Date Filed: November 12, 2026

Witness: Jared A. Lawrence, Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the AMI Panel Testimony at page 15, lines 12-21.

a. Please provide the number of meters the Company expects to replace with AMI meters, by rate class (including Rate 39, Rate 57 and Rate 58).
b. Please provide the number of Rate 39, Rate 57 and Rate 58 customers whose existing meters record interval demand or energy data, and identify the type of meter installed for those customers.
c. Please state whether the meters of Rate 39, Rate 57 and Rate 58 customers that already record interval data will be replaced with AMI meters under the AMI Implementation Plan. If so, explain why replacement is necessary for those customers.
d. Please provide the average installed cost per meter, by rate class, of (i) the existing meters and (ii) the AMI meters the Company plans to install.

Response:

a. The table below presents the Company's best estimate of the number of meters that will be eligible for replacement with an AMI meter, disaggregated by rate class. These numbers are expected to change slightly based on population growth and technical limitations that prevent AMI meters for certain customer configurations that are not easily discernable from the rate class alone (such as the use of KYZ pulses or the need for real-time data).

Rate	Count
01	1,089,364
05	137,777
07	842
11	315
12	381
18	173
19	3
27	524
29	232
30	109,281
35	1,276

37	1,772
39	1
40	1,739
41	13
55	330
56	877
57	74
58	67
70	70
71	37
72	38
73	4
87	22,724

b. The table below lists the counts and various meter types on Rate 39, 57, and 58 that record interval data. There is some overlap between the meters on the table below and meters listed on the first table above because some interval meters will be eligible to move to AMI.

Rate	Meter Type	Count
39	A3 Meter	1
39	ION Meter	2
57	A3 Meter	71
57	ION Meter	4
57	KV2C Meter	1
58	A3 Meter	65
58	ION Meter	2
58	KV2C Meter	1

c. The Company will pursue installing AMI meters wherever possible for the Company and the customer to realize the benefits of AMI. With that said, these rates represent some of the largest electric delivery points that commonly include additional metering complexities such as totalization, KYZ pulses, real time data, or other contractual obligations. At a later date, the Company will evaluate all complex metering customers on a case-by-case basis to determine if AMI meters can meet the specific needs of each site/customer.

d. Please refer to CIEC-038 Attachment 1, CONFIDENTIAL, for the requested pricing information.

Date Filed: November 16, 2026

Witness: Jared A. Lawrence, Douglas P. Horton, Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the AMI Panel Testimony at page 19, lines 1-6, and Exhibit CLP-AMI-3 at pages 16-17 (Figure 6).

a. Figure 6 shows $309.2 million of six-year capital for "Meters," consisting of $302.4 million for Meters and $6.8 million of Undepreciated Meter Balance. Please separate the $302.4 million into (i) meter equipment and (ii) meter installation labor and other costs, and identify the amount the Company expects to record in FERC Account 370.

b. For each cost category shown in Figure 6, please identify the FERC account or accounts in which the Company expects to record the capital investment.

c. Please identify the VVO Enablement facilities (e.g., substation and line equipment, software) included in the $97.3 million of six-year VVO Enablement capital shown in Figure 6, and state whether the Company proposes to recover those costs through the PBMRP as AMI costs or through another mechanism, and how it proposes to classify and allocate those costs to rate classes.

Response:

a. A full breakdown of the six-year capital for meters is shown in the table below[1]. Please refer to CLP-AMI-3 starting on page 108 for a complete breakdown of all capital.

6-Year Meters – Nominal Capital Cost	
Meters - Deployment	$208.8M
External Labor – Deployment	$51.8M
Internal Labor – Deployment Returns/Follow-ups	$7.0M
Meters – Replacements	$2.8M
Internal Labor - Replacements	$1.1M
Corporate Overhead	$3.8M
Contingency	$27.1M
Total	**$302.4M**

[1] Note: these are rounded figures.

The Company expects to record the full cost of the meter equipment, the cost to install, and all associated costs, including overhead costs and allocations, to FERC Utility Account 370 - Meters. Please see Table 1 below.

b. For each cost category shown in Figure 6, please see Table 1 below, which provides the Plant FERC Utility Account in which the Company expects to record the capital investment, once it is placed in service and unitized (final as built) to FERC Account 101010 (Electric Plant in Service).

Cost Category	Capital Investment / O&M Expense	Plant FERC Utility Account
Meters	Meters	370 – Meters & Metering Equipment
Communications	Communications Upgrades	370 – Meters & Metering Equipment
Back Office Systems	Meter Data Management System (MDMS)	363.1 – Computer Hardware; 363.2 - Computer Software
	Customer Information System (CIS)	363.1 – Computer Hardware; 363.2 - Computer Software
	Load Settlement	363.1 – Computer Hardware; 363.2 - Computer Software
Labor and Standard Operating Plan	Organizational Readiness	363.1 – Computer Hardware; 363.2 - Computer Software
	Contact Center	363.1 – Computer Hardware; 363.2 - Computer Software
	Revenue Assurance (Non-Technical Line Loss)	363.1 – Computer Hardware; 363.2 - Computer Software
Supporting Services and Platforms	OMS Integration	363.1 – Computer Hardware; 363.2 - Computer Software
	Customer Experience Portal	363.1 – Computer Hardware; 363.2 - Computer Software
	Engineering and Customer Usage Analytics	363.1 – Computer Hardware; 363.2 - Computer Software
	Green Button Connect	363.1 – Computer Hardware; 363.2 - Computer Software
VVO Enablement	VVO Enablement	363.1 – Computer Hardware; 363.2 - Computer Software; 363.3 - Communication Equipment 368 - Line Transformers 362 - Station Equipment
Customer	Customer Engagement	N/A
Data	Cybersecurity	363.1 – Computer Hardware; 363.2 - Computer Software
	Data Storage and Processing	N/A

