BEFORE THE

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY

Docket No. 26-05-10

APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY D/B/A EVERSOURCE ENERGY TO AMEND ITS RATE SCHEDULES

Pre-filed Direct Testimony of

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On Behalf of

The Office of Consumer Counsel

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Attachment MW-1: Resume of Melissa Whited

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A My name is Melissa Whited. I am a Vice President at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics, Inc.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the electric and gas industries.

Q Please summarize your professional and educational experience.

A I have 15 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models and rate design. I have been an invited speaker at numerous industry conferences, including as a panelist for the National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Rate Design at the 2021 Winter Policy Summit and at the 2018 Annual Meeting.

I have sponsored testimony or expert reports before 18 utility regulatory commissions in the United States, three Canadian provinces, and the Federal Energy Regulatory Commission. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. My resume is attached as Exhibit MW-1.

Q Have you previously testified before the Connecticut Public Utilities Regulatory Authority?

A No, I have not.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Office of Consumer Counsel ("OCC").

Q What is the purpose of your testimony?

A In this testimony I address certain aspects of Eversource Energy's ("Eversource" or "Company")'s allocated cost of service study ("ACOSS"), revenue allocation, and rate design proposals. The absence of discussion of other topics in this testimony should not be construed as support for, or opposition to, the Company's positions.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your conclusions.

A My conclusions are as follows:

- The Company's use of the minimum system method for classifying substantial portions of its distribution system in its ACOSS does not accurately reflect cost-causation principles and inflates cost allocations to residential customers. In

addition, the Company fails to make any adjustments to class demands to account for the load carrying capacity of the minimum distribution system.

- The Company's classification of advanced metering infrastructure ("AMI") meter costs as 100 percent customer-related does not reflect cost causation or benefit accrual, specifically the fact that the AMI investment will enable energy savings and demand reductions.
- The Company's traditional class non-coincident peak ("NCP")n allocators ignore how class mix and peak timing differ from one feeder and substation to the next.
- Despite providing lower rates during winter months that would help incentivize heat pump adoption, the Company's proposed residential heat pump rate (Rate 6) is not the most effective way to ensure efficient system usage and is not based on adequate analysis, potentially leading to cost shifts.
- The Company's proposed Economic Development Rate ("EDR") rider lacks sufficient safeguards, does not meaningfully incentivize load flexibility to support system efficiency, and includes a non-transparent and administratively burdensome process to determine the discount level.

Q What are your recommendations?

A First, with respect to the Company's ACOSS, I recommend that the Authority direct the Company to utilize cost of service methods that better reflect cost causation. Specifically, I recommend that the Authority:

- Reject the Company's minimum system method and direct the Company to classify distribution costs using the basic customer method in which only meters, services,

meter reading, and billing costs are classified as customer-related, until more granular analysis can be performed to capture customer density.

- Direct the Company to develop a customer density approach to classification, similar to the one approved by the Ontario Energy Board. Customer-related percentages would vary by density category (urban, mixed, and rural), measured in customers per circuit mile. This analysis should be submitted with its next rate case application.
- If the Authority approves the minimum system method, it should direct the Company to reduce each class's non-coincident peak demand by the load-carrying capability of the minimum system. This is consistent with the Authority's determination in Docket No. 24-10-04 and avoids charging the residential class twice for the same capacity.
- Direct the Company to classify AMI meter costs as 38 percent customer-related, 47 percent demand-related, and 15 percent energy-related, rather than 100 percent customer-related. This classification is based on the present value of AMI benefits quantified in the Company's own benefit-cost analysis, excluding Carbon Reduction and System Costs Avoidance.
- Direct the Company to develop distribution allocators based on AMI data for its next base rate case. Specifically, the Company should retain hourly AMI interval data in a form that can be aggregated by substation, feeder, and line transformer; and file an equipment-level allocation study alongside its conventional cost of service study. The study would allocate substations on class contributions to substation peaks, primary lines on class contributions to feeder peaks, and line transformers on class contributions to transformer peaks.

With respect to the Company's rate design proposals, I recommend that the Authority:

- Reject the Company's proposed Rate 6 and instead adopt a cost-based, seasonal opt-in time-of-use ("TOU") rate that includes time-differentiated distribution, transmission, and supply charges.
- Reject the Company's proposed EDR rider and instead adopt one based on UI's EDR with additional modifications. Specifically, the EDR should:
  - Exclude data center loads from qualifying for the rate;
  - Require EDR customers to take service on an enhanced TOU rate, to be filed by Eversource within six months of the Authority's decision in this proceeding;
  - Adopt fixed discount levels, including a 20 percent discount for facilities sited in an Environmental Justice Community and a 15 percent discount for facilities sited in other communities, with a discount cap of 50 percent of the net present value of incremental revenues.

III. SUMMARY OF EVERSOURCE'S RATE PROPOSALS

Q Please summarize the rate increases proposed by the Company for residential customers.

A For Rate 1 (standard residential) customers, the Company proposes to increase the monthly customer charge from $9.63 to $12.36 (a 29 percent increase) and the volumetric distribution charge from $0.05844 to $0.12196 per kWh (a 109 percent increase).[1] For a customer using 700 kWh per month, the proposed rate increase would result in an 18.05 percent bill increase, equivalent to $37.22 per month.[2]

[1] Exh. CLP-RATES-2.2.
[2] Exh. CLP-RATES-2.2.

For Rate 7 (time-of-day) customers, Eversource proposes to increase the monthly customer charge from $9.62 to $12.36 (a 29 percent increase) and the volumetric distribution charge from $0.05513 to $0.11966 per kWh (a 117 percent increase).[3] For a customer using 700 kWh per month, the proposed rate increases would result in an 18.69 percent bill increase, equivalent to $33.62 per month.[4]

Q Does the Company propose any new rate designs?

A Yes. The Company proposes a new residential heat pump rate (Rate 6), which provides a discount on winter usage above 700 kWh for customers switching from delivered fuels to heat pumps for heating.[5] The Company also proposes a new Economic Development Rate, which provides a rate discount for certain new and expanded industrial loads.[6]

Q What principles guide your rate design analysis and recommendations?

A My analysis and recommendations are primarily guided by the principles enumerated in James Bonbright's *Principles of Public Utility Rates*, which are widely used in the industry and can be summarized as follows:[7]

1. **Sufficiency:** rates should yield revenues sufficient to recover utility costs.

2. **Fairness:** rates should fairly apportion costs among different customers and avoid "undue discrimination" in rate relationships.

[3] Exh. CLP-RATES-2.2.
[4] Exh. CLP-RATES-2.5.
[5] Exh. CLP-RATES-1, at 31.
[6] Exh. CLP-RATES-1, at 24-25.
[7] James Bonbright. 1960. Principles of Public Utility Rates. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/.

3. **Efficiency:** rates should provide efficient price signals and discourage wasteful usage.

4. **Customer acceptability:** rates should be relatively stable, predictable, simple, and easily understandable.

IV. COST OF SERVICE STUDY

Q What is the purpose of a COSS?

A A COSS estimates how much of the utility's revenue requirement each customer class causes. It assigns that revenue requirement to rate classes based on the costs each class imposes on the system.

Q How is a COSS performed?

A An allocated cost of service ("ACOS") study typically follows three steps. First costs are functionalized, which means that the utility plant and expenses are separated according to the primary functions served. Second, the functionalized rate base and operating costs are classified by their main cost driver, primarily demand, energy, or customer. Finally, the costs are either directly assigned to customers or allocated among customer classes using allocation factors based on their classification. Allocation factors primarily consist of various measures of peak demand, energy usage, or the number of customers.

Q How do analysts determine the appropriate approaches to cost classification and allocation?

A When selecting classification factors or allocators, the goal is to fairly allocate costs among different customer classes based on cost causation. Cost causation reflects the notion that the customer or set of customers that caused a cost should pay for the cost. To

determine cost causation, analysts often rely on economic theory and power system engineering considerations. These judgments are rarely clear-cut. Reasonable analysts can and do reach different conclusions about what drives a given cost.

Q How should the Authority use a COSS in this proceeding?

A The Authority should exercise judgement when using a COSS because it is an imprecise tool. The analyst makes many subjective choices about functionalization, classification, and allocation, and each one can change the results substantially. A COSS should therefore be one of several things that guide revenue allocation and rate design, not the deciding factor.

Q In your view, has the Company selected appropriate ACOS methods?

A No. I have three primary concerns with the Company's ACOS methods:

1) The Company's meter classification does not reflect AMI cost causation;

2) The Company classifies portions of the distribution system as partially "customer-related" based on a flawed minimum system methodology; and

3) The Company's demand allocation method for distribution system infrastructure does not reflect localized variance in cost causation.

A. The Company's classification of AMI meter costs fails to reflect their system benefits

Q Describe the extent of AMI deployment in the Company's territory.

