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

JOINT REBUTTAL TESTIMONY OF

EDWARD DAVIS, KIMBERLY R. PARSONS, AMPARO NIETO

Rate and Tariff Amendments, Cost of Service Study and Heat Pump Rate Design

On behalf of

The Connecticut Light and Power Company
d/b/a Eversource Energy

November 18, 2026

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I. INTRODUCTION

Q. Please state the names of the witnesses on the Rates Rebuttal Panel.

A. The Rates Rebuttal Panel is comprised of Edward Davis, Kimberly R. Parsons, from the Rates Group at Connecticut Light and Power Company d/b/a Eversource Energy ("CL&P" or the "Company"), and cost of service expert witness Amparo Nieto, Director at BRG's Energy Practice. We are jointly providing this rebuttal testimony on behalf of the Company.

Q. Mr. Davis and Ms. Parsons, have you previously submitted testimony in this proceeding?

A. Yes. On July 14, 2026, we submitted direct, pre-filed testimony to the Public Utilities Regulatory Authority ("PURA") on behalf of CL&P in support of its application for approval of amended rate schedules. Our direct, pre-filed testimony was designated as Exhibit CLP-RATES-1, accompanied by the below-listed exhibits.

Exhibit	Purpose/Description
Exhibit CLP-RATES-2	Rate Design and Revenue
Exhibit CLP-RATES-2.1	Comparison of Distribution Revenue at Current vs. Proposed Rates
Exhibit CLP-RATES-2.2	Comparison of Current Rates vs. Proposed Rates
Exhibit CLP-RATES-2.3	CL&P Proposed Test Year and Rate Year Revenue at Current and Proposed Rates

Exhibit	Purpose/Description
Exhibit CLP-RATES-2.4	Proposed Test Year and Rate Year Revenue Calculations by Rate Schedule (Schedule E-2.4)
Exhibit CLP-RATES-2.5	Standard Service Typical Bills by Rate Schedule (Schedule E-2.3)
Exhibit CLP-RATES-2.6	Last Resort Service Typical Bills by Rate Schedule (Schedule E-2.3)
Exhibit CLP-RATES-2.7	Street Lighting Rate Design
Exhibit CLP-RATES-2.8	Rate 7 Time-of-Day Calculations
Exhibit CLP-RATES-2.9	Test Year Ending 2025 Actual Revenues
Exhibit CLP-RATES-2.10	Test Year and Rate Year Revenues at Current Rates (Schedule E-2.1)
Exhibit CLP-RATES-2.11	Test Year and Rate Year Revenues at Proposed Rates (Schedule E-2.0)
Exhibit CLP-RATES-2.12	Decoupling Targets
Exhibit CLP-RATES-2.13	MRCC Calculation
Exhibit CLP-RATES-2.14	Pole Attachment Rate Calculations
Exhibit CLP- RATES-3	Clean and Scored Tariffs (Schedules E-1.0 and E-1.1)
Exhibit CLP- RATES-4	Bill Frequency Reports (Schedule E-2.5)
Exhibit CLP- RATES-5	Sales Forecast
Exhibit CLP- RATES-6	Rate 6: Optional Residential Space Heating Rate
Exhibit CLP-RATES-7	Residential Customer Poverty Threshold Analysis
Exhibit CLP-RATES-8	TVR Customer Engagement Plan

Our direct testimony in this proceeding included proposed rate design and tariff amendments that incorporate several new rates initiatives, namely an optional residential space heating rate for customers adopting heat pumps ("heat pump rate") and an economic development rider ("EDR"). Proposed amendments to certain provisions of tariff riders, and to provisions and miscellaneous fees and charges of the Company's Terms and Conditions for both Delivery Service and Electric Suppliers were also presented. Additionally, we addressed directives and compliance associated with cost allocation, rate structure and rate design including time varying rates for designated rate classes and more broadly.

Q. Ms. Nieto, have you previously submitted testimony in this proceeding?

A. Yes. On July 14, 2026, I submitted direct testimonies to PURA on the Company's Allocated Cost of Service ("ACOS") study, and separately on the Marginal Cost of Service ("MCOS") study. I led the development of both cost of service studies on behalf of the Company, including the time-differentiation analysis. My direct testimony also discussed the appropriate interpretation of the resulting marginal cost estimates to guide the Company's distribution rate design improvements for higher efficiency in price signals, and cost rebalancing among rate components to address intra-class cross-subsidies, subject to gradualism needs and other constraints. My direct, pre-filed testimonies were designated as Exhibits CLP-ACOS-1 and CLP-MCOS-1.

Q. What is the purpose of this panel's joint rebuttal testimony?

A. The purpose of our testimony is to respond to various intervenors' rate design and cost of service study method recommendations and statements in response to our direct testimonies. Specifically, this testimony responds to claims made by Mr. James R. Dauphinais, on behalf of Connecticut Industrial Energy Consumers ("CIEC"); Ms. Melissa Whited on behalf of the Office of Consumer Counsel ("OCC"); Mr. Juan Pablo Velez on behalf of the Conservation Law Foundation ("CLF"); and Mr. Eben Perkins on behalf of the University of Connecticut ("UCONN"), on issues regarding the

Company's proposed EDR and alternative electric space heating rates, several aspects of the ACOS study, and other rate design and tariff proposals.[1]

Q. Did the above-listed intervenors have concerns with specific aspects of the proposed rates?

A. Yes. The intervenors listed above provided various recommendations on eligibility and application that are discussed in more detail in this testimony. Overall, intervenor testimony reflects broad stakeholder agreement that both an economic development rider and heat pump rate could provide meaningful customer benefits. However, Mr. Velez on behalf of CLF and Ms. Whited on behalf of OCC submitted testimony recommending PURA reject the Company's Rate 6 and direct a different design of the heat pump rate. No intervenor opposed the general concept of an EDR, however several intervenors propose modifications to the design. This degree of agreement supports moving forward with workable rate designs while addressing the specific implementation concerns raised in testimony.

Q. Are you presenting any exhibits as part of your rebuttal testimony?

A. Yes. Exhibit CLP-RATES-REBUTTAL-2 accompanies this testimony, presenting a redlined version of the Company's Performance-Based Multi-Year Rate Plan ("PBMRP") tariff.

[1] The Company does not respond to every issue raised in the intervenor testimonies. Silence on any issue should not be construed as agreement on any issue.

Q. How is your testimony organized?

A. Our testimony is organized into the following sections:

- Section I is the introduction.
- Section II discusses the Company's response to the intervenors' comments on EDR.
- Section III responds to certain aspects of the proposed alternate residential space heating rate (Rate 6) rate design comments.
- Section IV discusses specific comments from the intervenors on the ACOS study and their proposed alternative distribution plant classification and allocation methods.
- Section V responds to AMI cost classification comments and recommendations.
- Section VI addresses issues related to potential new distribution and transmission rate design for commercial and industrial ("C&I") customers.
- Section VII provides a modified PBMRP Tariff to address intervenor issues.
- Section VIII is the conclusion.

II. PROPOSED ECONOMIC DEVELOPMENT RIDER

Q. Please summarize the Company's proposal regarding the introduction of an Economic Development Rider.

A. The fundamental components of the EDR include a provision for determining customer eligibility and qualification, a schedule of discounts and term of service and discount, as well as reference to a Service Agreement. The EDR as proposed is a form of rider which can be utilized for establishing a schedule of discounted rates and charges for customers with incremental new or expanded service requirements. The EDR is intended to be applied to rates applicable to serving the incremental load of qualifying large commercial and industrial customers. A schedule of discounted rates would be determined on a customer-specific basis, pursuant to a service agreement entered into

under the rider. Consistent with established regulatory principles, the EDR is intended first and foremost to benefit ratepayers through improved system economics and affordability, while also supporting broader economic development objectives.