c. A listing of the VVO Enablement facilities is shown in the table below. As described in the Company's response to CIEC-040[i], the Company expects that AMI meter costs will be properly classified as customer-related costs, consistent with treatment of meter costs in the allocated cost-of-service study conducted and submitted in this docket as part of the Company's Rate Application. The Company's further expectation is that capital costs and expenses associated with AMI implementation would be collected from customers

consistent with allocation of costs and rate design allowed in this proceeding for distribution rates or another applicable rate mechanism.

6-Year VVO Enablement – Nominal Capital Cost	
Regulators	$37.5M
Capacitors	$27.3M
Transformer LTC Controller Upgrades	$16.0M
Integration - Software	$0.5M
Integration – External Labor	$1.0M
Integration – Internal Labor	$0.5M
Corporate Overhead	$0.5M
Contingency	$8.3M
AFUDC	$5.7M
Total	**$97.3M**

Prior Referenced Responses:

[i] CIEC-040 Question:

Please refer to the AMI Panel Testimony at page 20, lines 9-21.

a. Please confirm that, as stated at lines 9-11, the Company must be able to accurately and timely bill customers for service, and metering infrastructure is necessary to that end.
b. Please confirm that, as stated at lines 12-15, the Company expects to migrate to AMI as its existing AMR meters reach the end of their useful lives, regardless of the BCA results.
c. Please explain the statement at lines 18-20, that "optionality in taking advantage of many AMI benefits will be within the customer's control," and identify the AMI benefits in Exhibit CLP-AMI-3, to which that statement applies.
d. When AMI meter costs are reflected in base distribution rates, does the Company intend to continue classifying AMI meter costs as customer-related, consistent with its treatment of meter costs in the ACOS Direct Testimony at page 4, lines 5-7? If not, explain why not.

CIEC-040 Response:

a. Yes, the Company must always be in a position to bill customers for service on a timely and accurate basis and metering infrastructure is necessary to that end. However, the manner in which the Company achieves this objective can take several forms.
b. Based on the information available to the Company today, and the expectation that PURA and stakeholders' consideration of the AMI Implementation Plan would benefit from a comparison with an AMR lifecycle alternative approach, the Company presented an analysis of a hypothetical AMR end-of-life scenario in its BCA. Should PURA not grant approval of the Company's proposed AMI Plan, the Company would develop and consider alternative scenarios using the best information at that time, including an AMR end-of-life approach, in view of any additional guidance PURA provides in its order.
c. The quantified AMI benefits largely within customer control are associated with their choice of participation in Time-of-use/Time-varying Rates. The non-quantified benefits largely within customer control arise in

relation to their election to receive outage restoration notifications; their receptiveness to detailed billing data and notifications; and their receptiveness to load disaggregation insights.

d. Yes, the Company expects that AMI meter costs will be properly classified as customer-related costs, consistent with treatment of meter costs in the allocated cost-of-service study conducted and submitted in this docket as part of the Company's Rate Application. The Company's further expectation is that capital costs and expenses associated with AMI implementation would be collected from customers consistent with allocation of costs allowed in this proceeding for distribution rates or another applicable rate mechanism.

Date Filed: November 13, 2026

Witness: Jared A. Lawrence, Douglas P. Horton, Edward A. Davis, Kimberly R. Parsons and Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the AMI Panel Testimony at page 20, lines 9-21.

a. Please confirm that, as stated at lines 9-11, the Company must be able to accurately and timely bill customers for service, and metering infrastructure is necessary to that end.

b. Please confirm that, as stated at lines 12-15, the Company expects to migrate to AMI as its existing AMR meters reach the end of their useful lives, regardless of the BCA results.

c. Please explain the statement at lines 18-20, that "optionality in taking advantage of many AMI benefits will be within the customer's control," and identify the AMI benefits in Exhibit CLP-AMI-3, to which that statement applies.

d. When AMI meter costs are reflected in base distribution rates, does the Company intend to continue classifying AMI meter costs as customer-related, consistent with its treatment of meter costs in the ACOS Direct Testimony at page 4, lines 5-7? If not, explain why not.

