available at: 24-070_2024-06-11_EVERSOURCE_ATT-TESTIMONY-FREEMAN-SCHILLING-NTAKUO-WALKER-RENAUD.PDF

[49] Direct Testimony of Douglas W. Foley, Robert S. Coates, and Douglas P. Horton at 58-60.

Q. Please explain why you recommend applying a discount of 15-30% to the K-bar's annual distribution, to limit the imbalance of K-bar funding relative to I-X funding.

A. Previously I stated that the Company's proposed K-bar presents few opportunities for cost control while accounting for 71.7% of the Company's proposed additional funding. A discount on the annual K-bar distribution would reduce that imbalance and incentivize the Company to acquire additional funding through its cast-off rates at the beginning of an MRP term, which offers the Commission and intervenors a greater opportunity to review and control cost. This approach is used in at least one other PBR jurisdiction, Alberta, which applies a 15% discount on the K-bar's formula.[50] In this case, a discount of up to 30% would send a strong signal for the Company to base their revenue requirement off of external inflation and productivity changes through the I-factor and X-factor respectively rather than a separate K-bar mechanism.

Q. Does this conclude your testimony?

A. It does, thank you.

[50] Alberta Utilities Commission. 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities. October 4, 2023. Decision 27388-D01-2023. p. 126. Available at: https://efiling-webapi.auc.ab.ca/Document/Get/794425