The EDR shall be available to new and existing large commercial and industrial customers that demonstrate incremental load growth. A New Customer is a customer establishing electric service within the service territory that has not taken service within the prior twelve months. An Existing Customer is a customer that expands operations and demonstrates measurable incremental load above a defined baseline.

As proposed, eligibility is limited to customers taking service on the Company's large general service rates — Rate 57 for manufacturing customers and Rate 58 for non-manufacturing customers — with demand generally exceeding one megawatt ("MW"). The proposed EDR is limited to incremental (i.e., new or expanded) load only, and discounts shall not be available relative to existing load. The EDR is not available to any other service class or for load retention purposes. Of note, there are a limited number of Rate 39 customers, and only three of whom receive distribution level service. No new customers are authorized to participate in Rate 39. Rate 39 is a somewhat dynamic rate that allows incremental load, above an interruptible contract demand level, to be served under a firm service rate. This incremental load may be eligible for enrollment under the EDR. This demonstrates the need for case by case analysis of eligibility for the EDR, including but not limited to an examination of (1) the differentiation and extent of firm service load, (2) specific electric service analysis

and review to ensure physical requirements and determination of any upgrades, equipment, etc. are identified and the economics and customer contributions, if any, relative to the level of discount and costs of any construction work are established up front. Further, in order to qualify, the Company proposes that a customer must as a minimum demonstrate that its project: (i) involves new or expanded operations resulting in incremental load[2] that supports system efficiency; (ii) provides economic value to customers within its service territory, including job creation or capital investment; and (iii) is designed, further, to support regulatory policy objectives, and to provide value during the term of project participation in the EDR. Customers looking to qualify will also be required to provide the Company with information describing why electric load is increasing, anticipated investment, and changes in employment levels or jobs expected to be created, as well as a narrative describing what impact the EDR had on the customer's expansion or decision to add new load.

The Company also proposes a declining, time-limited discount applied to incremental load over a five-year term, consistent with the declining structure proposed in the Company's prior economic development rate.

Q. Do the intervening parties support the introduction of an EDR?

A. Yes. Mr. Dauphinais on behalf of CIEC and Ms. Whited on behalf of the OCC submitted testimony expressing support for the introduction of the EDR, subject to

[2] Incremental load is defined as usage above a defined baseline for existing customers; and as total new usage associated with the project for new customers.

modifications to the eligibility criteria, schedule of discounts and term of service and discount, and enrollment procedures applicable to the EDR.

Q. Please describe the recommendations presented by Mr. Dauphinais to modify the EDR as proposed by the Company.

A. Mr. Dauphinais recommends a number of modifications to PURA to replace the provisions that leave eligibility to CL&P's discretion with "clear, objective criteria," including an objective hurdle rate analysis, including setting a single minimum incremental load threshold applicable to all participants rather than establishing that threshold on a contract-by-contract basis.[3] Specifically, Mr. Dauphinais recommends PURA direct the Company to:

1. Remove the requirement in Qualification 1(C) that a facility provide "added value to the Company's service territory, as determined by the Company," so that any C&I facility meeting the minimum incremental load threshold may qualify, subject to the same exception for customers directly participating in local commerce that PURA approved for the United Illuminating Company[4] ("UI");[5]

2. Replace the "satisfaction of the Company" standard in Qualification 3 with a requirement that the customer provide a narrative description of why its load is increasing or, for a new customer, the role of the EDR in its decision to locate in CL&P's service territory, similar to the application requirement PURA approved for UI;[6]

3. Remove Condition 1 (partial requirements refund provision) or in the alternative, direct the Company clarify that a customer's choice of energy

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[3] Dauphinais at 7.

[4] *See* Decision, Aug. 25, 2023, Docket No. 22-08-08, Application of The United Illuminating Company to Amend Its Rate Schedule.

[5] Dauphinais at 8.

[6] Dauphinais at 10.

supplier does not affect its eligibility for the EDR or trigger any refund of discounts;[7]

4. Replace Condition 2 with a requirement that the customer participate in at least one clean energy, grid modernization or energy efficiency program, as PURA required for UI;[8]

5. Remove Condition 3, requiring an applicant seek other economic development assistance, as a condition of eligibility;[9]

6. Replace Condition 4 with an objective hurdle rate analysis;[10] and

7. Remove Condition 7, requiring 10% removal.[11]

Further, Mr. Dauphinais recommends PURA establish the EDR discount percentages in this proceeding, specifically a discount that is fixed over the five-year term at percentage levels no lower than the 15% base discount and 20% discount for Distressed Municipalities and Environmental Justice Communities, as recently approved by PURA for UI. [12,13] Mr. Dauphinais recommends the EDR be further revised to provide participants one opportunity to extend the discount for an additional five-year term, subject to an updated hurdle rate analysis showing that the revenue from the

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[7] Dauphinais at 11-12.

[8] Dauphinais at 12.

[9] Dauphinais at 12.

[10] Dauphinais at 9-10.

[11] Dauphinais at 12-13.

[12] PURA has previously rejected a defined tier system for determining discount levels. in Docket No. 22-08-08. *United Illuminating Company*, Docket No. 22-08-08 (2023). Instead, UI ultimately developed an application process that includes asking potential customers about historic load levels, a narrative about why load is increasing, employee headcount, data regarding expected employment increases, data regarding expected capital investment, and any information regarding participation in energy efficiency, clean energy, or grid modernization programs. Id. It is then incumbent on UI to decide if the customer should be eligible for the rate. Id. The Company is seeking a similar degree of flexibility to confirm economic benefits and determine customer eligibility. Id.

[13] Dauphinais at 14-16.

incremental load at the discounted rate will continue to exceed the incremental cost to serve that load.[14] He also recommends that the phrase "at any service location" should be clarified so that it does not prevent a separate, later expansion at the same service location from qualifying for its own EDR discount.[15] While Mr. Dauphinais does not oppose review of eligibility on a contract by contract basis, he recommends the Company be required to provide a written explanation to any customer whose EDR application is denied, and report annually to PURA the number of EDR inquiries, applications, approvals and denials, similar to the information PURA required UI to include in its annual EDR report.[16]

Last, Mr. Dauphinais recommends PURA direct CL&P to adopt a load retention special contract policy substantially similar to the policy PURA approved for UI in Docket No. 24-10-04.[17]

Q. Please describe the recommendations presented by Ms. Whited to modify the EDR as proposed by the Company.

A. Similar to Mr. Dauphinais, Ms. Whited also recommends the Company be required to establish fixed discount levels for the EDR, specifically a 1) 20 percent discount for facilities sited in an Environmental Justice Community and a 2) 15 percent discount for facilities sited in other communities, with a discount cap of 50 percent of the net present

[14] Dauphinais at 16.

[15] Dauphinais at 16.

[16] Dauphinais at 10, 18.

[17] Dauphinais at 18-26.

value of incremental revenues.[18] Additionally, Ms. Whited recommends PURA require EDR customers to take service on an enhanced time-of-use ("TOU") rate, to be filed by Eversource within six months of a final decision in this proceeding.[19] Last, Ms. Whited recommends PURA require the EDR exclude data centers from qualifying for the rider.

Q. Do you agree with the recommended changes regarding eligibility criteria to receive the EDR rate proposed by Mr. Dauphinais?