Response:

a. Yes, the Company must always be in a position to bill customers for service on a timely and accurate basis and metering infrastructure is necessary to that end. However, the manner in which the Company achieves this objective can take several forms.

b. Based on the information available to the Company today, and the expectation that PURA and stakeholders' consideration of the AMI Implementation Plan would benefit from a comparison with an AMR lifecycle alternative approach, the Company presented an analysis of a hypothetical AMR end-of-life scenario in its BCA. Should PURA not grant approval of the Company's proposed AMI Plan, the Company would develop and consider alternative scenarios using the best information at that time, including an AMR end-of-life approach, in view of any additional guidance PURA provides in its order.

c. The quantified AMI benefits largely within customer control are associated with their choice of participation in Time-of-use/Time-varying Rates. The non-quantified benefits largely within customer control arise in relation to their election to receive outage

restoration notifications; their receptiveness to detailed billing data and notifications; and their receptiveness to load disaggregation insights.

d. Yes, the Company expects that AMI meter costs will be properly classified as customer-related costs, consistent with treatment of meter costs in the allocated cost-of-service study conducted and submitted in this docket as part of the Company's Rate Application. The Company's further expectation is that capital costs and expenses associated with AMI implementation would be collected from customers consistent with allocation of costs allowed in this proceeding for distribution rates or another applicable rate mechanism.

Date Filed: November 16, 2026

Witness: Jared A. Lawrence, Douglas P. Horton, Edward A. Davis, Kimberly R. Parsons and Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to Exhibit CLP-AMI-3 at pages 17-18 (Figure 7) and pages 65-67.

a. Please separate the $162.4 million NPV "Improved Restoration – Significant Storms" benefit into (i) avoided Company storm restoration expense and (ii) the value of reduced customer outage time estimated with the interruption cost estimate calculator.

b. For the benefit quantified in part (a)(i), please explain how storm restoration costs are classified and allocated to rate classes in the Company's ACOSS or recovered through the Company's storm cost recovery mechanisms.

c. Please state whether the Company has quantified any of the benefits in Figure 7 by rate class. If so, provide the quantification, including for Rate 39, Rate 57 and Rate 58.

d. Please identify any benefit in Figure 7 that the Company expects to be realized by Rate 39, Rate 57 or Rate 58 customers, and explain the basis for that expectation.

Response:

a) Out of the $162.4M NPV, an estimated $157.20M NPV is associated with avoided storm-restoration expenses and an estimated $5.18M NPV is associated with reduced customer outage time. This is broken down as Business-As-Usual Costs, Benefit Targets and Annual Benefit Calculation. Please refer to CLP-AMI-3, page 69, subsection (c) to see a breakdown of calculations - also shown below.

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Significant Storm Restoration Expense Costs	Baseline Significant Storm Customer Outage Costs	Baseline Total	Significant Storm Avoided Costs from Improved Restoration	Significant Storm Customer Outage Savings from Improved Restoration	Benefit Total
Year 1	$215.79	$42.58	$258.37	$0.00	$0.00	$0.00
Year 2	$220.11	$44.08	$264.19	$0.00	$0.00	$0.00
Year 3	$224.51	$45.64	$270.15	$2.95	$0.10	$3.04
Year 4	$229.00	$47.25	$276.25	$9.01	$0.30	$9.31
Year 5	$233.58	$48.92	$282.50	$15.32	$0.50	$15.83
Year 6	$238.25	$50.64	$288.89	$18.76	$0.62	$19.37
Year 7	$243.02	$52.43	$295.45	$19.13	$0.63	$19.76
Year 8	$247.88	$54.28	$302.16	$19.51	$0.64	$20.16
Year 9	$252.83	$56.20	$309.03	$19.90	$0.66	$20.56
Year 10	$257.89	$58.18	$316.07	$20.30	$0.67	$20.97
Year 11	$263.05	$60.24	$323.28	$20.71	$0.68	$21.39
Year 12	$268.31	$62.36	$330.67	$21.12	$0.70	$21.82
Year 13	$273.67	$64.56	$338.24	$21.54	$0.71	$22.25
Year 14	$279.15	$66.84	$345.99	$21.98	$0.72	$22.70
Year 15	$284.73	$69.20	$353.93	$22.42	$0.74	$23.15
Year 16	$290.43	$71.65	$362.07	$22.86	$0.75	$23.62
Year 17	$296.23	$74.17	$370.41	$23.32	$0.77	$24.09
Year 18	$302.16	$76.79	$378.95	$23.79	$0.78	$24.57
Year 19	$308.20	$79.50	$387.71	$24.26	$0.80	$25.06
Year 20	$314.37	$82.31	$396.68	$24.75	$0.81	$25.56
20-Year Total	$5,243.14	$1,207.83	$6,450.98	$351.64	$11.58	$363.22
20-Year NPV	$2,658.55	$592.44	$3,250.99	$157.20	$5.18	$162.37

For a full breakdown of "Improved Restoration – Significant Storms" please refer to CLP-AMI-3, page 65, Section (b)(6) – Early Outage Detection which explains the calculation methodology, inputs, and assumptions on how these figures are created.

b) The average annual amortization expenses related to storm restoration (equal to $211.177 million for Rate year 1) were included in Exhibit ACOS CLP-Exhibit-2 (Confidential), Table 9. These costs were treated as the rest of other amortization expenses and were allocated to rate classes according to the allocations of total rate base by class. Therefore, classification between demand and customer-related implicitly followed the same classification as the sum of the components that make up the overall rate base.

c) As provided in Exhibit CLP-AMI-3, including referenced sections and pages 85-92, the Company has quantified and provided descriptions of benefits on a customer-class level

and with respect to advanced rate design that would extend to various components of service at a rate class and individual customer level, but not for these specific rate classes.

d) Please refer to the Company's response in subpart (c).