A Currently, nearly all Eversource meters in Connecticut use Automated Meter Reading ("AMR") technology, which means that data collection depends on a company vehicle driving within range of the meter.[8] Eversource is currently in a transition period from

[8] Exh. CLP-ELP-4, at 349.

legacy AMR technology to AMI[9] and has proposed a six-year implementation plan for deploying AMI meters across the state.[10]

Q How does the Company propose to classify and allocate AMI costs?

A The Company states that it "is proposing to recover eligible AMI capital costs through the proposed Performance Based Multi-Year Rate Plan ("PBMRP") capital funding mechanism," and that costs would be allocated to rate classes on the basis of class distribution revenue (class allocation factors) described in the tariff.[11] However, in the next rate case, AMI costs would presumably be moved to base rates, and the Company has not indicated that it would deviate from its standard approach of classifying metering and related costs as customer-related.[12]

Q Do you have concerns with the classification of AMI meter costs as entirely customer-related?

A Yes. Classifying traditional meters as customer-related is reasonable, because their primary function is to measure each customer's usage for billing. AMI meters have much greater capabilities, including supporting time-varying rates, providing granular voltage and load data, and enabling voltage optimization. Those additional capabilities provide energy and demand savings to the system as a whole, rather than just serving as a customer billing tool. Because the Company is about to replace meters across its entire territory, now is the time to provide guidance to ensure that AMI costs are classified appropriately.

[9] In contrast, Eversource in Massachusetts began broad AMI deployment beginning in 2025. As of October 2026, Eversource's Massachusetts website indicates 500,000 smart meters installed, representing approximately one-third of its 2028 deployment goal. https://www.mass.gov/info-details/grid-modernization-and-ami-resources
[10] Exh. CLP-AMI-2, pp. 9-12.
[11] Response to OCC-740.
[12] Exh. CLP-ACOS-1, at 4:5-7.

Q Has the classification of advanced meter costs been addressed in cost allocation literature?

A Yes. The Regulatory Assistance Project addresses the issue directly. It explains that the main purpose of meters was once customer billing, but that "advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and line loss reduction, which provides a system energy benefit." It concludes that "the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs."[13]

Q Does Eversource's own analysis show that AMI enables services beyond customer-related functions?

A Yes. Among the benefits listed in the Company's benefit categories in its Benefit Cost Analysis of AMI are system cost avoidance, volt/var optimization ("VVO"), and time varying rates.[14] The Company therefore expects AMI to:

- reduce peak demand by enabling more sophisticated time-varying rates, thereby avoiding or deferring system costs that would otherwise increase with peak load; and
- reduce distribution losses and energy consumption through voltage optimization, using voltage data from AMI meters.

These operational improvements that Eversource recognized in its benefit cost analysis clearly extend the role of AMI beyond traditional metering, which provides none of these

[13] Lazar, J. et al., *Electric Cost Allocation for a New Era: A Manual.* Montpelier, VT: Regulatory Assistance Project (2020), at 18.
[14] CLP-AMI-2, Figure 22, p. 91.

functions. Its cost classification should therefore recognize that the investment is "largely justified by services other than billing."[15]

Q How do you recommend that Eversource classify AMI meter costs?

A AMI meter costs should be classified in proportion to the net present value of the benefits the Company has quantified, with each benefit assigned according to what drives the cost it avoids. I recommend that benefits from metering, billing, and customer account functions be classified as customer-related, benefits from voltage optimization and reduced line losses as energy-related, and benefits from peak reduction, avoided VVO line sensors, and improved outage restoration as demand-related.

Q What percentage of AMI meter costs should be classified as demand-related and energy related?

A The Company provides the present value of AMI benefits in Exhibit CLP-AMI-3. I have reproduced these benefits in the table below, excluding carbon reduction, which is not a utility system benefit, and system costs avoidance, which is primarily the avoided cost of the customer information system and does not depend on the AMI meters themselves.

[15] Lazar, J. et al., *Electric Cost Allocation for a New Era: A Manual.* Montpelier, VT: Regulatory Assistance Project (2020), at 157.

Table 1. Classification of AMI Costs According to System Impacts

Benefit Category	Benefits (NPV $M)	Recommended Classification
Meter Reading	$21.20	Customer
Avoided Meter Capital	$160.30	Customer
Remote Connect/Disconnect	$32.20	Customer
No Trouble Found Calls	$5.70	Customer
Reduced Bad Debt	$74.50	Customer
Reduced Soft Close Loss	$24.30	Customer
VVO	$163.80	Energy $106.2 / Demand $57.6
Time-Varying Rates	$23.90	Demand
Asset Optimization	$96.40	Demand
Advanced Engineering Analysis	$38.70	Demand
Avoided Connectivity Survey	$6.70	Demand
Improved Restoration – Significant Storms	$162.40	Demand
Improved Restoration – Blue Sky	$2.50	Demand
Reduced Theft and Non-Technical Line Loss	$16.50	Energy
Customer-related	**$318.20**	**38%**
Demand-related	**$388.20**	**47%**
Energy-related	**$122.70**	**15%**

Source: Avoided costs from Exhibit CLP-AMI-3, Figure 7. Classification is my own.

Thus, AMI meter costs should be classified as 38 percent customer-related, 47 percent demand-related, and 15 percent energy-related.

Q Have other Commissions approved similar AMI meter classifications?

A Yes. The Maryland Public Service Commission approved "a benefits approach for allocating AMI costs among rate classes" in 2016, when it approved a proposal to assign 25% of AMI costs using a customer-based allocator, 37.5% using a demand-based allocator, and 37.5% using an energy-based allocator in Pepco's distribution rate case.[16]

[16] In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy (Hereafter, "MD PSC, Case No. 9418"). Order No. 87884. November 15, 2016. https://psc.maryland.gov/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf at 105-106.

The approved proposal was based on the fact that an early report on AMI benefits assigned just over 75% of the benefits to energy and demand management outcomes, justifying a customer-, demand-, and energy-based allocation.[17] The PSC concluded that the "hybrid approach most fairly spreads the costs and related benefits of AMI throughout the Pepco service territory."[18]

B. The Company's minimum system method to classify distribution system costs does not reflect cost causation

Q What is a minimum system study?

A A minimum system study, or minimum system method, is a cost analysis that estimates what the cost of the distribution system would be if the total system inventory was composed of the smallest equipment size.

Q How does the Company use the Minimum System Method to classify distribution costs?

A The Company's Minimum Distribution System ("MDS") Study separates the costs of distribution facilities into customer-related and demand-related components.[19] Under this approach, Eversource first identifies the cost of the hypothetical minimum sized system (including minimum sized poles, conductors and conduits, and transformers) required to connect customers. It then classifies the portion of distribution costs representing the minimum system as customer-related, while the difference between total system costs and customer-related costs is classified as demand-related.[20] Table 2 below provides the

[17] MD PSC, Case No. 9418. Direct Testimony of Shelley Norman. July 6, 2016. https://webpscxb.pscmaryland.com/DMS/case/9418 Item No. 33. At 21-23.
[18] MD PSC, Case No. 9418. Order No. 87884. November 15, 2016. At 106.
[19] Exhibit CLP-ACOS-1, p. 4.
[20] Exh. CLP-ACOS, at 4:14-5:13.

resulting split between customer-related and demand-related costs resulting from this method.[21]

Table 2. Minimum system study classification factors

Account Number		Demand	Customer
364	POLES - PRIMARY	56.1%	43.9%
364	POLES - SECONDARY	40.6%	59.4%
365	PRIMARY OH LINES	87.5%	12.5%
365	SECONDARY OH LINES	81.2%	18.8%
366, 367	PRIMARY UG LINES	91.2%	8.8%
366, 367	SECONDARY UG LINES	89.8%	10.2%
368	OH TRANSFORMERS	57.1%	42.9%
368	UG TRANSFORMERS	80.9%	19.1%

Q How does the Company define customer-related costs?

A The Company defines customer-related costs as those that vary with the number of customers on the system and are independent of the customer's usage. The Company also asserts that customer-related costs include a portion of the distribution system identified with the Minimum Distribution System.[22]

Q Is it appropriate to classify the Minimum Distribution System as customer-related?

A No. While these costs are not directly related to customer demand, they are similarly not directly related to the number of customers on the system. Rather, these costs are primarily driven by the geographic dispersion of customers. As Professor Bonbright explains, the primary justification put forward for classifying the costs of this "phantom, minimum-sized distribution system" as customer related is that these costs vary directly with the area of the distribution system or the lengths of the distribution lines and thus are thought to vary indirectly with the number of customers.[23] However, he noted that the

[21] Exh. CLP-ACOS-1 at 5, Table 1.
[22] Exh. CLP-ACOS-1 at 4:3-7.
[23] James Bonbright. 1961. Principles of Public Utility Rates, pp. 347-348.

correlation between the area (or mileage) of a distribution system and the number of customers is "very weak," because "it makes no allowance for the density factor (customers per linear mile or per square mile)," and that "an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system."[24]

In other words, using customer counts as the allocator for the minimum system does not capture the higher cost of serving sprawling or remote populations relative to dense urban centers. For example, if the Company adds a new residential customer with a negligible level of demand in a populated area, the additional distribution costs to serve that customer—aside from dedicated customer infrastructure—would generally also be negligible, because the system has already been constructed to serve customers in that area. In contrast, a new customer located in a rural area may require investments in additional distribution system poles and wires to extend service to the customer's residence. These hypotheticals illustrate that distribution system costs associated with connecting a new customer to the grid tend to vary more with geographic density than the number of customers.