A. Overall, no. We reiterate that establishing criteria for qualification for the EDR can be complex, and potentially carry significant administrative obligations, particularly regarding the process for qualification and implementation. As part of the review of this proposal in this proceeding, the Company intends to seek further review with PURA regarding the administrative process and support needed for reviewing and qualifying applications and ongoing administration, as well as opportunities for rider design and qualification that can bring efficiencies to the process of accepting and enrolling prospective customers as rider participants.

In order to effectively implement the EDR, the Company will need to evaluate each application on a case-by-case basis. However, Mr. Dauphinais, in his testimony, seeks to create bright-line standards of objective criteria, as well as remove barriers, for customers to qualify for the EDR. Specifically, Mr. Dauphinais requests removal of

[18] Whited at 42-45.

[19] Whited at 40-41.

the criterion of "added value to the Company's service territory, as determined by the Company" as well as replacement of the requirement of "satisfaction of the Company" with a narrative description of why its load is increasing or, for a new customer, the role of the EDR in its decision to locate in CL&P's service territory in Qualification 3.[20]

It is necessary for the Company to retain flexibility to approve certain customers for eligibility of the EDR. The Company is proposing the EDR in this case because of the beneficial economics of such a rate and its potential positive impact on affordability. Bringing new, incremental electric load online would be expected to help put downward pressure on rates by providing more variable units over which to spread fixed costs. From a rate perspective, this can be achieved when the economic development rate is set above the marginal cost to serve the new load. The Company considers the results from its most recent marginal cost study as a guide and basis on which to set the economic development rate so that it has the intended positive affordability impacts.

The Company will require an applicant to describe in writing and demonstrate during the term of service that receiving a discount under the EDR is a decisive factor in their decision to add new or incremental load during the term of service under the EDR. An

[20] Qualification 3 requires a customer demonstrate to the satisfaction of the Company that concessions provided by the EDR, either alone or in conjunction with concessions from others provide a significant incentive to cause the Customer to add the Incremental Load in the Company's service area.

explanation of the reason and characteristics of such new or incremental load, and of why an EDR discount is needed as a prerequisite for sitting or expansion of load in the Company's service area is also required.

From the Company's perspective, it is possible to achieve multiple objectives with an EDR. In addition to helping promote customer affordability, the EDR is intended to help spur economic development in the state. Attracting new load can have the beneficial economic impact of job creation, increased capital investment, and higher tax revenue for the state.

However, achieving this objective while maintaining the principles of fair rate design requires careful consideration of individual applicants and their integration of new or incremental load into the existing system. In forming the proposed EDR, the Company considered that any final rate design should be administratively practical and capable of implementation without imposing unreasonable costs or operational burdens on the Company. The value of additional targeting or customization should therefore be weighed against the systems, staffing, verification, and ongoing administrative requirements needed to support it. Additionally, the rate design details should be scrutinized to ensure that they continue to support affordability and avoid unintended consequences.

Q. Why does the Company oppose setting a single minimum incremental load threshold applicable to all participants, rather than establishing that threshold on a contract-by-contract basis?

A. For EDR contracting purposes with existing customers, the baseline is set by the customer's existing load and a contract demand: load up to the contract demand is billed at otherwise applicable rates, and load above the contract demand is treated as incremental and eligible for the EDR. To reserve the EDR for meaningful expansions, a minimum incremental-load threshold would apply, established in the contract. The minimum amount of new load eligible for the new rider is based on service under our large general service rate schedules.

Discretion allows the Company to consider the facts and circumstances of each application while remaining accountable for demonstrating that approved discounts are consistent with the rate's economic-development objectives as well as the Company's affordability goals.

Q. Why did the Company decline to propose a fixed discount level?

A. The Company considered a set of fixed, declining factors, but did not elect to propose this pathway without additional data from specific use cases. As a general framework for any negotiation, the Company considers discounts to distribution rates equating to 25% in year 1 with 5% decrements in each of the 4 subsequent, sequential years, terminating upon completion of the 5-year period, to be a reasonable initial schedule. Relative to this schedule, both the discounts (higher or lower) and the term (5 years is the maximum) could potentially be adjusted, with consideration of both the

aforementioned regulatory objectives and the need to achieve revenue sufficiency pursuant to certain factors[21], assuring no shifting of costs to other customers. In turn, further discount levels may be considered commensurate with a demonstrated positive system benefit (e.g., contribution to fixed costs while remaining above marginal costs). This portion of analysis applies directly to utility service under applicable tariffs and projected incremental load that would be served pursuant to the EDR. Additional discounts, such as those related to facilities sited in an Environmental Justice Community or other communities, or a mechanism such as a discount cap of 50 percent of the net present value of incremental revenues, could be incorporated into the analysis and determination of the ultimate schedule of discounts, if and as directed to do so by PURA.

Further, rigid tiers could exclude projects that advance the objectives of the rate but do not fit neatly within standardized thresholds, while also increasing the complexity of application review and administration.

The record does not demonstrate that the Company's proposed declining five-year discount is insufficient to induce qualifying investment or expansion. In fact, similar declining discounts with defined end dates are used by other large investor-owned

[21] Customers would be responsible for all costs associated with the installation of a new service pursuant to the Company's new business policies. These costs are determined when such applications are made to the Company and would vary depending on the site conditions and work required for each location. Discounted revenues contemplated under the term of an EDR would be considered in the context of any contribution in aid of construction ("CIAC") or similar evaluation for a prospective EDR applicant.

utilities, reflecting the principle that the incentive should help initiate new activity without becoming a permanent subsidy.

In general, the Company seeks to set the EDR low enough and for enough time to achieve a desired outcome, in this case moving to or expanding within CL&P service territory but not so low as to remove the benefit of these customers contributing to existing fixed costs, a key affordability benefit of encouraging new and added load. If the EDR is too discounted, or if it continues for longer than necessary to encourage development in CL&Ps territory, this becomes an issue of free-ridership where the Company is providing a discount that customers don't require, to the detriment of other customers.

The record likewise does not establish that customers require an optional additional five-year term. Extending the discount could create free-ridership concerns if the initial discount was sufficient to influence the customer's decision but the customer continues to receive reduced rates after the inducement is no longer necessary. PURA declined a similar proposal to allow a longer than five-year EDR term as part of the Order in Docket No. 22-08-08.

Q. Were there concerns in intervenor testimony that the EDR will have an impact on peak usage?

A. Yes. Ms. Whited suggested that the EDR may not necessarily steer customers away from using energy during peak times.[22] This is not a concern, however, because

[22] Whited at 40.

customers on Rates 57 and 58 already take service under TOU rates, so they have an existing price signal to manage usage and avoid higher-cost on-peak periods. The EDR therefore does not necessarily require a separate time-varying component to encourage load management. Whited describes these price signals as "weak" but does not offer any evidence showing that the existing time of use rates are not discouraging peak usage.[23]

Q. Were there concerns about whether customers would be able to understand the parameters of the rate?

A. Yes. Mr. Dauphinais states that a fixed discount is the easiest for customers to understand.[24] Additionally, Ms. Whited suggests that a fixed discount rate would be "simpler to understand than a declining discount…"[25] However, the Company does not share this concern because customers served under Rates 57 and 58 are generally among the largest and most sophisticated customers in the service territory. These customers commonly have facility and/or energy managers or comparable expertise and would be capable of evaluating the EDR, understanding its declining structure, and incorporating the rate into their business and energy-management decisions. Moreover, the ability to provide a discount, while still on a declining schedule, that is greater than such standard amount, and that is further adjusted potentially to address the costs to interconnect or upgrades, help achieve a balance with each customer's

[23] Whited at 43.
[24] Dauphinais at 15.
[25] Whited at 44.

specific requirements. Once established, the schedule is known and, in that respect, fixed, and would then be applied according to the actual operations of the facility.