Date Filed: November 12, 2026

Witness: Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the ACOS Direct Testimony at page 6, lines 11-25.

a. Please provide the meter weighting factors and average installed meter cost by rate class used to develop the meter plant allocation factor, together with the supporting workpapers in Excel format with formulas intact.
b. Please state whether, and how, the Company would update those weighting factors to reflect the cost of AMI meters by rate class once AMI meters are deployed.

Response:

a. Please refer to the Company's response to RRU-033[i].

b. In the ACOS, the AMI meter weighting factors would be updated to reflect the relative differences in installed cost, in current dollars, applicable at the time of deployment, including any communication modules.

Prior Referenced Response:

[i] RRU-033 Question:

(ACOS) Application, Ex. CLP-ACOS-1, Dir. Test. Nieto, p. 7. Provide the average installed meter cost for each rate class. Include the underlying calculations, assumptions and supporting documentation in the response.

RRU-033 Response:

The detailed underlying calculations, assumptions and supporting documentation are included in RRU-033, Attachment 1.

Date Filed: November 12, 2026

Witness: Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:
Please refer to the ACOS Direct Testimony at page 6, lines 1-10.

a. Please explain how the demand allocators for primary and secondary distribution facilities exclude the loads of customers that take service at primary or transmission voltage from the allocation of facilities at lower voltage levels.
b. Please provide the class NCP demands used for each demand allocator, by voltage level.
c. Please identify the number of Rate 39 customers served at each delivery voltage and the number of Rate 57 customers served at each delivery voltage.

Response:

a. The demand allocators for Primary facilities include the total distribution class NCP corresponding to each class. The demand allocators for the Secondary facilities exclude the portion of the NCP load associated with customers served at Primary; this is approximated using the ratio of secondary customers to total distribution customers in the class. All of the demand allocators refer to NCP of customers that take service at distribution level; no NCP for transmission-connected customers was included.

b. The class NCP demands used for each demand allocator by voltage level are included in Exhibit CLP ACOS-2 Confidential, in tab "*Appendix 1.B Allocator_Input"*. See rows 20 and 21, for allocators "NCP_P" and "NCP_S", respectively.

c. The number of Rate 39 distribution customers is 3, all served at Primary. The number of Rate 57 distribution customers is 72, all served at Primary voltage

Date Filed: November 12, 2026

Witness: Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the ACOS Direct Testimony at page 7, lines 11-25, and page 8, lines 1-4.

a. Please provide, by rate class, the change in revenue requirement at equalized rates of return that would result from classifying all costs in FERC Accounts 364 through 368 as demand-related (i.e., the "basic customer method"), relative to the Company's MDS method, together with supporting workpapers in Excel format.
b. Please provide any other analysis the Company has performed in this proceeding of the effect of the basic customer method on class rates of return.

Response:

a. Please refer to OCC-729, Attachment 2 CONFIDENTIAL.

b. Please refer to OCC-729, Attachment 2 CONFIDENTIAL. No additional analysis was completed.

Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 30, lines 6-12.

a. Please identify each non-distribution component of the rates applicable to large commercial and industrial customers that the Company considers time-varying and that, as stated at lines 6-8, "provide additional incentive and opportunity for customer benefit through efficient utilization of electric service."
b. Please state the Company's position on a requirement that EDR participants take service under a new TOU rate with time-differentiated distribution, transmission and generation charges that has not yet been designed or approved, and explain the basis for that position.
c. Please state whether the Company's billing system can currently bill an EDR participant's incremental load under a different rate structure than the participant's pre-existing load.

Response:

a. The transmission, non-bypassable FMCC, CTA and energy supply components of service are all priced on a time-varying (time-of-day) basis. While supply rates depend on whether a customer takes Last Resort Service or competitive supply, these time varying structures are mandatory for larger customers who would take service under the EDR (e.g., Rate 55-Rate 58).

b. To the extent such rate is a general service rate and is the only option compared with existing offerings (that would continue to be available or applicable in the future), it would seem, hypothetically, it would be inevitable that a future EDR participant would be on a time-differentiated rate offering, one way or another (noting, the context of the question contemplates distribution as a time-varying rate, which currently applies for only intermediate, large and MHD EV TOU rate customers).

c. Billing capabilities are currently limited in this regard. The Company performs special handling (i.e., manual) billing for Rate 39 customers, where load is bifurcated, analyzed in detail, and billed under two different rate structures.

Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 29, lines 1-12, and page 31, lines 5-6, and Exhibit CLP-RATES-3 at pages 38-40.

a. Please identify any transmission or supply cost associated with an EDR participant's incremental load that the Company expects would be borne by customers other than the EDR participant, and explain why.
b. Please confirm that, under the Terms and Conditions for Electric Suppliers at pages 38-40 of Exhibit CLP-RATES-3, the hourly load of an EDR participant, including its coincident peak capacity values, would be assigned to the participant's electric supplier (including Standard Service or Last Resort Service) for ISO-NE settlement.
c. Please state whether interconnection, system upgrade or make-ready costs paid directly by an EDR participant (including through a contribution in aid of construction) would be included as a cost of serving the incremental load in determining whether revenues exceed incremental cost of service or in determining the discount cap.

Response:

a. The referenced Rates Panel Testimony on pages 29 and 31 refer to Distribution Service. The charges for transmission and supply for the incremental load of an EDR participant would be the responsibility of that participant, consistent with the applicable rate schedule for service to such participant, and with the applicable provisions of the Company's terms and conditions of service, including those cited in Exhibit CLP-RATES-3.

b. The Company expects that the future provisions of the referenced terms and conditions, and the application of those provisions in determining hourly load and electric supplier assignment would apply in a like manner as current practice, absent any changes in proposed terms and conditions relative to current terms and conditions, or to future practices as applied to an individual customer's electric supplier service arrangement or in supplier load assignment methodologies.

c. Yes. Determination of the portion of upfront costs paid by the EDR participant would be included in the evaluation to determine the level of discount. This can also be viewed as; the level of discount would have a bearing on the portion of such costs that would be paid directly by the participant.

Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 24, lines 18-22, and page 25, lines 1-8.

a. Please state whether the Company has a definition of "data center" or "large-scale computational load" that it would use to determine whether a customer's load is data center load. If so, provide it.
b. Please identify the number of inquiries the Company has received since January 1, 2024 regarding new or expanded load from (i) data centers and (ii) manufacturing or other industrial customers, by size range.

Response:

a. Please see the Company's response to CIEC-036[i].

b. Such information is not readily available.

Prior Referenced Response:

[i] CIEC-036 Question:

With reference to the Panel's response to OCC-464, explain whether:

a. The term "large-scale computational loads" includes only data centers, or if it also may be applied to other non-residential loads.
b. There are specific criteria that Eversource uses to define what constitutes a "data center"? If the answer is in the affirmative, provide and explain the criteria.

CIEC-036 Response:

a. The Company's response relied on "data center" as the context for what is meant by the term "large scale computational load" referred to.

b. There may be many different types of customers and loads whose characteristics fall within the classification of a data center. The State of Connecticut's Office of Legislative research report, "Data Center Energy Impacts and State Responses" refers to a description of a data center as, generally, "a physical facility that houses and runs large computer systems." The report further provides: "A data center typically contains

multiple computer servers, data storage devices, and network equipment to store, manage, process, and transmit large amounts of data". 1 The term "large-scale" provides additional specificity regarding what might be attributable to a specific data center. As stated in response to OCC-464, the Company believes the appropriate treatment of such loads, including whether a specific rate or customer-specific terms are warranted should be determined through deliberations with state agencies when that load materializes.

[1] "Data Center Energy Impacts and State Responses", Connecticut General Assembly, Office of Legislative Research, 2025-R-0164, Mary Fitzpatrick, October 14, 2025

Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 22, lines 14-21.

a. Please confirm that any shortfall in actual distribution revenue relative to the authorized revenue target, regardless of its cause, would be reconciled through the RDM.
b. Please confirm that, as proposed, the RDM rate would be a single per-kWh rate applied to all rate classes, including Rate 39, Rate 57 and Rate 58.
c. For each of the Company's last three RDM reconciliation filings, please provide the total RDM amount and the amount recovered from or credited to each rate class, including Rate 39, Rate 57 and Rate 58.
d. Please explain how a reduction in distribution revenue resulting from a heat pump rate, such as Rate 6 or Rate HP, would be recovered between rate cases, and identify the share that would be recovered from non-residential rate classes.

Response:

a. Differences in revenue between actual and target, and flow through of such differences for charges or credits through the RDM are subject to a prudence review and authorization by PURA.

b. Yes, as proposed and as is currently designed, the RDM rate would be a single per-kWh rate applied to all rate classes, including Rate 39, Rate 57 and Rate 58.

c. Please refer to Table 1 for the requested information, which has been provided in previous RAM filings:

Table 1

	2024 (DN 24-01-03)	2025 (DN 25-01-03)	2026 (DN 26-01-03)
Rate 1	$15,426,873	$7,990,329	$870,234
Rate 5	$3,256,347	$1,686,621	$183,691
Rate 7	$10,701	$5,543	$604
Rate 18	$1,443	$748	$81
Rate 27	$165,744	$85,847	$9,350

Rate 29	$5,296	$2,743	$299
Rate 30	$6,662,626	$3,450,898	$375,840
Rate 35	$1,188,616	$615,642	$67,050
Rate 37	$2,299,083	$1,190,807	$129,692
Rate 40	$196,280	$101,663	$11,072
Rate 41	$29,925	$15,500	$1,688
Rate 55	$1,211,754	$627,627	$68,355
Rate 56	$3,534,218	$1,830,544	$199,366
Rate 57	$1,638,061	$848,431	$92,403
Rate 58	$3,291,659	$1,704,911	$185,683
Rate 115	$105,636	$54,714	$5,959
Rate 116	$150,310	$77,853	$8,479
Rate 117	$60,300	$31,232	$3,402
Rate 39	$534,357	$276,770	$30,143
Rate 119	$13,940	$7,220	$786
Total	**$39,783,171**	**$20,605,642**	**$2,244,179**

d. Please refer to the Company's response to OCC-473[i]. The Company has not proposed a Rate HP. Please refer to Table 2 below for the allocation percentage of the RDM rate based on billing determinants currently in effect.