Q How did Professor Bonbright recommend minimum distribution system costs be classified?

A Professor Bonbright argued that the costs of the minimum system should be excluded from demand-related costs, but also that classifying them as customer-related is "clearly

[24] *Id.,* at 348.

indefensible."[25] Instead, in Bonbright's opinion, these costs "should be recognized as a strictly unallocable portion of total costs."[26]

Q Are there any alternative methods that would better account for customer density in cost of service models?

A Yes. The Ontario Energy Board approved the use of a density factor, calculated as customers per kilometer of line,[27] to inform categorization of customer-related and demand-related costs. The Ontario Energy Board's examination identified low, medium, and high customer density "bins" to establish the percentage of customer-related costs. Transformers were part of the cost pool subjected to the minimum plant categorization based on customer density.[28] This method could also be applied to Eversource's system in the future.

Q Do you have any other concerns regarding the minimum system method?

A Yes. The minimum system includes poles, conductors, and transformers that are capable of serving some amount of demand. In some cases, the "minimum system" as defined by the utility may even be capable of serving most or all of a typical residential customer's peak demand. This infrastructure is classified as customer-related, while the remaining demand-related costs are allocated using each class's full non-coincident peak demand, including the portion the minimum system already serves. Unless each class's demand allocator is reduced to account for the load-carrying capability of the minimum system, classes with many small customers will be charged twice for the same capacity: once through the customer classification and again through the demand allocator. The

[25] *Ibid.*
[26] *Ibid.*
[27] Ontario Energy Board, EB-2007-0667, Board Staff Discussion Paper, p. 12.
[28] *Ibid.*

residential class bears most of this double counting, because it has the most customers and the lowest demand per customer.

This issue was identified by the Staff of the Ontario Energy Board, who wrote that "[a] Minimum System has a certain load carrying capability which can be viewed as being demand-related. As a result, the customer-related costs will have a demand component in them. If no adjustment is made, some customers (e.g., small users) may be allocated a disproportionate share of demand-related costs. If the Minimum System Method is preferred for categorization, Staff would recommend that distributors be required to also adjust for the [Peak Load Carrying Capacity] of the assumed Minimum System."[29]

Q Has the Authority previously approved a load carrying adjustment for the minimum system?

A Yes. In Docket No. 24-10-04, the Authority determined that "it is appropriate to use the Company's load-carrying capacity adjustment values for poles and conductors," as well as conductors and line transformers.[30]

Q Did Eversource implement such an adjustment?

A No. When asked whether the Company "considered the minimum system's load carrying capacity when allocating demand-related costs," the Company responded that it did not "revise the demand classification percentage based on the minimum system carrying

[29] Ontario Energy Board. Cost Allocation Review: Staff Discussion Paper. September 2005. At 21-22. Available at https://www.oeb.ca/documents/cases/EB-2005-0317/staffdiscussionpaper_160905.pdf.
[30] Final Order in Docket 24-10-04, October 28, 2025, pp. 198-199.

capacity," and that the ACOS study relied on the "traditionally applied MDS approach as applied in prior rate cases and as per the NARUC Manual."[31]

Q Do you agree that the Company applied the minimum system method in a manner consistent with the NARUC manual?

A No. The NARUC Manual states that "[w]hen using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost."[32]

Q What are your recommendations for the minimum system method?

A I recommend that the Authority reject the minimum system method. Instead, my primary recommendation for this proceeding is that the Authority adopt the basic customer method, under which the costs that are directly classified as being customer-related are the costs of metering (including the service drop), meter reading, and billing. In some cases, the cost of the secondary line transformer is also included. This method limits customer-related costs to those clearly related to the cost associated with serving a new customer. All other costs should be classified as demand-related until the Company completes a study that appropriately allocates "minimum system" costs according to customer density. To accomplish this, I recommend that the Authority direct Eversource to develop a geographic dispersion allocator, similar to that approved for Ontario's Minimum System Studies, where the Company applies density bins (e.g., urban, rural, and mixed) measured in customers per mile to differentiate customer-related cost percentages.

[31] OCC-738(a).
[32] NARUC (1992) Electric Cost Allocation Manual, at 95.

If the Authority chooses to approve the use of the minimum system method for this case or future cases, it should require the Company to adjust each class's non-coincident peak demand by the minimum system's load carrying capacity per customer. Failure to do so would result in double counting because the minimum system already serves a large portion of the residential class's demand, and a portion of other classes' demands. The demand served by the minimum system should not be used again to allocate costs to customers through the use of unadjusted NCP allocators.

Q What is the impact of using the basic customer method in which FERC Accounts 364-368 are classified as 100 percent demand-related?

A The Company indicates that the basic customer method would result in an increase in the rate of return under current rates of 0.85 percent for Schedules 1 and 7, as well as an increase in the rate of return for the unmetered and street lighting classes. Other classes would see a reduction in their rate of return. These impacts are shown in the table below.

Table 3. Impact of adopting the basic customer method

	Minimum Dist. System Current Rates		Basic Customer Method Current Rates		
Rate Codes	**Rate of Return**	**Class to Total**	**Rate of Return**	**Class to Total**	**Change**
Rate 1 & 7	0.4%	0.3	1.2%	1.1	0.85%
Rate 5	-0.2%	-0.2	-0.3%	-0.3	-0.05%
Rate 18	-12.1%	-11.5	-12.4%	-11.8	-0.26%
Rate 27, 27A, 30, 30A & EV-S	5.0%	4.8	3.8%	3.6	-1.20%
Rate 29	-4.9%	-4.6	-5.6%	-5.3	-0.71%
Rate 35, 37 & EV-M	2.9%	2.7	0.9%	0.8	-1.95%
Rate 39	-3.5%	-3.3	-4.4%	-4.2	-0.95%
Rate 40	5.2%	5.0	3.7%	3.5	-1.53%
Rate 41	4.2%	4.0	1.9%	1.8	-2.26%
Rate 55	0.4%	0.4	-1.2%	-1.1	-1.59%
Rate 56 & EV-L	1.7%	1.7	-0.1%	-0.1	-1.84%
Rate 57	-0.8%	-0.8	-2.2%	-2.1	-1.37%
Rate 58	0.5%	0.5	-1.1%	-1.0	-1.64%
Rate 115	-0.7%	-0.7	0.4%	0.4	1.12%
Rate 116 & 117	-5.8%	-5.5	-5.6%	-5.3	0.16%
Rate 119	162.3%	154.2	145.0%	137.8	-17.32%
Total	**1.05%**	**1.0**	**1.05%**	**1.0**	

C. The Company's allocation method for distribution plant costs is outdated

Q How does the Company allocate demand-related distribution costs?

A The Company allocates demand-related distribution costs using the relative class non-coincident peaks.[33]

Q Is it considered best practice to use traditional NCP allocators for distribution plant in today's landscape of cost of service methods?

A No. The Company asserts that it relies on "best ACOS practice methods"[34] but traditional NCP allocators fail to account for variations in when class peaks occur and when

[33] Exh. CLP-ACOS-1, at 6:4-7.
[34] Exh. CLP-ACOS-1, at 1:9-11.

individual feeder and substation peaks occur. A more granular approach is needed, which adoption of AMI will facilitate.

Q How can AMI data better align cost allocation with cost causation?

A Understanding localized cost causation addresses the variance in customer class compositions at different feeders. One circuit may be utilized mostly by the residential class, while another on the same substation is used predominantly by the industrial class. AMI interval data can map directly onto specific substations and feeders, allowing the Company to calculate the exact coincidence factor of each customer class at that specific grid asset. That way, the classes driving local capacity investments bear the appropriate share of each asset's cost.

Q What do you recommend regarding updates to distribution allocation practices in the Company's cost of service studies?

A I recommend the Authority direct Eversource to develop more sophisticated allocation practices by using AMI data to measure class contributions to individual distribution feeder and substation peak loads. By shifting from average-coincident assumptions to localized data, the Company can better assign costs in line with causal contribution. AMI data can also delineate minimum system requirements from peak capacity requirements, so that the Company can classify infrastructure costs into customer-, energy- and demand-related components accordingly.

Specifically, I recommend that the Authority direct the Company to design its AMI data systems so that, by its next rate case, it can allocate distribution plant more accurately. Specifically, substations (FERC Account 362) would be allocated based on class contribution to substation peaks; primary lines (Accounts 364-367) would be

allocated based on class contribution to feeder peaks; and line transformers (Account 368) would be allocated on class contribution to transformer peaks. Each allocator would be weighted by the installed cost of the equipment involved. This ties cost responsibility to the loads that drive equipment sizing decisions, rather than to a class-wide statistic that may never coincide with any local distribution system constraint.