Q. Do you have concerns regarding Mr. Dauphinais' recommendation to remove Condition 7 (i.e., removal from the rate if, in each of three consecutive months, its kilowatt-hour energy usage is less than 10 percent greater than its energy usage in the corresponding months of the Base Period)?

A. Mr. Dauphins argues that Condition 7 effectively requires an existing customer's total usage to remain at least 10% above its Base Period usage, which is problematic because an expansion that is significant in absolute terms may represent less than 10% of a large customer's existing usage. Additionally, Mr. Dauphinais states that Condition 7 does not account for normal variations in industrial operations, such as maintenance outages, production schedules, and seasonal or market-driven changes in output, that can temporarily reduce usage over a three-month period.

Inclusion of this condition provides some guardrails, although has the potential to be overly prescriptive and require further review and potential adjustment. The criteria of 10 percent relative to Base Period usage provides a definitive basis for maintaining EDR qualification, and without some criteria qualification is more subjective and administratively inefficient. We recommend maintaining some form of criteria rather than its removal.

Q. Is the Company amenable to providing a written explanation to any customer whose EDR application is denied, and reporting annually to PURA the number of EDR inquiries, applications, approvals and denials?

A. The Company is amenable to providing a written response to a customer whose EDR application was denied. Additionally, the Company can report to PURA annually on final accepted written applications, approvals or denials.

Q. Is it problematic to introduce a load retention special contract policy for customers on the EDR?

A. Yes. Mr. Dauphinais argues that a load retention policy addresses existing load that is at risk of being lost due to a competitive alternative or financial circumstances, while an EDR alone provides no benefit to an existing customer whose load is at risk but is not expanding. However, the principal purpose of the rate is to encourage new business activity or the expansion of existing businesses. Extending the discount to load that is already in the service territory could increase free-ridership without producing corresponding economic-development benefits.

While each require individualized analysis, load retention special contracts and the EDR are fundamentally different and should not be conflated. A load retention special contract involves an economic analysis and subsequent negotiation relative to existing service, infrastructure, rates and charges.

III. PROPOSED RATE 6

Q. Please summarize the comments and recommendations received from intervenors on the design of the heat pump rate.

A. Stakeholders were generally supportive of a heat pump rate being implemented by the Company, but recommended modifications on the level of the discount being offered, whether the transmission portion of the rate could be discounted, at what level to delineate energy consumption in Block 2, whether the rate should be opt-out or if customers should be automatically enrolled in the rate under certain conditions, and which customers should be eligible for the rate.

Ms. Whited recommends PURA reject the Company's proposed Rate 6 and instead adopt a cost-based, seasonal opt in TOU rate (including 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) that includes time-differentiated distribution, transmission, and supply charges, citing that Rate 6 does not effectively incentivize shifting electricity usage to off-peak periods.[26] Ms. Whited further recommends the rate 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.[27] Finally, Ms. Whited recommends removing the eligibility requirement for the heat

[26] Whited at 29-36.
[27] Whited at 35.

pump rate, specifically including customers that convert from natural gas and electric resistance heating customers.[28]

Mr. Velez, on behalf of CLF, recommends PURA reject the proposed Rate 6 and adopt his alternative rate schedule, Rate HP, for residential customers with heat pumps, that lowers the volumetric rates for distribution and transmission during the winter months (November through March) and would automatically enroll customers with heat pumps, regardless of prior heating system or timing of installation.[29] Separately, Mr. Velez claims the Company's R1 residential rates are overcharging heat pump customers for distribution and transmission costs, stating "[t]he Company could eliminate all of the entire overpayment — discount the rate all the way down to the floor — and customers newly installing heat pumps would still be paying their full incremental cost of service, still satisfying cost causation, without negatively affecting the bills of non-heat-pump customers."[30] Mr. Velez further claims that overcharging of heat pump customers under Rate 1 undermines Connecticut's building electrification policies.[31]

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28 Whited at 27-30.

29 Velez at 47-54, 81-92.

30 Velez at 7-28.

31 Velez at 32-46.

Q. Does the Company agree with Ms. Whited's recommendations for revising Rate 6 to be a seasonal TOU rate?

A. No. Ms. Whited dismisses the currently available time-of-day Rate 7 as an opt-in alternative, and abandons the proposed Rate 6 for a preferred, conceptual TOU rate design that she expounds upon, while overlooking the significant TOU price differentials available in the Rate 7 transmission, generation supply (standard service) and the public benefits rate components. Ms. Whited discusses future deployment of her proposed structure, if offered, on a mandatory (i.e., opt-out) basis, as a potential design to fulfill requirements of rate design proposal required by Public Act No. 25-173 (2025) (for filing by October 2027). The structures of the current Rate 7 are time-varying and cost-based and, indeed, provide an alternative if a time varying rate were of interest. For future consideration, such rate could be modified to incorporate a different time-of-day period, seasonality, and a different distribution pricing – the current rate has the same prices and is capable of setting different peak and off-peak distribution rates, per the stated tariff structure. The Company notes the importance of practical considerations that factor into any rate proposal, including those of Rate 6 or a modified Rate 7, both of which can be implemented with current systems and metering capabilities. Ms. Whited appears to ignore these considerations in her conceptual proposal.

While Rate 6 is designed to target incremental heating load, while avoiding overt discounts and cost shifting, Ms. Whited's proposed TOU rate is not an adoption or modification of Rate 6, but rather a switch to a different structure altogether. Although

she referred to the Rates Panel's direct testimony regarding review of enhanced TOU structures considered, no mention was made in either the TOU rate the Company reviewed or her proposed TOU rate of how this targeted objective (as represented through the tiered rate approach) was or could be addressed. In fact, the Company had examined potentially incorporating a tiered rate within a TOU structure. Following this examination, the Company determined that combining these two elements may be too complex and would be difficult for customer to understand. The desired objective could be met with the proposed Rate 6, and a viable, readily available alternative is available in Rate 7, both under current metering and billing system capabilities. Simplicity and customer understandability are important principles in designing a new rate offering. Rate 7 is a currently available rate that, even in its current form, reflects a balance of these and other rate design principles and the Company's proposed Rate 6 similarly reflects those principles.

We are proposing Rate 6 as an alternative, opt-in space heating rate that is cost-based (for all components of distribution service), provides a seasonal TOU characteristic, and provides a targeted incentive rate for new, incremental heat pump load. Its design is economically efficient, and simple to understand.

Rather than focusing on TOU prices for distribution, the Company achieves implicitly similar incentives to expand usage through its proposed block rate structure. Rate 6 lower distribution cost component in block 2 encourages adding load in winter months relative to the summer season. Residential space heating in the coldest months is

expected to take place mostly in the morning hours and overnight, and then more moderately throughout the day. There is not a meaningful cost-based justification for time-of-day differentiation in distribution charges in the winter. This is supported by the time-differentiation analysis of marginal distribution cost conducted by Ms. Nieto. As explained in Ms. Nieto's direct testimony, the distribution hourly loads result in almost zero probability of peak in the winter. Thus, marginal hourly distribution costs outside of the summer months June through September are essentially zero. It does not warrant time-differentiated volumetric charges from a distribution rate design perspective, even after considering moderate growth of heat pump load through the relevant six-year time frame for this initial rate design. Her analysis used as a reference ISO-NE's forecasted winter electrification growth for the area of Connecticut, through 2031. The upstream distribution summer peak loads will continue to drive investment needs during that period and beyond. This result is consistent with the Company's planning expectations.