Table 2

Rate	Allocation %
1	38.8%
5	8.2%
7	0.03%
18	0.0%
27	0.4%
29	0.01%
30	16.7%
35	3.0%
37	5.8%
40	0.5%
41	0.1%
55	3.0%
56	8.9%
57	4.1%
58	8.3%

115	0.3%
116	0.4%
117	0.2%
39	1.3%
119	0.04%
Total	100.0%

Prior Referenced Response:

[i] OCC-473 Question:

(Rate 6 – Residential Space Heating Rate) Refer to Exhibit CLP-RATES-1, at 23-24. Please state whether the Revenue Decoupling Mechanism is designed to capture any revenue shortfall arising from Rate 6 enrollment diluting Rate 1 revenues. If so, explain how Rate 6-driven revenue loss will be treated under the RDM and which customer classes ultimately bear that cost.

OCC-473 Response:

The Revenue Decoupling mechanism is designed to reconcile differences in aggregated (i.e.,. total) actual vs. targeted revenues, and not specifically to capture such revenue shortfall that may occur. While the question does not define or explain what is meant by diluted revenues, if the context of an assumed difference in revenue is due to the migration of Rate 1 customers to Rate 6, such migration may in a given month result in higher revenue for first block kWh sales, and lower revenue for second block kWh sales, which potentially include both kWh sales that would otherwise have been charged under Rate 1 and kWh sales associated with incremental, new heat pump load. The Company does not agree that Rate 6 enrollment which reflects increased kWh sales would reduce overall revenue compared with revenue under Rate 1 which would exclude such increased kWh sales.

Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to Exhibit CLP-RATES-3 at pages 186-187 (Transmission Adjustment Clause).

a. Please describe how the Company allocates its transmission revenue requirement among rate classes in setting retail Transmission Service Rates, and provide the allocation factors used for the rates proposed in this proceeding.
b. Please explain the basis for the difference between the proposed Transmission Service Rates for Rate 5 and Rate 1.
c. Please explain how any under-collection of transmission revenue from a particular rate schedule is recovered through the TAC reconciliation, and state whether it is recovered from all rate classes.
d. Please explain how an under-collection of transmission revenue resulting from a 75% reduction in the winter (November through March) Transmission Service Rate for heat pump customers, as proposed for Rate HP, would be recovered.

Response:

a. Please refer to the Company's response to UCONN-024[i] for the requested information.

b. The respective allocation of costs and rate design for these rate classes are dependent on their specific demand allocation factors and billing determinants, which in combination can result in a material difference in the rate per kWh of the Transmission service rates in each rate class.

c. Please refer to the Company's response to UCONN-024 for the requested information.

d. The Company has not proposed a Rate HP. For its alternative space heating rate, Rate 6, the Company has not proposed a percentage reduction to transmission rate. The allocation of cost responsibility, and setting of the transmission rate for such service would be based on that class's transmission cost allocation and rate design, as applied in developing the transmission rate for Rate 1.

Prior Referenced Response:

---

[i] UCONN-024 Question:

(Affordability & Customer Engagement) Refer to Exhibit CLP-ELP-1 at pp. 25-26 which states that "transmission costs are shared across the region" and are "proportionally allocated" to Connecticut. Exhibit CLP-RATES-3 at pp. 186-187 describes the overall calculation of the total Transmission Adjustment Clause ("TAC").

a. Please explain the formula and methodology used to apportion the total costs of transmission across customer classes in the Connecticut service territory.
b. Please explain how this methodology is consistent with cost-causation and fairness principles.
c. For each of Rates 55, 56, 57, and 58, please provide (i) the percentage of total TAC revenue allocated to each rate class, and (ii) the total dollar amount of TAC revenue collected from each rate class, in each case for the most recent TAC reconciliation period.

UCONN-024 Response:

a. Please refer to UCONN-024, Attachment 1, for the Transmission exhibits provided in the Company's most recent RAM filing, Docket No. 26-01-03.

- Page 1 shows the determination of the average Transmission rate on line 31.
- Page 2 shows the time-of-use breakout for applicable rate classes.
- Page 3 shows a comparison versus the current and proposed Transmission rates by rate class.
- Page 4 shows the Transmission Allocation. The Transmission Revenue Target (cell F13) is calculated by multiplying the average Transmission rate from page 1 by the Rate Year total sales. This Revenue Target is allocated to each rate class based on a 12 CP kW Demand Allocator (Columns C and D).

b. The Company uses a 12 coincident peak ("12 CP") allocation factor to assign transmission revenue requirements to rate schedules. This methodology is designed to reflect the methodology used in the development of the NEPOOL OATT revenue requirement and the resulting charges billed to the Company for transmission service under that tariff. From this perspective, the allocation is a "financial" nature, in that it is based only on the amount billed to the EDC's (noting, it is the amount billed first to the transmission service customer and then allocated to CL&P that is used for determining the corresponding class allocation.