Thus, I recommend that the Authority direct the Company to (1) retain hourly interval data from AMI meters in a form suitable for equipment-level aggregation, and (2) in its next base rate case, file an equipment-level allocation study alongside its conventional class cost of service study, so the Authority can compare the results before adopting a new method.

V. RESIDENTIAL HEAT PUMP RATE (RATE 6) PROPOSAL

Q Please summarize the Company's proposal for Rate 6.

A Rate 6 is a whole-house rate that would provide a discounted rate for incremental winter load associated with new air source heat pumps. According to the Company, the purpose of the proposed rate is to drive heat pump adoption, which would improve system utilization in winter months,[35] and to support affordability for customers who currently heat with delivered fuels.[36]

Table 4 compares the proposed Rate 6 to the standard residential Rate 1 as each has been proposed by the Company in this proceeding.

[35] Exh. CLP-RATES-1, at 34.
[36] Response to CLF-003a.

Table 4. Comparison of Eversource proposed Rate 1 and Rate 6 Charges

Distribution Rate Component	Rate 1 (Standard)	Rate 6 (Heat Pump)
Customer Charge ($/month)	$12.36	$30.95
Energy Charge ($/kWh)		
Block 1 - All non-winter usage and winter usage ≤ 700 kWh	$0.12196	$0.09431
Block 2 - Winter usage > 700 kWh	$0.12196	$0.07517

Q Do you support offering lower winter rates to heat pump load?

A Yes. The Company's system is summer-peaking, meaning that system costs are primarily driven by summer peak demand, while incremental winter load does not contribute as much to the need for new distribution infrastructure. Heat pump load, which is concentrated in winter months, can help improve system efficiency by spreading the fixed costs of the system across greater volumes of sales, thereby putting downward pressure on rates for all customers. Lower rates during winter months can help incentivize heat pump adoption and accelerate the addition of heat pump load.

Q Do you have any concerns with the design of the Company's proposed Rate 6?

A Yes. I have two main concerns with the design of Rate 6 as proposed. First, the rate is not revenue neutral and will result in cost shifts to other customers. Second, the proposed eligibility requirements will undermine the objectives of the rate.

A. Eversource's proposed Rate 6 will result in cost shifting

Q Please describe the three distribution rate components of Rate 6.

A Rate 6 has three distribution rate components: a fixed monthly customer charge; a Block 1 volumetric energy charge, which applies to all non-winter usage and to the first 700 kWh of usage per month in the winter; and a new Winter Block 2 volumetric energy

charge, which is the discounted rate applied to usage above 700 kWh/month during the November through March heating season.[37]

The customer charge is designed to recover the Company's estimated marginal customer costs and is set at $30.95 per month. This high customer charge lowers the amount of costs recovered through volumetric charges,[38] resulting in the Rate 6 Block 1 charge ($0.09431/kWh) being approximately 23 percent lower than the Rate 1 energy charge ($0.12196/kWh). The Company explains that the higher customer charge is meant to recover the share of the class revenue requirement associated with load that existed prior to any incremental heat pump load, so that the resulting volumetric rate provides a basis for designing rates for the incremental heat pump load.[39]

Q How did the Company determine the appropriate threshold for discounted Block 2 charges?

A The 700 kWh threshold for the Winter Block 2 charge is based on the average annual usage of the median Rate 1 customer.[40] The Company states that it did not design the Block 2 price as a discount from the Block 1 rate; instead, the Company built the price up from marginal costs: it added the marginal cost of serving load (a subtotal of marginal facilities cost plus marginal energy cost, totaling $0.04152/kWh) to a "reduced reconciliation adjustment" of $0.03365/kWh to arrive at a Winter Block 2 rate of $0.07517/kWh.[41] Specifically, the reconciliation adjustment is scaled down by a "System

[37] Exh. CLP-RATES-1, at 31.
[38] Exh. CLP-RATES-6.
[39] Response to OCC-477.
[40] Exhibit CLP-RATES-1, at 34, lines 5-7.
[41] Exhibit CLP-RATES-6.

Peak Coincidence Factor" of 63.7%, which is the ratio of the coincidence factor with space heating (25.6%) and the coincidence factor without space heating (40.1%).[42]

Q Is the proposed Rate 6 revenue neutral and cost-reflective?

A The Company's proposed Rate 6 is not revenue neutral with Rate 1. Under the Company's rate design approach, Rate 6's increased monthly customer charge enables a lower Block 1 rate.[43] However, the Block 2 discount is not counterbalanced with increases in other rate components. While the lower Block 2 rate may reflect the lower marginal cost of winter usage, the summer rates are not adjusted upwards to similarly reflect the higher marginal cost of summer usage. This approach results in a rate that is not revenue neutral. Additionally, the revenue impact of the Block 2 rate also depends on whether the Company's assumptions about the load billed at the Block 2 rate prove correct. The design of the discount assumes that space heating has a low system peak coincidence factor of 25.6%.[44] However, this metric is based on load research on customers under Rate 5, which is a legacy rate more likely to reflect resistance heating load than heat pump load. Heat pumps have different load characteristics than resistance heating. A different system peak coincidence factor could undermine the cost reflectivity of Rate 6.

Q Why is it important for Rate 6 to be revenue neutral?

A In theory, as long as a rate is set to recover at least the marginal cost associated with new load, additional load on the system will not result in higher costs for existing load. However, Rate 6 has not been designed in a way that reliably distinguishes new heat

[42] Exhibit CLP-RATES-6. Figures as listed are rounded and derived from the Company's MCOS study.
[43] Exh. CLP-RATES-6.
[44] Exh. CLP-RATES-6.

pump load from existing load on the system. Instead, under Eversource's proposal, all winter-month consumption above 700 kWh would be billed only at the discounted Winter Block 2 rate, regardless of whether that consumption comes from a heat pump.

Despite claiming that the average usage for customers without heat pumps is approximately 700 kWh, the Company explains that it cannot differentiate which customers have or do not have heat pumps or isolate heat pump load from a customer's other usage.[45] This means that the 700 kWh threshold is not based on any analysis of customer load with or without heat pumps, and the Company has not provided sufficient evidence that the 700 kWh threshold is a reasonable demarcation between heat pump and non-heat pump load. As a result, any Rate 6 customer whose winter usage exceeds 700 kWh will receive the discount on that usage, even if heat pump load accounts for only a portion of it.

Q Does the design of Rate 6 risk cost shifting to other customers?

A Yes. A Rate 6 customer using 900 kWh/month in the winter would pay only the discounted Winter Block 2 rate on the 200 kWh above the threshold, agnostic of which end use drives that consumption. To the extent that this usage has a higher coincidence factor than what the Company assumed in designing the rate, Rate 6 will under-recover the costs those customers impose on the system, shifting the recovery of these costs to all customers. Further, the higher-usage customers who would benefit most from this design

[45] Response to CLF-001.

tend to have higher incomes (e.g., customers with larger homes or EVs), meaning that the cost shift also has negative equity implications.[46]

Q Does Rate 6 effectively incentivize shifting electricity usage to off-peak periods?

A No. Rate 6 is designed to make heat pump ownership more affordable when heat pump electricity usage is highest. However, a heat pump owner who also charges an EV and enrolls in Rate 6 would have no price incentive to shift that charging to off-peak periods. The Company states that the time-of-day Rate 7 "would be expected" to incentivize EV charging during off-peak periods but it has not evaluated how Rate 6 participation would interact with this expectation.[47] The Company also states that it considered two-block and three-block TOU variants but rejected them on complexity or cost basis grounds,[48] and that it did not evaluate adding seasonality to its existing TOU rate due to complexity concerns.[49]

B. Eversource's proposed eligibility requirements for Rate 6 undermine the rate's objectives

Q Which customers would be eligible for Rate 6?

A Rate 6 would be available to residential customers who switch from delivered fuel to an air-source heat pump on or after January 1, 2026.[50] Customers with electric resistance heating would not be eligible because they already have a strong financial incentive to switch to heat pumps.[51] Customers switching from natural gas service would also be

[46] High-income and EV ownership: Wang, Jiacheng, Harper, D., Hendrickson, C. 2026. Changing US electric vehicle ownership socioeconomic characteristics. *Transportation Research Interdisciplinary Perspectives, Vol. 35.* https://www.sciencedirect.com/science/article/pii/S2590198225004671.
[47] Response to OCC-476b.
[48] Response to OCC-478.
[49] Response to OCC-476b.
[50] Exh. CLP-RATES-1, at 31-32.
[51] Exh. CLP-RATES-1, at 36-37.

ineligible: the Company asserts that conversion from gas heating would increase the household's total energy costs at current prices, which would defeat the core purpose of Rate 6 as an affordability measure.[52]

Q Why do Rate 6's eligibility requirements undermine its own goal of improving winter system utilization?