Q. Why is it unnecessary for the heat pump rate to be revenue neutral with Rate 1?

A. It is unnecessary because there is no evidence that cost under-recovery will occur. A shift in revenue among components will occur under new rate design (e.g., higher customer charge, lower tier 1 and tier 2 rates). Usage below and up to the 700 kWh threshold remains at the revenue neutral tier 1 volumetric rate. Usage (both "base" and new, incremental usage above 700 kWh is priced at the discounted tier 2 price, which is above marginal cost and inclusive of the allocation of total revenue requirements

recovered in current rates). Individual customer contribution in a given month toward the breakeven for "revenue neutrality" that is measured on the basis of annual revenue and average annual rate is evaluated annually. Incremental load which includes the targeted winter heat pump usage is priced on a discounted basis and makes a positive contribution toward fixed cost recovery. Designing a revenue neutral rate on only usage prior to added load, and using the suggested alternative TOU rate structure, brings into question whether the same discounted rate proposed in Rate 6 is achieved. Additionally, that proposal is also predicated on not being able to specifically differentiate heat pump from any other incremental, new load, and for variations in usage, otherwise, would work in the same way as current rates with respect to variations in sales relative to design levels, reconciliation through revenue decoupling for distribution and in the reconciling mechanisms for other components of service.

Q. Does the Company agree that natural gas customers should be eligible for the heat pump rate?

A. No, the Company specifically excluded natural gas customers from the heat pump rate due to potential adverse financial consequences for customers. One of the principal considerations in developing the rate was to focus eligibility on customers who are most likely to achieve a favorable financial outcome from electrifying their heating load, which are delivered fuel customers. This targeting is intended to avoid encouraging conversions that may not reduce a customer's overall energy costs, which is more likely with gas conversions. While natural gas prices fluctuate, the Company does not have evidence that customers converting from natural gas heating to a heat

pump would necessarily be financially better off. Limiting or targeting eligibility is intended to direct the rate toward customers that are more likely to gain an affordability benefit by converting to electric air source heat pumps.

Q. Are there other funding mechanisms available to customers with natural gas heating that wish to install heat pumps?

A. Yes, customers who are not eligible for the proposed heat pump rate, Rate 6, may be eligible to receive support for adopting heat pumps through the applicable programs, including energy efficiency incentives through Energize CT and potentially other incentives programs, such as the New England Heat Pump Accelerator, which are currently available to customers regardless of their existing heating fuel.

Q. Should the discount on the distribution portion of the bill in the heat pump rate be larger?

A. When designing Rate 6, the Company set to ensure that the rate was set above the marginal cost to serve customer's new heat pump load so that the proposed rate is generally aligned with cost-causation principles. This helps ensure that participating customers cover the incremental costs associated with their usage rather than shifting those costs to nonparticipants.

For the rate to contribute meaningfully to affordability beyond the participating customers, incremental heat pump usage should recover more than marginal costs and make a reasonable contribution toward fixed system costs. That contribution can place downward pressure on the amount of fixed costs that must be recovered from other usage and customers.

The design recognizes that the system generally has available capacity to accommodate additional winter load. That capability is not unlimited or uniform across all locations and time periods, however, so the rate should remain aligned with system conditions and should not be interpreted as a finding that all incremental winter usage is relatively inexpensive to serve.

Q. Should the transmission portion of the rate be discounted as proposed by Mr. Velez?

A. No, the transmission portion of the winter rate should not be discounted. Mr. Velez proposes deeper transmission discounts as part of his proposed Rate HP.[32] Any differentiation between transmission and distribution rate components should reflect how the Company incurs the underlying costs. Aligning the rate design with the applicable cost drivers promotes a more accurate price signal and reduces the risk that the discount will encourage usage during periods that create additional costs for the Company.

This alignment is particularly important for transmission costs, which are influenced by how ISO-NE allocates costs based on monthly transmission system coincident peaks. The Company developed the transmission portion of the rate based on the class's monthly coincident peak demand and the rates charged to the Company for transmission service, consistent with ISO-NE's Regional Network Service ("RNS")-

[32] Velez at 81-83.

related transmission obligation. Departing from this cost allocation would be at cross-purposes of utilizing the heat pump rate to promote affordability.

Q. What is the most appropriate level for Block 2 to kick in and how should it be measured?

A. Using 700 kWh as the threshold is reasonable because it applies to a class-based benchmark rather than requiring an individualized calculation for every participating customer. As described in Exhibit CLP-Rates-1, lines 5-7, 700 kWh/mo. represents the average monthly usage of a customer without a heat pump. This approach is consistent with common ratemaking practice and makes the rate easier for customers and the Company to understand and administer.

Trying to determine individual thresholds for each customer by using separate heat pump meters, circuit-level energy monitors, or software as suggested by Mr. Velez is not feasible or scalable and is likely to be prohibitively expensive.[33] Any method for determining thresholds must be balanced against the time, cost, and resources needed to implement these solutions. The cost of these solutions should be considered in the context of affordability and whether incurring these additional costs helps or hinders the ultimate goal of reducing costs for customers.

[33] Velez at 79-80.

Q. Would low-income customers be disadvantaged due to this rate?

A. No, low-income customers would not be disadvantaged by this rate. Mr. Velez suggests that the proposed rate is inherently biased against low-income customers.[34] Although low-income customers may traditionally have lower usage and less of their heat pump usage would end up in Block 2, it is unlikely that low-income customers would opt for this rate in the first place because of the low-income five-tier rate. If a low-income customer installed heat pumps, they would likely qualify for one of the five tiers that are part of the low-income discount rate and receive a substantial discount on all usage, not just heat pump usage. And to the extent that all customers would benefit from the additional load from heat pumps as it contributed to recovery of fixed costs, low-income customers would similarly share in that benefit.

Q. Did intervenors propose an automatic enrollment option or opt-out structures?

A. Yes. Mr. Velez proposes automatic enrollments for customers as part of a heat pump rate.[35] Automatic enrollment warrants consideration because it could increase participation and reduce the risk that eligible customers fail to receive the rate. At the same time, the Company's experience through its other operating companies indicates that automatic enrollment can present data-matching, systems, customer-service, and resource challenges that may be time-consuming and costly to resolve. Although opt-

[34] Velez at 79.

[35] Velez at 93.

out designs can improve participation, PURA should balance that benefit against implementation feasibility and customer communication needs.

Q. Are there additional criticisms of the Company's Rate 6 design from Ms. Whited with which you disagree?

A. Ms. Whited voices concerns that the block 2 price may apply to uses other than heat pump load. The rate is indeed agnostic about which end use drives larger monthly electricity consumption. In practice, heat pump load will drive the customer monthly usage above the average winter consumption typical of non-electric customers, which is about 700 kW/month per month. The lower winter price applies to monthly usage above 700 kWh, which would effectively include added winter electrification loads. The Company decided to adopt a block energy rate structure which is effectively a seasonal rate, except that instead of a discounted rate to the entire usage of the customer in those winter months, with the proposed structure, only the customer usage in the second block faces a winter-specific price "discount." This lower price signal encourages usage. Even if other added winter usage benefits from the lower price, the rate incentivizes expansion of load and beneficial electrification takes place, even if the lower price affects more than just electric space heating.

Q. Ms. Nieto, you conducted a TOU cost analysis for distribution. What did your analysis reveal in regard to Ms. Whited's proposal of a TOU rate alternative?