   Despite the diversity of customer loads that make up the monthly peak, or the load levels or utilization of the transmission system by individual customers throughout all other hours of a given month, where such demands may be greater than during the system peak, it is only the single monthly peak that is applied using this allocation method). Unlike with a resource-based distribution cost allocation, the billed transmission charge is what is being allocated. Under the current paradigm, the allocated charges and coincidence of demand for determining the share of load contributing to such charges provides a reasonable basis for allocation of costs. To the extent consideration is given to alternative approaches for class cost allocation, a review of underlying costs and consideration of utilization of the system that such charges represent might be of interest with regarding to equitable allocation, along with other rate design principals to evaluate.

c. Please refer to UCONN-024, Attachment 1, for the requested information.

Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to Exhibit CLP-RATES-3 at page 186 (Transmission Adjustment Clause), which refers to "the transmission costs of acquiring such services."

a. Please identify the billing determinants ISO-NE uses to assess Regional Network Service and Local Network Service charges to the Company, including whether those charges are based on the Company's network load at the time of the monthly peak.
b. Please provide the Company's monthly network load used to determine Regional Network Service charges for each month from January 2023 through the most recent month available.
c. Please provide the Company's estimate of the change in its annual Regional Network Service charges that would result from a 1 MW increase in its network load at the time of the monthly peak in each of the months of November through March.

Response:

a. CL&P's monthly regional network load reported to ISO-NE is derived from its network load at the time of the monthly transmission peak. Both the Regional Network Service (RNS) and Local Network Service (LNS) charges use this peak-load billing determinant multiplied by the applicable RNS and LNS rates applied to calculate the respective charges each month.

b. The following table provides the monthly network load used to determine Regional Network Service charges for January 2023 to September 2026.

CL&P's Monthly Peak Network Load (MW)				
Month	**2023**	**2024**	**2025**	**2026**
January	3,037	3,319	3,588	3,628
February	3,509	3,046	3,423	3,702
March	2,849	2,702	3,068	3,271
April	2,807	2,677	2,734	2,949
May	2,545	3,098	2,524	3,617
June	3,460	4,340	4,955	4,322
July	4,292	4,523	4,734	4,831
August	3,671	4,318	4,095	4,421
September	4,521	2,972	3,169	3,510
October	2,994	2,532	2,768	
November	3,026	2,726	2,915	
December	3,027	3,456	3,541	

c. Based on the annual RNS rate, a 1 MW increase in CL&P's monthly network load would increase the RNS charges as follows:

- 2023: $11,804 per month.
- 2024: $12,863 per month.
- 2025: $15,440 per month.
- 2026: $14,802 per month.

Date Filed: November 13, 2026

Witness: Lavelle A. Freeman, Gerhard Walker, Juan F. Martinez and Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:
Please refer to the MCOS Direct Testimony at page 6, lines 9-14; page 18, lines 4-13; and page 19, lines 1-4.

a. Please provide any analysis or forecast the Company has of when its system, or individual bulk or distribution substations, would become winter peaking as a result of heat pump adoption, including for years after 2031.
b. Please identify the bulk substations that experienced an annual peak load in December or January in any of the years 2022 through 2025.
c. Please provide the heat pump adoption assumptions used in the MCOS study's analysis of load shapes through 2031.
d. Please explain the statement at page 19, lines 3-4, that "[i]n the longer-term, additional electrification will shift more cost responsibility to the winter evening hours," including the time frame the Company expects.

Response:

a. The Company has not developed a substation-level forecast that identifies when its system or individual substations would transition to winter peaking as no such transition is currently projected to occur within the 10-year forecast horizon. However, starting with the 2028 vintage forecast, the Company is planning to develop a stand-alone substation-level winter coldest day load forecast.

b. The Company currently has only one substation where winter and summer peak are on par and no substations where the winter peak exceeds the summer. The station in question is in Waterbury.

c. Ms. Nieto used ISO-NE's 2026 CELT Report assumptions of heat pump winter peak MW additions for the state of CT (tab 1.7, *Table 3 Winter Peak*). ISO-NE estimates a winter peak load impact of 224 MW by 2030/31. The MCOS used 80% of that value (179.2 MW) reflecting the portion of the state load that is in Eversource's service area, as the highest hourly electrification load expected in Eversource by the 2030/31 winter.

d. Ms. Nieto's referenced statement in her direct testimony is alluding to the expected impact of increased adoption of heat pumps for space heating on hourly load shapes over time. The load profile for space heating used in the MCOS analysis assumes electric space

heating will increase winter loads in all 24 hours, but more markedly in the morning, between 5 and 8 am, followed by a less noticeable but still impactful increase in the evening hours after about 5 pm. The referenced statement in her testimony emphasizes the winter evening hours because the focus of her analysis is the next five years, and currently the highest winter loads occur in the evening of the coldest winter months of December and January. In the near term, the winter evening loads will hold higher cost responsibility relative to the winter morning, though this situation will begin to reverse after 2031.

Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 31, lines 14-24; page 32, lines 1-19; and page 36, lines 1-9.

a. Please provide the Company's estimate of the number of Rate 6 participants and the resulting annual reduction in distribution revenue relative to Rate 1 for each year from 2027 through 2031, with supporting workpapers.
b. Please explain how any reduction in distribution revenue resulting from Rate 6 would be recovered, including whether any portion would be recovered from non-residential rate classes through the RDM or otherwise.
c. Please provide the number of the Company's residential customers known to have installed heat pumps before January 1, 2026 (e.g., through Energize CT incentive records), and the Company's estimate of their annual winter usage.
d. Please estimate the annual revenue reduction that would result if winter usage from end uses other than heat pumps, such as electric vehicle charging, received the Rate 6 Block 2 rate as described at page 36, lines 3-7.

Response:

a. Rate 6 is a proposed rate. The Company has not prepared an estimate of the number of participants during 2027 through 2031.

b. Analysis of changes in revenue and impacts should be performed holistically, and not only with respect to revenue reductions. When compared with revenue from Rate 1, which would be designed at the conclusion of this case on the premise of no customers enrolled in Rate 6, and as approved by PURA, a customer qualifying for and switching to Rate 6 would receive service under different rates (e.g., as proposed, there would be a different customer charge and tier 1 and tier 2 distribution rates). Revenue from these charges will vary compared with the same service Rate 1 depending on both price differences and monthly usage. Rate 6 customer charges and tier 1 pricing determined, on an annualized basis, and utilizing annual Rate 1 usage. As shown in Exhibit CLP-RATES-6, page 3, the average use per customer for residential base load (prior to incremental load) is below the proposed 700 kWh threshold during 3 of the winter months, and slightly above during the remaining 2 months, and these characteristics are represented in the design of Rate 6. Based on those usage assumptions, class revenue would be the same in total, yet would

vary among the various components. Moreover, differences in actual revenue compared with rate design (i.e., target) levels would be reflected in variances (charges or credits) over the course of a given year (which is the overall basis upon which the Company's revenue decoupling mechanism operates, and not in differences in revenue from collective charges under Rate 1 and Rate 6. Incremental revenue, including that associated with tier 1 or tier 2 usage, would contribute to revenue that in total factor into the evaluation of revenue decoupling mechanism charges or credits. A narrower focus of evaluating only reduced revenue fails to capture the other dynamics of other rate and revenue components, and impacts that may result from switching and intrinsic incremental load growth associated with addition of a heat pump that is included as part of the total, whole house load of a Rate 6 customer.

c. Please refer to the Company's response to CLF-SC-003[i].

d. The impact of such usage would, all other things being equal, be included in the incremental load discussed in subpart b. Recognizing the requirement for participation in Rate 6 is to add and utilize an air source heat pump for electric space heating, and that Rate 6 is a whole house rate, the EV or other load would be part of, but not distinguishable from the incremental load. The extent of any revenue reduction in, say, a given month, would be dependent on total whole house usage, the levels of end use contributing to that load, and the levels of consumption in the base and incremental usage tier of the tail block. Refer to the response to subpart b regarding the level of revenue in both tiers and whether there is more or less incremental revenue.

Prior Referenced Response

[i] CLF-SC-003 Question:

For the Test Year in this proceeding, please provide:

a. the number of residential electric customers with a heat pump as their primary heating source;
b. the total electricity consumption (kWh) of these customers;
c. the total electric delivery revenue attributable to these customers, in the aggregate.

The Company may provide this information either as a summary table or as the underlying billing and customer data necessary to derive it (e.g., anonymized billing-quality data identifying each customer's heating source, together with that customer's kWh consumption and delivery revenue for the period). Please provide this information in CSV format or in live Microsoft Excel format (with all formulae intact). If the Company does not possess the information necessary to produce any of the three items requested (heat pump customer count, consumption, or delivery revenue), please state specifically which item(s) the Company is unable to provide, and explain in detail why not for each. If the Company is not able to produce all three items requested for the Test Year, but is able to do so for a different time period, please provide these figures for the most recent time period available.

CLF-SC-003 Response:

Since the Company does not track the heating sources of its customers, the Company has evaluated data collected from Energy Efficiency rebates issued to customers who (1) installed a qualifying heat pump at their residence and (2) submitted for a rebate. This information does not represent all customers who may have heat pumps.

a. Evaluation of data from rebate program which began in 2023 indicates there have been approximately 4,400 customers who have received heat pump rebates that indicate full displacement of other heat sources and use heat pumps as their primary heating source.

b. The Company does not know the total number of residential electric customers utilizing heat pumps as their primary heating source during the Test Year and accordingly is unable to query those customers' total kWh consumption or determine or estimate total delivery revenue.

c. Refer to the Company's response to subpart (b), above.