A The Company's eligibility requirements would exclude customers who convert from gas heating to heat pumps from Rate 6. The Company justifies this exclusion by stating that "the rate is targeted at conversions that reduce the customer's total household energy costs" and a conversion from gas to a heat pump "typically increases the household's total energy bill at current prices."[53] However, a heat pump rate designed to lower winter electric heating costs such as Rate 6 would help reduce energy costs for customers who are converting from gas heating to a heat pump, and thus would not necessarily mean that the conversion would increase a household's total energy costs. Notably, the Company's Massachusetts affiliate, NSTAR Electric, estimated that a gas heating customer switching to a heat pump would reduce total energy costs by approximately four percent under its seasonal heat pump rate.[54]

The Company's ultimate goal of making heat pump ownership more affordable to improve winter system utilization and reduce overall system costs does not depend on which fuel a customer heated with before converting. By barring gas customers who convert to heat pumps from Rate 6, the Company would forgo additional load from these

[52] Response to CLF-002.
[53] Response to CLF-002.
[54] Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of Residential Seasonal Heat Pump Rates, D.P.U. 25-55, Order at 6 (July 29, 2025), available at: https://www.mass.gov/doc/25-55-order/download

customers that would contribute to higher system utilization during winter months, helping to drive down rates for all customers.

C. The Authority should adopt a cost-based, seasonal TOU electrification rate instead of Eversource's proposed Rate 6

Q What do you recommend regarding the Company's proposal for Rate 6?

A I recommend that the Authority reject Rate 6 as filed and instead direct the Company to adopt a cost-based, seasonal TOU rate that includes time-differentiated distribution, transmission, and supply charges. This rate should be designed to incentivize flexible electrification load but would be available to all residential customers. The rate should also be revenue neutral with Rate 1, reflect the seasonality of costs on the Company's system, and provide price signals for customers to shift load out of peak hours. Because the rate is cost-reflective and revenue-neutral, any residential customer could enroll without raising cost shift concerns. This would also eliminate the administrative burden and costs associated with confirming heat pump installation and prior heating fuel.

Q Please describe the seasonal element of your proposed rate.

A My proposed seasonal TOU rate would reflect Connecticut's status as a summer-peaking system by setting higher rates in the summer and lower rates in the winter. Because the Company must build its system to meet the maximum peak demand of its customers, it is reasonable to recover a larger portion of demand-related distribution costs during summer months (June through September), when peak demand is most likely to occur. About 80 percent of the Company's annual probability of peak falls in July and August, with less than 1 percent falling in December through January.[55] Additionally, ISO-NE capacity

[55] Exhibit CLP-MCOS-1, at 18:6-13.

market costs are also allocated based on the Company's annual peak load coincident with the ISO-NE peak demand,[56] which also occurs primarily in the summer.[57] A seasonal rate therefore provides the necessary price signal for system costs and reflects the seasonality of costs associated with meeting peak load on the system. It is also better aligned with cost causation principles because it assigns the costs of future growth-related capacity needs to the season in which peak loads are most likely to occur.

Instead of simply providing a discount on winter usage above a certain kilowatt-hour threshold, my proposed rate achieves revenue neutrality by charging higher summer rates that counterbalance the lower winter rates. Under this approach, the customers who drive summer peak costs pay for them, and customers who add primarily winter load will benefit from the lower winter rates. It would also address the EV cost-shift concern discussed above, because it does not create an unlimited-quantity discounted block, while still benefiting heat pump customers with lower winter rates, since heat pump energy consumption is concentrated in the winter. Because the Company expects to continue being summer-peaking through 2031[58] but projects that heat pump adoption could convert a large portion of its system to winter peaking within one to two decades,[59] the seasonal differential should be revisited in each rate case as load profiles change.

Q Please describe the TOU aspect of your proposed rate.

A The TOU structure encourages load shifting away from peak periods, helping to improve system efficiency in both winter and summer. Because the rate would apply to the

[56] ISO-NE. *Capacity Market Cost Allocation,* at 2. https://www.iso-ne.com/static-assets/documents/100033/a07.1.e_mc_rc_2026_03_10-12_capacity_market_cost_allocation.pdf.
[57] ISO-NE. *New England's Electricity Use.* https://www.iso-ne.com/about/key-stats/electricity-use
[58] Exhibit MCOS-1, at 6:9-12.
[59] *Ibid.* at 10.

customer's whole-house load, customers are incentivized to manage their end-use consumption to minimize their bills, including through technological solutions such as smart thermostats, flexible electric vehicle charging, or behind-the-meter energy storage, as well as through behavior changes. Specifically, I propose a year-round on-peak period of 4pm to 8pm on weekdays. This on-peak designation generally aligns with the hours with the highest system load, probability of peak, distribution marginal costs, and wholesale energy prices, as shown in Figure 1 through Figure 4 below.

Figure 1. Average Hourly System Load, 2023-2025 (MW)[60]

Hour	Month >	1	2	3	4	5	6	7	8	9	10	11	12	Average
0		1975.30	1944.46	1728.99	1555.94	1545.10	1885.26	2320.01	1985.99	1709.25	1527.85	1662.98	1941.48	1815.22
1		1897.42	1872.85	1656.00	1475.39	1445.95	1750.19	2149.43	1846.64	1599.59	1442.16	1635.89	1853.32	1718.74
2		1855.12	1838.11	1618.41	1428.49	1385.03	1661.04	2029.37	1749.76	1528.31	1390.98	1545.79	1807.23	1653.14
3		1845.63	1835.49	1615.31	1417.81	1356.87	1607.73	1952.31	1689.36	1486.81	1370.15	1537.61	1796.59	1625.97
4		1900.25	1900.91	1675.58	1465.99	1385.12	1601.11	1926.66	1678.23	1497.52	1408.78	1593.85	1843.99	1656.50
5		2048.06	2048.42	1820.32	1600.14	1489.46	1674.24	1989.69	1759.89	1603.29	1541.47	1738.11	1982.75	1774.65
6		2259.24	2256.44	2028.47	1771.10	1637.38	1812.55	2119.17	1881.74	1764.40	1747.65	1932.86	2177.99	1949.08
7		2380.28	2338.75	2102.49	1832.23	1704.23	1924.78	2255.77	1990.70	1854.85	1853.77	2004.07	2294.77	2044.72
8		2397.61	2319.58	2076.37	1818.60	1700.78	1987.10	2357.13	2054.62	1880.17	1841.24	1984.20	2310.59	2060.67
9		2373.30	2254.85	2008.12	1771.07	1685.01	2030.72	2452.93	2094.58	1886.06	1801.84	1923.74	2284.04	2047.19
10		2329.89	2199.63	1914.47	1713.47	1670.17	2081.41	2560.84	2152.83	1893.47	1747.48	1866.14	2239.43	2030.77
11		2297.82	2141.78	1839.84	1677.24	1659.02	2146.95	2675.91	2231.02	1920.55	1700.58	1827.82	2201.28	2026.65
12		2274.90	2089.06	1783.93	1638.85	1662.28	2219.05	2792.03	2325.36	1960.75	1674.07	1816.30	2175.88	2034.37
13		2272.60	2066.55	1763.80	1623.06	1685.15	2297.93	2917.54	2428.88	2015.74	1679.92	1838.48	2178.89	2064.05
14		2302.66	2070.13	1753.40	1629.55	1704.15	2357.38	3011.93	2507.74	2078.17	1720.41	1899.62	2231.69	2105.57
15		2393.15	2165.15	1794.79	1663.85	1755.57	2432.78	3107.92	2588.07	2152.66	1786.94	2043.24	2360.22	2187.03
16		2575.00	2380.43	1929.40	1752.01	1859.68	2536.89	3204.35	2687.87	2267.41	1971.97	2238.16	2562.99	2330.51
17		2694.34	2566.06	2140.38	1914.65	1985.18	2624.00	3290.04	2777.13	2393.67	2116.36	2322.22	2630.73	2454.56
18		2691.12	2586.61	2237.03	2025.71	2074.59	2678.31	3316.43	2821.57	2443.11	2175.92	2318.67	2622.10	2499.26
19		2632.41	2546.25	2268.92	2084.83	2111.65	2656.59	3252.50	2769.28	2423.57	2164.98	2265.93	2566.72	2478.64
20		2550.48	2470.33	2234.72	2081.38	2103.52	2584.62	3137.11	2696.62	2363.95	2088.40	2192.41	2498.39	2416.83
21		2438.05	2364.69	2141.04	1997.73	2045.61	2505.23	3022.28	2579.22	2226.46	1974.31	2088.76	2398.44	2315.15
22		2283.60	2222.96	2000.97	1851.17	1889.82	2324.08	2806.16	2384.07	2050.99	1825.78	1947.99	2254.01	2153.47
23		2111.79	2063.29	1840.64	1683.48	1700.40	2098.40	2547.52	2163.94	1858.43	1659.17	1791.04	2081.53	1966.63

[60] OCC-863 Attachment 1.