A. As explained in my direct testimony and documented in the MCOS study, about 99.5 percent of the Company's probability of annual distribution peak currently falls in the

months of June through September.[36] This means that increases in load in the summer months drive investment expansion needs, and particularly within the period of 3pm to 8pm. There is not a meaningful hourly marginal cost difference across hours from a distribution-wide system perspective outside of the non-summer months, less than 1 percent of probability of peak. Time-differentiation of distribution costs would warrant a differentiated distribution price signal in the summer, if the focus was to adopt a fully cost-reflective rate. For a rate primarily focused on incentivizing beneficial building electrification growth, the higher growth potential is winter electric space heating, which does not require TOU rate differentiation in the winter. In other words, even though residential space heating usage is expected to peak in the morning hours, from 5am to 7am primarily and then again from 5pm to 10pm, these hours do not carry a meaningful probability of driving distribution investment needs over the next five to six years. The incremental supply costs and the incremental transmission costs do vary by time of day during the winter, in alignment with regional conditions, and this would justify winter TOU price differentiation for those components of service. Chart 1, below, shows the marginal hourly distribution cost by month based on my analysis to demonstrate this effect.

[36] Exhibit CLP-MCOS-1.

Table 1. Hourly marginal distribution substation and trunkline feeder cost, served at secondary, Weekdays, 2026$

Weekday System-Wide Average Hourly Marginal Cost by Month, with secondary losses ($/kW)

Hour	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	0.00011	0.00004	0.00002	0.00000	0.00000	0.00000	0.00000
8	0.00000	0.00000	0.00000	0.00000	0.00000	0.00067	0.00032	0.00012	0.00000	0.00000	0.00000	0.00000
9	0.00000	0.00000	0.00000	0.00000	0.00000	0.00146	0.00248	0.00091	0.00004	0.00000	0.00000	0.00000
10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00182	0.00588	0.00215	0.00061	0.00000	0.00000	0.00000
11	0.00000	0.00000	0.00000	0.00000	0.00000	0.00255	0.01074	0.00350	0.00112	0.00000	0.00000	0.00000
12	0.00000	0.00000	0.00000	0.00000	0.00000	0.00327	0.01666	0.00620	0.00196	0.00000	0.00000	0.00000
13	0.00000	0.00000	0.00000	0.00000	0.00000	0.00489	0.02180	0.01065	0.00326	0.00000	0.00000	0.00000
14	0.00000	0.00000	0.00000	0.00000	0.00004	0.00680	0.02846	0.01399	0.00399	0.00000	0.00000	0.00000
15	0.00000	0.00000	0.00000	0.00000	0.00008	0.00995	0.04348	0.01836	0.00502	0.00000	0.00000	0.00000
16	0.00000	0.00000	0.00000	0.00000	0.00013	0.01542	0.05325	0.02557	0.00612	0.00000	0.00000	0.00000
17	0.00000	0.00000	0.00000	0.00000	0.00023	0.01826	0.06240	0.02905	0.00626	0.00000	0.00000	0.00000
18	0.00000	0.00000	0.00000	0.00000	0.00004	0.01901	0.06363	0.02737	0.00603	0.00000	0.00000	0.00000
19	0.00000	0.00000	0.00000	0.00000	0.00000	0.01421	0.05278	0.02057	0.00444	0.00000	0.00000	0.00000
20	0.00000	0.00000	0.00000	0.00000	0.00000	0.00952	0.03467	0.01296	0.00329	0.00000	0.00000	0.00000
21	0.00000	0.00000	0.00000	0.00000	0.00000	0.00498	0.02281	0.00654	0.00157	0.00000	0.00000	0.00000
22	0.00000	0.00000	0.00000	0.00000	0.00000	0.00122	0.00685	0.00137	0.00016	0.00000	0.00000	0.00000
23	0.00000	0.00000	0.00000	0.00000	0.00000	0.00011	0.00065	0.00000	0.00000	0.00000	0.00000	0.00000
Daily Average	0.00000	0.00000	0.00000	0.00000	0.00002	0.00476	0.01779	0.00747	0.00183	0.00000	0.00000	0.00000

Q. Does this mean that the Company's proposed blocked rate structure, which does not differentiate the transmission component by time of day is inconsistent with sending efficient price signals based on marginal costs?

A. No. There are several adequate methods to introduce marginal cost differences that lead to more economically efficient usage decisions, including load expansion. Rate 6 provides seasonally-differentiated distribution price signals via a block rate structure that recognizes the lower marginal cost in winter. The benefit of a block structure is that it ensures recovery of the majority of existing costs of the system in the initial or baseline monthly usage, while the second winter block is lowered to reflect more closely the incremental costs in the winter. This helps encourage customer heat pump adoption and improve system utilization in winter months. In choosing between a

block rate and a non-block TOU structure, the Company has considered all factors; most importantly, customer acceptance and gradualism in implementation of rebalancing cost recovery across rate components. A TOU structure layered on a block rate structure tends to be very confusing to customers, as they do not know when the change in TOU price takes place, which is a function of cumulative usage up until the point of the decision in the month. Directionally, the Company's proposed Rate 6 is in alignment with the incremental cost pricing principles in two major ways; it departs from a year-round uniform energy rate, recognizing underlying seasonal marginal cost differences, and at the same time, increases the monthly customer charge relative to Rate 1 to recover in full the marginal customer costs. These costs would otherwise remain in the energy charges and contribute to cross-subsidies within the rate.

If the Company were to propose a rate without a block structure intended to encourage beneficial electrification, it would require shifting a much larger share of the class revenue target to the fixed component of the rate, so that the TOU per-kWh charges can be further lowered towards distribution and transmission marginal costs. A higher customer charge might make the rate unappealing to the average customer. This was a major factor that drove the Company not to propose an unblocked TOU rate at this stage. In the future, once more heat pumps have been adopted and it has its own class revenue target, it may be possible to consider offering an alternative rate TOU differentiation.

Q. Ms. Nieto, based on your expertise on marginal cost studies, and use for rate design, do you agree with Mr. Velez's proposal to reflect the time-differentiated marginal cost of transmission in the proposed Rate 6?

A. I do not find that Mr. Velez's proposed approach to compute the marginal regional bulk transmission cost is appropriate for purposes of rate design. Mr. Velez's application of the PoP method to the transmission annual loads to calculate a time-differentiated marginal cost to hours and months conceptually works well in estimating incremental transmission investment needed to meet incremental transmission load in any given hour. However, this ignores the fact that the Company serves electricity within ISO-NE region and as a distribution company is subject to payment of the ISO RNS transmission rate, which is calculated based on each month's coincident peak, as discussed earlier. The cost basis that is relevant for purposes of calculating the marginal transmission component should be based on what drives the payment that the Company makes to ISO-NE for transmission service as part of RNS tariff, not the "resource" marginal cost approach that would normally be helpful to consider value of peak-load shaving resources to the transmission system.

Mr. Velez conducted a probability of peak for bulk transmission loads, by replicating the method that Company witness Nieto developed for the Company's distribution hourly probability of peak. He then applies the results to propose a marginal regional transmission cost allocation to all hours on the transmission system, which falls on the summer coincident peak loads. Theis marginal transmission cost, corresponding to the regional pool transmission facilities ("PTF") that Mr. Velez uses is an estimate of the

avoided regional transmission cost of $69/kW-year, developed by Synapse in its 2024 Avoided Energy Supply Components study (Synapse 2024), inflated to 2026$. This avoided cost estimate is inconsistent with the *financial* marginal transmission cost that the Company faces as an unbundled utility, which is essentially the RNS rate, which does not change by month. To find alignment between transmission payments to ISO-NE, the applicable probability of peak should estimate how likely each hour of the month is to include the month's peak load and hourly factors would apply to the monthly RNS rate.