Figure 2. Weekday Probability of Peak by Month and Hour[61]

Hour	Month > 1	2	3	4	5	6	7	8	9	10	11	12
0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8	0.00%	0.00%	0.00%	0.00%	0.00%	0.07%	0.03%	0.01%	0.00%	0.00%	0.00%	0.00%
9	0.00%	0.00%	0.00%	0.00%	0.00%	0.14%	0.25%	0.09%	0.00%	0.00%	0.00%	0.00%
10	0.00%	0.00%	0.00%	0.00%	0.00%	0.18%	0.58%	0.22%	0.06%	0.00%	0.00%	0.00%
11	0.00%	0.00%	0.00%	0.00%	0.00%	0.25%	1.06%	0.36%	0.11%	0.00%	0.00%	0.00%
12	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	1.65%	0.64%	0.19%	0.00%	0.00%	0.00%
13	0.00%	0.00%	0.00%	0.00%	0.00%	0.48%	2.16%	1.10%	0.32%	0.00%	0.00%	0.00%
14	0.00%	0.00%	0.00%	0.00%	0.00%	0.67%	2.82%	1.45%	0.40%	0.00%	0.00%	0.00%
15	0.00%	0.00%	0.00%	0.00%	0.01%	0.98%	4.30%	1.90%	0.50%	0.00%	0.00%	0.00%
16	0.00%	0.00%	0.00%	0.00%	0.01%	1.53%	5.27%	2.65%	0.61%	0.00%	0.00%	0.00%
17	0.00%	0.00%	0.00%	0.00%	0.02%	1.81%	6.18%	3.01%	0.62%	0.00%	0.00%	0.00%
18	0.00%	0.00%	0.00%	0.00%	0.00%	1.88%	6.30%	2.84%	0.60%	0.00%	0.00%	0.00%
19	0.00%	0.00%	0.00%	0.00%	0.00%	1.41%	5.22%	2.13%	0.44%	0.00%	0.00%	0.00%
20	0.00%	0.00%	0.00%	0.00%	0.00%	0.94%	3.43%	1.34%	0.33%	0.00%	0.00%	0.00%
21	0.00%	0.00%	0.00%	0.00%	0.00%	0.49%	2.26%	0.68%	0.15%	0.00%	0.00%	0.00%
22	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	0.68%	0.14%	0.02%	0.00%	0.00%	0.00%
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.06%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 3. Average Hourly Marginal Costs by Month ($/kWh)[62]

No Days in month	29	28	33	30	30	31	30	32	30	29	32	31
Hour \ Month >	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
7	0.00000	0.00000	0.00000	0.00000	0.00000	0.00009	0.00004	0.00001	0.00000	0.00000	0.00000	0.00000
8	0.00000	0.00000	0.00000	0.00000	0.00000	0.00045	0.00038	0.00014	0.00000	0.00000	0.00000	0.00000
9	0.00000	0.00000	0.00000	0.00000	0.00000	0.00102	0.00269	0.00079	0.00004	0.00000	0.00000	0.00000
10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00126	0.00533	0.00211	0.00062	0.00000	0.00000	0.00000
11	0.00000	0.00000	0.00000	0.00000	0.00000	0.00200	0.00977	0.00381	0.00112	0.00000	0.00000	0.00000
12	0.00000	0.00000	0.00000	0.00000	0.00000	0.00258	0.01452	0.00653	0.00193	0.00000	0.00000	0.00000
13	0.00000	0.00000	0.00000	0.00000	0.00000	0.00396	0.01923	0.01068	0.00292	0.00000	0.00000	0.00000
14	0.00000	0.00000	0.00000	0.00000	0.00003	0.00546	0.02442	0.01467	0.00358	0.00000	0.00000	0.00000
15	0.00000	0.00000	0.00000	0.00000	0.00005	0.00785	0.03688	0.01819	0.00456	0.00000	0.00000	0.00000
16	0.00000	0.00000	0.00000	0.00000	0.00013	0.01254	0.04764	0.02451	0.00572	0.00000	0.00000	0.00000
17	0.00000	0.00000	0.00000	0.00000	0.00018	0.01546	0.05736	0.02798	0.00574	0.00000	0.00000	0.00000
18	0.00000	0.00000	0.00000	0.00000	0.00003	0.01689	0.05874	0.02609	0.00549	0.00000	0.00000	0.00000
19	0.00000	0.00000	0.00000	0.00000	0.00000	0.01205	0.04722	0.01968	0.00393	0.00000	0.00000	0.00000
20	0.00000	0.00000	0.00000	0.00000	0.00000	0.00804	0.03099	0.01231	0.00286	0.00000	0.00000	0.00000
21	0.00000	0.00000	0.00000	0.00000	0.00000	0.00420	0.02034	0.00625	0.00128	0.00000	0.00000	0.00000
22	0.00000	0.00000	0.00000	0.00000	0.00000	0.00102	0.00602	0.00123	0.00011	0.00000	0.00000	0.00000
23	0.00000	0.00000	0.00000	0.00000	0.00000	0.00007	0.00055	0.00000	0.00000	0.00000	0.00000	0.00000

[61] OCC-863 Attachment 2, at 3.
[62] OCC-863 Attachment 2, at 1.

Figure 4. Average Day-Ahead Hourly Locational Marginal Prices by Month, 2025 ($/MWh)[63]

Hour	Month >	1	2	3	4	5	6	7	8	9	10	11	12	Average
0		121.68	117.57	41.68	36.85	31.12	34.44	51.21	37.30	29.85	34.68	47.61	113.33	58.11
1		116.18	115.11	41.11	34.91	28.85	32.40	45.83	34.16	28.40	32.67	48.70	120.15	56.54
2		112.65	113.19	39.90	32.94	27.66	30.00	42.84	31.60	26.21	31.41	46.26	119.41	54.51
3		109.03	110.17	38.67	32.36	26.71	28.25	40.68	30.22	25.63	30.51	44.38	113.95	52.55
4		109.64	110.20	40.06	33.71	27.51	28.76	40.37	30.34	25.92	31.55	44.42	113.20	52.97
5		113.84	114.09	43.62	37.34	30.65	30.35	43.16	32.27	28.26	34.18	46.66	116.35	55.90
6		121.92	123.30	54.59	48.80	33.81	32.56	47.61	34.54	34.16	44.74	50.57	123.53	62.51
7		138.49	136.12	61.31	50.76	36.71	35.64	48.97	38.42	36.56	51.83	66.18	129.70	69.22
8		159.31	152.13	54.30	43.88	33.80	33.97	48.79	37.28	31.92	44.26	72.21	146.01	71.49
9		145.48	139.38	45.37	39.77	32.95	33.74	49.42	35.05	27.80	37.32	60.04	137.91	65.35
10		131.40	127.88	42.55	38.04	33.50	33.81	51.41	35.40	27.76	34.33	54.42	127.11	61.47
11		126.19	123.49	40.97	36.09	31.99	35.26	56.73	37.02	27.81	32.64	51.93	125.27	60.45
12		118.57	118.59	37.85	34.26	31.56	38.63	61.57	39.83	28.26	32.10	50.26	121.21	59.39
13		115.10	113.68	37.38	33.88	31.88	44.03	70.46	44.74	30.17	32.19	52.05	116.97	60.21
14		115.93	111.90	36.02	33.23	30.98	44.62	77.31	49.91	31.37	32.84	54.58	115.37	61.17
15		121.26	115.91	37.33	34.55	32.26	51.89	87.13	52.18	32.99	35.06	57.51	118.23	64.69
16		131.56	122.17	40.63	37.27	36.43	58.89	103.37	60.66	39.37	46.10	62.11	130.21	72.40
17		146.13	131.98	47.34	43.40	41.50	68.63	136.07	71.98	48.88	60.33	75.23	152.84	85.36
18		173.60	158.72	56.02	50.73	46.02	74.01	141.70	78.51	51.73	65.14	85.61	164.93	95.56
19		161.36	157.40	63.27	56.17	49.48	70.83	120.17	66.43	49.46	53.95	74.82	153.44	89.73
20		148.04	145.07	57.50	55.19	50.18	64.31	99.29	61.27	43.79	48.36	68.33	143.66	82.08
21		138.90	135.52	50.16	48.48	43.41	53.04	81.15	53.99	37.80	40.54	65.04	142.30	74.19
22		129.91	124.51	44.74	42.02	37.23	39.11	62.08	43.12	32.79	35.69	55.93	131.11	64.85
23		122.88	117.01	39.72	36.16	31.37	33.70	52.62	37.77	29.66	33.42	50.27	120.89	58.79

Q Why do you propose time-differentiating supply and transmission costs as well as distribution costs?

A Time-differentiating all rate components would provide more meaningful price signals and better reflect cost causation. Customers respond to the price signals presented by the total rates, rather than to any specific rate component. Since distribution only represents a portion of customers' bills, the price signal provided by time-differentiated distribution rates will be diluted if transmission and supply charges continue to be flat. Additionally, distribution, transmission, and supply costs are all disproportionately driven by peak demand. Following cost causation principles, therefore, requires that all rate components be differentiated.

[63] Calculated using ISO-NE 2025 SMD Hourly Data for Connecticut. https://www.iso-ne.com/static-assets/documents/100020/2025_smd_hourly.xlsx

Q Please explain your process to develop the distribution portion of your proposed electrification rate.

A The distribution portion of my proposed rate design is based on marginal costs. Similar to the Company's proposed Rate 6, I began with a customer charge reflecting the Company's estimated marginal customer cost, at $30.95, which reduces the revenue requirement that must be recovered through volumetric charges compared to Rate 1. To calculate the volumetric charges, I first calculated the average marginal distribution cost for each TOU period (summer on-peak, summer off-peak, winter on-peak, and winter off-peak) using the average hourly marginal cost data provided by the Company.[64] I then scaled the marginal prices for each TOU period up by an equal percentage to arrive at rates sufficient to recover the Rate 1 distribution revenue requirement. Because marginal distribution costs are concentrated almost entirely in the summer, prices are significantly higher in summer months than in winter months.

Q Please explain your process to develop the transmission portion of your proposed electrification rate.

A I designed the transmission rates by allocating 25 percent of the transmission revenue requirement to on-peak hours and 75 percent of the transmission revenue requirement to all hours. This approach represents a balance between reflecting the ISO-NE transmission cost allocation methodology, which allocates transmission costs based on monthly coincident peak demand (12CP), and maintaining reasonable on-peak to off-peak price differentials, since allocating transmission costs only to on-peak hours would result in exceptionally high on-peak prices. My proposed approach also reflects cost causation:

[64] OCC Attachment 2, at 1.

some transmission costs are caused by the need to connect generation resources to load centers as well as reliability improvements, and these costs are better recovered from usage across all hours rather than from only usage during peak hours.

Q Please explain your process to develop the supply portion of your proposed electrification rate.

A To design the generation rates, I first calculated the portion of the supply revenue requirement that accounts for capacity costs and the portion that accounts for energy and ancillary services based on 2025 ISO-NE data.[65] The capacity costs are allocated entirely to usage during the summer on-peak period, reflecting that the Company's capacity cost responsibility is largely driven by summer peak demand. Energy and ancillary services costs are allocated based on an analysis of total energy costs (price times load) in each TOU period, using 2025 hourly day-ahead Locational Marginal Prices[66] and the Rate 1 hourly load profile.[67] I then scaled the resulting costs for each TOU period up to match the non-capacity portion of the supply revenue requirement.

Q What is your proposed TOU rate?

A The rate resulting from the methodology described above is provided in Table 5. The rate includes higher summer rates and lower winter rates, with a total summer on-peak to off-peak price ratio of 4.3:1 and a winter on-peak to off-peak price ratio of 1.7:1.

[65] ISO-NE. 2026. *2025 Annual Markets Report*, Figure 1-1. https://www.iso-ne.com/static-assets/documents/100035/2025-annual-markets-report.pdf
[66] ISO-NE 2025 SMD Hourly Data for Connecticut. https://www.iso-ne.com/static-assets/documents/100020/2025_smd_hourly.xlsx
[67] OCC-863 Attachment 4.

Table 5. Proposed Seasonal TOU Electrification Rate

	Distribution	Transmission	Supply	Total
Customer Charge ($/month)	$30.95			$30.95
Energy Charges ($/kWh)				
Summer on-peak	$0.658974	$0.121434	$0.388237	$1.168646
Summer off-peak	$0.157286	$0.036675	$0.076061	$0.270022
Winter on-peak	$0.000308	$0.121434	$0.152059	$0.273802
Winter off-peak	$0.000034	$0.036675	$0.125959	$0.162668
Price ratios				
Summer on- to off-peak				4.3:1
Winter on- to off-peak				1.7:1

Q Can a two-season, two-period rate be implemented without significant complexity?

A Yes. The Company already has the capability to implement TOU rates, as shown by Rate 7, and seasonal rates, as shown by its own Rate 6 proposal.

Q Is OCC proposing this rate to be considered as potential fulfillment of the time-varying rate design and submission requirements required by Public Act 25-173?

A No. Given the higher differentials in this proposed seasonal TOU rate, it should be offered as an opt-in rate, and the Authority should also consider implications of this rate for customers with a financial hardship designation. If any aspect of my proposed rate is eventually proposed as a rate designed to comply with Public Act 25-173 Section 20's requirement for the EDCs to propose an opt-out time varying rate, it should incorporate principles required by the Act, including "consideration for principles of gradualism and customer acceptance and established exceptions as deemed appropriate by the authority, including, but not limited to, for medically protected and financial hardship customers."[68]

[68] Codified as Conn. Gen. Stat. Ann. § 16-243n

VI. ECONOMIC DEVELOPMENT RATE PROPOSAL

Q Please summarize Eversource's proposed Economic Development Rate.

A Eversource proposes an EDR rider that would establish discounted rates for incremental load growth of at least 1 MW from new and existing large commercial and industrial (Rate 57 and Rate 58) customers.[69] The EDR is structured as a percentage discount that applies to the customer's incremental distribution demand and energy charges and that declines over a 5-year term, with the specific discount level determined through direct negotiation with the customer.[70] Additionally, the discount is anchored to the customer's marginal cost of service and subject to a cap tied to the incremental distribution revenues from the new load, and the customer is still responsible for interconnection, system upgrade, and make-ready costs.[71]

Q Do you have concerns with the Company's proposed EDR?

A Yes. While a well-designed EDR with strong safeguards around ratepayer impacts can help incentivize incremental load that helps both support economic development and system utilization, I have three concerns with the Company's proposal. First, the proposal lacks sufficient detail on safeguards against the potential impacts of hyperscale data center load. Second, the rate does not sufficiently encourage customers on the EDR to utilize the system in an efficient manner. Third, the Company's proposed approach to determining the discount level would add administrative complexity and regulatory burden, and it is not transparent. For these reasons, I recommend that the Authority reject Eversource's proposed EDR and instead approve a modified EDR that I describe below.

[69] Exh. CLP-RATES-1, at 24:19-25:1.
[70] Exh. CLP-RATES-1, at 28:3-22; Eversource Response to OCC-458.
[71] Exh. CLP-RATES-1, at 28:5-7, 29:4-9.

A. The EDR proposal lacks sufficient safeguards against the potential ratepayer impacts of hyperscale data center load

Q What are the potential ratepayer impacts of hyperscale data center load?

A Utilities around the country are receiving an unprecedented amount of load requests from the data center industry.[72] Unlike traditional industrial loads, which mainly represent manufacturing sectors, these new large loads from data centers, which are driven by demand for artificial intelligence computing, are larger in size and have higher load factors. These characteristics present unique challenges to utility system operations and planning, with potential for significant adverse impacts on other utility customers. The magnitude of the load required by data centers at each site often requires new system investments, including for generation, transmission, and distribution capacity, which can increase costs for the system and for existing ratepayers. Additionally, data center developers also submit many load requests to different utilities without planning to develop projects in all utility service territories, making these large loads difficult to forecast and plan for.[73] If a utility makes system investments to accommodate an anticipated large load that ultimately does not materialize, existing customers will be saddled with the costs of those investments. Recognizing these risks, many states across the country have adopted or are in the process of adopting large load tariffs to manage the costs associated with such loads and protect existing ratepayers from potential cost

[72] Goldman Sachs. 2026. *US Data Center Power Demand Projected to Double by 2027.* https://www.goldmansachs.com/insights/articles/us-data-center-power-demand-projected-to-double-by-2027

[73] Energy Systems Integration Group (ESIG). 2026. *Historical and Modern Large Loads: Characteristics, Context, and Industry Actions to Meet grid and Customer Needs*. https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Historical-vs-Modern-Large-Loads-white-paper-2026.pdf

shifts.[74] Given that the primary objective of the EDR rider is to improve affordability, extending the discount to data center loads would be counter to the stated objective.[75]

Q Would providing the EDR to hyperscale data center loads induce incremental load that otherwise would not materialize?

A No. In contrast to traditional manufacturing industries, which operate with lower profit margins and therefore are more sensitive to electricity prices, recent data center developments tend to prioritize "speed to power" over cost.[76] This means that the availability of a rate discount is unlikely to drive investment decisions. Thus, making the EDR available to this customer type would not induce incremental load that otherwise would not be added.

Q Does Eversource propose to allow data center loads to participate in the EDR?

A The Company explains that data center customers are "not categorically excluded… nor are they categorically eligible;" instead, any customers interested in the EDR must meet the rider's eligibility requirements.[77] Additionally, the Company states that data center loads "raise broader policy questions" and that it will work with the state on potential data center-specific rates if there are future load requests from these large computational loads.[78]

Q What do you recommend?

A I recommend that the Authority adopt an explicit exclusion of data center loads from EDR participation. I also recommend that the Authority open a separate generic

[74] Smart Electric Power Alliance. *DELTa: Database of Emerging Large-Load Tariffs.* https://sepapower.org/large-load-tariffs-database/
[75] Eversource Response to OCC-457.
[76] Center for Strategic & International Studies. 2025. *The Electricity Supply Bottleneck on U.S. AI Dominance.* https://www.csis.org/analysis/electricity-supply-bottleneck-us-ai-dominance
[77] Eversource Response to OCC-464.
[78] Ibid.

proceeding to determine what customer protections should be included in any future data center tariffs.