The Company seeks to balance a number of rate design objectives, including stability and reducing the risk of intra-class cross-subsidies. If customers using heat pumps for space heating were to drive up the month's transmission system peak, it would affect the corresponding ISO-NE payment. If they pay transmission charges set at the near-zero winter resource marginal transmission cost, the net revenue shortfall incurred by the Company would need to be recovered from all customers to keep the Company whole.

Q. Do you agree with Mr. Velez's definition of cross-subsidies based on charging for existing transmission and distribution fixed costs in the winter to limit cross-subsidies?

A. Not entirely. The definition of cross-subsidy should include not just recovery of incremental costs; each class should recover the corresponding marginal costs plus a share of the fixed costs of the system, to reconcile with the embedded cost allocated to the class in the ACOS study. Mr. Velez mentions that when fixed costs are recovered

through volumetric charges, customers with higher-than-average usage pay a greater share of those fixed costs, effectively subsidizing the customers with lower-than-average usage. However, for optional rates to be revenue-neutral, the class allocation of revenue requirement is based on overall Rate 1 charge. Over time, when the optional heat pump rate has customers on it, the revenue target will specifically be established for that optional rate, and it will likely have a lower per-kWh embedded cost allocation relative to Rate 1 which would retain lower usage customers.

Q. How do you respond to Mr. Velez's statement the Company has not reduced the kWh charge of the winter block 2 enough, and that the gap between charges and actual marginal T&D costs needs to be eliminated or meaningfully reduced?

A. Consistent with what was explained above, I agree that the gap between incremental per-kWh costs and incremental usage-related revenue should be reduced as much as possible, to get closer to an economic cost-reflective price signal. When there is no possibility of increasing the customer charge high enough to recover the residual share of class revenue target associated with fixed or sunk costs, the volumetric charges must continue to recover those costs. This would inevitably lead to higher-than-average usage customers, paying a higher share of the embedded costs. The Company has undertaken that step in the winter block 2 of Rate 6. Mr. Velez states that it should be lowered more, much closer to marginal unit system-wide distribution marginal and transmission resource marginal cost. Mr. Velez calculates the overpayment or gap by calculating the marginal T&D cost from the MCOS, allocated hourly, for the heat pump load usage and comparing these costs to the incremental T&D revenue collected under

the filed rates. This is a measure of the expected contribution of additional heat pump usage to the recovery of the costs of the existing system. Even if setting lower rates closer to time-differentiated per-kWh marginal costs, charges would still need to recover a share of the overall allocated distribution revenue requirement for past investments, which should not only be allocated to the summer months, but across all hours throughout the year.

Q. What is your take regarding Mr. Velez's statement that heat pump load does not increase the local facilities capacity required, and therefore block 2 charge should not include such a component?

A. Monthly marginal facilities costs, like transformers, primary lines and secondary cables used to connect the customer premise to the grid, are marginal at the time of connecting the customer, and therefore there is not strictly a direct correlation between ongoing changes in usage and incremental transformer capacity. An optimal rate structure recovers all facilities costs as a class-specific facilities charge outside of the volumetric charges, or in the monthly customer charge, but when this is not considered acceptable, it needs to be recovered in the kWh charges.

IV. ALLOCATED COST OF SERVICE STUDY

Q. Please summarize Ms. Whited's position and recommendations regarding the Company's ACOS.

A. Ms. Whited rejects the Company's Minimum System ("MS") study and proposes using a classification that relies on the Basic Customer method. Under this method, the only assets that are classified as customer-related are meters (FERC Account 370) and services (FERC Account 369), while any other distribution plant assets; including

conductors and conduits (Acc. 365 - 367), poles, towers and fixtures (Acc. 364), and line transformers (Acc. 368) are considered demand-related. In addition, Ms. Whited proposes in her direct testimony that should the Company decided to retain the MS method in this rate case, each class's non-coincident peak demand should be adjusted by the load-carrying capability of the minimum equipment, before allocating the demand-related cost portion of the assets. Ms. Whited also proposes a different classification of AMI meters, such that they are allocated partly to demand due to its value to provide services helpful for several distribution services.

Q. What are the conceptual shortcomings of the basic customer approach that Ms. Whited proposes for this rate case?

A. Simply put, the use of Basic Customer approach in an embedded cost allocation exercise is not fully cost-reflective. The demand allocation factors would allocate entire distribution plant, including upstream, primary and secondary local facilities, other than meters and services. This approach fails to consider the one-time impact of new customer connections, where the Company chooses equipment separately for circuits, poles and line transformers and relative differences in size across customer classes is not entirely driven by actual variations in their expected maximum demand. It is not uncommon that local facilities will be sized larger than strictly necessary to meet expected customer demands, due to a combination of economies of scale that warrants slightly larger standardized equipment sizes available to the Company.[37] An allocation

[37] This is particularly evident in the context of rural or semi-rural areas with predominance of single homes.

entirely made on the basis of demand using test year demands gives too much weight to existing demands. The Company field engineers, deciding on secondary plant and primary lines local to the customer, do not use today's demands or test-year class rather they consider connection standards involving: (a) how the equipment will be shared (customer numbers expected to be served downstream of those facilities long-term) and (b) those customers' demands during the life of those facilities. In other words, an allocation based entirely on class NCP which is test-year customer demands cannot capture the effects of economies of scale that drives plant size requirements and therefore allocating all lines or transformers fully on the basis of class demand is problematic and introduces a bias than the MS study may help reduce. This is, in Ms. Nieto's view, is the main reason why the MS method has stronger precedent in ACOS studies in the industry.

Q. Has the Minimum System classification approach been widely adopted in the country?

A. Yes, for ACOS studies, the Basic Customer price method is more scarcely adopted than the MS study, for distribution plant. Examples of U.S. utilities where a MS study is used include Alabama Power (AL), Georgia Power Company (GA), Central Hudson Electric & Gas (NY), Central Maine Power (ME), Choctawhatchee Electric Cooperative (FL), Con Edison (NY), Tampa Electric (FL), Connecticut Light & Power (CT), Duke Energy Progress (NC), Gulf Power (FL), Jackson County REMC (IN), Kentucky Utilities (KY), LG&E (KY), Madison Gas & Electric (WI), Mississippi Power (MS), Northern States Power (MN), and Carolina Power & Light (NC).

Q. Does NARUC cost allocation manual endorses the MS study?

A. Yes. The NARUC Electric Utility Cost Allocation Manual[38] recognizes the minimum system approach as one of the appropriate ACOS methods to determine classification of accounts 364 through 368. The NARUC Manual clearly states that each distribution plant account, 364 through 368, can be separately classified into a demand and customer component.[39] It also adds that: "*The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system*." The only instance where the NARUC's Manual mentions a method similar to the Basic Customer approach is in the context of the Marginal Cost methods, and this is irrelevant to the discussion of what to use in an ACOS study for customer costs.

Q. What impact would the basic customer price alternative have for the embedded cost allocations if adopted in lieu of the MS study?

A. Ms. Nieto tested the specific impact of an allocation of distribution plant entirely based on the ratio of residential class non-coincident peak demand (NCP) to total Class NCP as part of the interrogatory phase of this Docket, and the main implication of the Basic Customer method is that it shifts a larger share of plant costs to the commercial and industrial customers. This is expected, due to the relatively higher per-customer

[38] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, Jan 20, 1992.