B. The lack of meaningful time-varying rates for EDR customers will reduce the ability of incremental load to support more efficient system utilization

Q Why is it important for EDR customers to receive price signals that encourage load flexibility?

A New load being added to the system can only improve system efficiency if the revenues the utility receives from that new load are greater than its marginal cost to serve. This depends on the customer's load shape: new load added primarily to peak hours may necessitate new investments in distribution capacity to accommodate higher peak loads as well as increase the utility's cost responsibility for transmission and generation. While the Company proposes to ensure that revenues collected from the customer are greater than their marginal cost to serve, this determination is only based on the Company's marginal distribution cost of service study, which does not account for impacts on transmission and supply costs.[79] These costs impact all ratepayers and could diminish the benefits from the increased sales. On the other hand, the benefits of new load to the system and existing ratepayers are maximized when that new load is added primarily to off-peak hours, when the grid can absorb additional load with existing system capacity and when wholesale market prices are low. Therefore, to ensure that new EDR load can improve system efficiency, EDR customers should receive price signals that encourage off-peak usage and discourage on-peak usage. Time-varying rates can provide these price signals.

[79] Eversource Response to OCC-459.

Q Do the rates under which EDR customers take service provide time-varying price signals?

A Yes, but the price signals are weak. The Company proposes that the EDR rider would be available to customers taking service under Rate 57 (Large Time-of-Day – Manufacturers) and Rate 58 (Large Time-of-Day – Non-Manufacturers).[80] Despite both tariffs having "Time-of-Day" in their names, the only time-differentiated rate component is the transmission demand charge, which only applies to customer demand during on-peak hours, while distribution and generation charges are not differentiated or only minimally differentiated between on-peak and off-peak hours.[81] Additionally, the on-peak period is eight hours long, which can make it difficult for customers to manage around and does not precisely target the hours when system costs are the highest (as discussed in Section V.29C above). Under these rate structures, customers do not receive meaningful and actionable price signals to shift load from on-peak hours to off-peak hours.

Q What do you recommend?

A I recommend that the Authority require the Company to file TOU rates for industrial customers within six months of the Authority's decision in this proceeding and require EDR customers to take service under those rates. The TOU rates should include time-differentiated distribution, transmission, and generation charges, and should include a shorter on-peak period.

[80] Exh. CLP-RATES-1, at 24:20-25:1.
[81] Rate 57, https://www.eversource.com/docs/default-source/rates-tariffs/ct-electric/rate-57-ct.pdf?sfvrsn=ecf85333_29; Rate 58, https://www.eversource.com/docs/default-source/rates-tariffs/ct-electric/rate-58-ct.pdf?sfvrsn=9135fd38_29

C. Determining the EDR via negotiations with individual customers would add administrative complexity and would not be transparent

Q What factors influence the discount level negotiated with each EDR customer?

A Eversource explains that the base discount schedule the Company will use to initiate negotiations is a 25 percent discount in year 1, with 5 percent decrements in each of the 4 subsequent years and terminating after 5 years.[82] From this starting point, the discounts and the term could be adjusted as part of the negotiations, taking into account the economic value and contribution to fixed costs provided by each customer while still ensuring revenue sufficiency.[83]

Q What are your concerns with the proposed approach to determine the discount level?

A The Company's proposed approach is administratively burdensome and not transparent. There are no clear guidelines on how different amounts of economic and/or ratepayer benefits would correspond to different discount levels, meaning that the negotiations can result in different discount levels and varying levels of ratepayer benefits for similar EDR customers. Allowing the Company to provide the customer with whatever discount level agreed upon between the two parties would mean forgoing sufficient regulatory review of whether the negotiated discount level is optimal from existing ratepayers' perspective. On the other hand, requiring the Authority to review each negotiated discount schedule with individual EDR customers could place additional administrative burden on the Authority, the Company, EDR applicants, OCC, and other stakeholders. This additional regulatory review would also stretch out the timeline between when a customer submits their EDR

[82] Eversource Response to OCC-933.
[83] Eversource Responses to OCC-929, 930, 932, and 933.

application and when they are enrolled in the EDR, delaying the potential economic and ratepayer benefits of the EDR.

Q What do you recommend?

A I recommend that the Authority reject Eversource's proposal to determine the EDR discount schedule via direct negotiations with each customer. Instead, the Authority should adopt an EDR that mirrors the one approved for UI in Docket No. 22-08-08. In that docket, the Authority approved fixed discount levels for UI's EDR rider, including a 15 percent base discount and a 20 percent discount for customers located in Distressed Municipalities and Environmental Justice Communities. Rather than approve a discount that declined each year, the Authority found that "a fixed rate discount over the term of the EDR Rider is the least-cost method of administering the EDR Rider" and that "the EDR Rider should broadly promote economic development in underserved locations."[84] The Authority also adopted a total discount cap of 50 percent of the total incremental distribution revenue from the incremental load to ensure that existing ratepayers receive at least 50 percent of the benefits from the incremental load.[85]

I recommend that the Authority approve a similar EDR for Eversource. This EDR would have fixed discount levels (i.e., not declining over time), divided into two tiers:

[84] CT PURA Decision, p. 249-251. August 25, 2023. Docket No. 22-08-08.
[85] Ibid.

1) a 20 percent discount level for facilities sited in an Environmental Justice Community, as designated by the Department of Energy & Environmental Protection,[86] and

2) a 15 percent discount level for facilities sited in other communities.

The higher Tier 1 discount will help incentivize investments in economically distressed communities, where the economic benefits (including jobs) of new load are most impactful. Other limitations on the discount level proposed by Eversource should still apply, including a discount period of 5 years as well as a cap based on the customer's marginal cost to serve and incremental distribution revenues. Specifically, the Authority should adopt a discount cap equal to 50 percent of the net present value of the incremental distribution revenues, accounting for the cost of connecting the customer and any other electric infrastructure investments made to serve the incremental load.

Q Why is your recommended approach superior to Eversource's proposal?

A Adopting fixed discount rates for all EDR customers would reduce the costs and administrative burden by eliminating the need for potentially complex negotiations and lengthy regulatory review for each rate discount, while still ensuring that EDR customers provide benefits to existing ratepayers. It would also be simpler to understand than a declining discount and provide greater transparency and certainty for customers

[86] Connecticut Department of Energy & Environmental Protection. *Learn More About Environmental Justice Communities.* https://portal.ct.gov/deep/environmental-justice/05-learn-more-about-environmental-justice-communities.
An Environmental Justice Community is 1) a distressed municipality, or 2) a census block group where 30% of the population is living below 200% of the federal poverty level.

considering locating in Eversource's territory. Finally, it would promote fairness by ensuring that similar customers receive similar discounts.

VII. CONCLUSION

Q Please summarize your conclusions.

A I recommend that the Authority:

- Reject the Company's minimum system method and direct the Company to classify distribution costs using the basic customer method in which only meters, services, meter reading, and billing costs are classified as customer-related, until more granular analysis can be performed to capture customer density.
- Direct the Company to develop a customer density approach to classification, similar to the one approved by the Ontario Energy Board. Customer-related percentages would vary by density category (urban, mixed, and rural), measured in customers per circuit mile. This analysis should be submitted with its next rate case application.
- If the Authority approves the minimum system method, it should direct the Company to reduce each class's non-coincident peak demand by the load-carrying capability of the minimum system. This is consistent with the Authority's determination in Docket No. 24-10-04 and avoids charging the residential class twice for the same capacity.
- Direct the Company to classify AMI meter costs as 38 percent customer-related, 47 percent demand-related, and 15 percent energy-related, rather than 100 percent customer-related. This classification is based on the present value of AMI benefits quantified in the Company's own benefit-cost analysis, excluding Carbon Reduction and System Costs Avoidance.

- Direct the Company to develop distribution allocators based on AMI data for its next base rate case. Specifically, the Company should retain hourly AMI interval data in a form that can be aggregated by substation, feeder, and line transformer; and file an equipment-level allocation study alongside its conventional cost of service study. The study would allocate substations on class contributions to substation peaks, primary lines on class contributions to feeder peaks, and line transformers on class contributions to transformer peaks.

With respect to the Company's rate design proposals, I recommend that the Authority:

- Reject the Company's proposed Rate 6 and instead adopt a cost-based, seasonal opt-in TOU rate that includes time-differentiated distribution, transmission, and supply charges.
- Reject the Company's proposed EDR rider and instead adopt one based on UI's EDR with additional modifications. Specifically, the EDR should:
    - Exclude data center loads from qualifying for the rate;
    - Require EDR customers to take service on an enhanced TOU rate, to be filed by Eversource within six months of the Authority's decision in this proceeding;
    - Adopt fixed discount levels, including a 20 percent discount for facilities sited in an Environmental Justice Community and a 15 percent discount for facilities sited in other communities, with a discount cap of 50 percent of the net present value of incremental revenues.

Q Does this conclude your testimony?

A Yes, it does.