[39] See NARUC Electric Utility Cost Allocation Manual, January 20, 1992, Table 6-1 in page 87 and page 90.

demand that commercial customers tend to have, but as explained above, it is a biased result as it misses the fact that larger demands tend to make better use of local transformer's economies of scale, i.e., they exhibit higher utilization of line transformer.

Q. What is your opinion regarding the use of modified demand allocation factors to exclude the minimum equipment size as proposed by Ms. Whited?

A. There is no doubt that the minimum equipment can serve a share of the load of the customers in each class, and therefore intuitively, one would find reasonable to account for that amount of equipment load serving capability in determining the net class NCP demands for allocation of the demand-related share of the plant. However, a concern is that this approach may add false precision because the class cost responsibility is not entirely proportional to class demand ratios due to utilization of minimum equipment once installed. The MS study does not capture all the nuances of customer density effect in investment decisions. The risk is that such adjustments may lead to mis-allocation of plant to the class with higher demand but also higher utilization per customer. For any distribution plant other than substation and trunkline primary feeders, investment decisions are largely driven by the numbers of customers served and the sizes of the specific transformers and conductors are largely standardized. The MS is a reasonable classification method by designating a minimum portion of the equipment (in the case of line transformers, this is represented by the smaller transformer installed today, which is 10 kVA) as customer-related, covering a minimum load that tends to be only a share of the customer design demand. The

transformer plant required per residential customer is actually larger than the average residential customer's actual demand. The cost per kVA may also be smaller in any case for a commercial-serving transformer, given the economies of scale of larger transformers.

Q. Do you agree with Ms. Whited's proposed reclassification of AMI meters based on customer and demand to be more cost-reflective?

A. AMI meters do serve an important role in distribution operations, remote disconnects, and support of demand response programs and tariffs. However, given that AMI meters are practically the new standard in today's modern utility, and the fact that there is no direct correlation between demand growth and AMI meter need, the cost driver should be the customer additions as in the current ACOS study filed by the Company.

V. ADVANCED METERING INFRASTRUCTURE

Q. Did the Rates Panel submit testimony as part of the Company's initial filing regarding the proposed Advanced Metering Infrastructure ("AMI") project.

A. No. As part of the Company's initial filing, Company witnesses Jared Lawrence and Douglas Horton provided testimony regarding the technology and implementation of advanced metering infrastructure, as well as regarding a new cost recovery framework for technology and implementation costs. However, Ms. Whited, on behalf of OCC, recommends that, as part of the AMI implementation, PURA 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.[40] Ms. Whited argues that the Company's demand allocation method for distribution system infrastructure does not reflect localized variance in cost causation.[41]

Further, Mr. Dauphinais on behalf of CIEC, recommends, to the extent PURA allows CL&P to recover AMI costs, whether through the PBMRP or another mechanism, that PURA reject CL&P's proposal to allocate those costs on the basis of class distribution revenue and instead, AMI costs should be separately identified and allocated on a cost basis by using the weighted meter cost allocator used in CL&P's ACOS to allocate Account 370 meter plant.[42] Mr. Dauphinais argues that allocating AMI costs on the basis of class distribution revenue shifts AMI costs to classes whose share of distribution revenue is large relative to the number and cost of their meters, which are primarily the larger commercial and industrial classes.[43]

Mr. Dauphinais further recommends that PURA direct CL&P to use the same cost-based allocation for the deferred AMI-related O&M expense and stranded AMR meter costs when it seeks recovery of those costs, unless CL&P demonstrates that a different cost-based method is more appropriate.[44]

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40 Whited at 8, 20-22.

41 Id.

42 Dauphinais at 29-31.

43 Id.

44 Id.

Q. Do you agree with Mr. Dauphinais's recommendations regarding allocation of AMI costs?

A. For purposes of cost of service analysis, 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. While we agree with Mr. Dauphinais in that the classification of costs as customer-related is appropriate, we disagree not necessarily on what the cost-of-service study produces, but that the proposed allocation of such costs and their recovery through the PBMRP, or otherwise as determined by PURA, is appropriate. Please see also the following rebuttal to Ms. Whited's recommendation.

Q. Do you agree with Ms. Whited's recommendation regarding the AMI implementation?

A. Similarly, for purposes of cost-of-service analysis, the Company expects AMI meter costs to be properly classified as customer-related costs. The results of the allocated cost of service study serve as a guide to inform the allocation of costs and design of rates. Additionally, there are specific ratemaking requirements and methodologies that perhaps Ms. Whited is not aware of which derive key data from properly classified customer costs in the cost-of-service study. For example, the MMRC calculation for

determining the residential Rate 1 customer charge, designated per statute and regulation, requires the use of the cost of a meter, among other customer related costs, in its development. With regard to class cost of service (i.e., revenue) allocation, PURA determines the ultimate allocation of revenue among classes, along with the portion of such revenue attributable to customer charges and to demand charges (which are assimilated through volumetric or demand charges, depending on the class). These allocations do not match precisely to the cost-of-service study and further, the portion of customer and demand revenue within each class do not match precisely the respective customer and demand allocations of costs within the allocated cost-of-service study.

Therefore, regarding AMI implementation, the Company disagrees with Ms. Whited's recommendation. The Company's expectation is that AMI costs would properly be classified as customer costs, and 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. The proposed allocation of AMI implementation costs to each class through the PBMRP would be based on such authorized distribution rate revenue, which notably includes both customer and demand components.

VI. OTHER RATE DESIGN

Q. Please describe the testimony regarding rate design submitted by Mr. Eben Perkins on behalf of the University of Connecticut.

A. Mr. Perkins advocates for a Connecticut CPT rate, relying on prior implementation of a CPT at other utilities as a basis for carrying forward a similar proposal into this rate case.[45] It is unclear whether he is a proposing a temporary or more permanent proposed rate design. He also advocates for a change in the rate design itself without specifying whether he is advocating for both such rate redesign and the option to participate in the new rate, regardless of whether a customer ends up paying more or less due to their success or failure to reduce load at the one hour of the month. Most importantly, Mr. Perkins does not consider what costs may be shifted to other customers as a result.

The "fixed costs" that he discussed are a reminder that, in the context of the distribution and transmission rates he is seeking to change, the rates we design are for charges to customers for the recovery of fixed costs of the systems they utilize.[46] A change in either distribution or transmission rate structures, especially for the rate classes Mr. Perkins references, would directly implicate the prospect of cost shifting, both intraclass and interclass, among the smaller customers that the Company provides service to. For transmission services, the potential for cost shifting translates to other utilities throughout ISO-NE, and may be shifting costs to CL&P as a result of CPT

[45] Perkins at 31-38.

[46] Perkins at 29-30.

customers in the other jurisdictions referenced by Mr. Perkins.[47] This cost shifting would occur in terms of both cost allocation and the setting of rates for transmission service. A reduction in transmission service load from, for example, a large C&I customer, for one hour of a month would reduce the revenue for service that they take, causing an under-recovery of revenue expected from the rate being charged. Under a CTP rate, a customer could "chase" the hour of the ISO-NE transmission system peak demand for RNS service in order to reduce their billing demand and thereby bypass the obligation to pay for service they receive – shifting those costs to other, smaller customers. It may be likely that such customer uses the transmission system in all hours of the month but that one hour. Although their load in all other hours may be equal to or greater than that of the peak hour load, they may pay little or nothing for transmission service despite taking transmission service in all other hours. Transmission owners construct, maintain and operate the transmission grid to provide firm, reliable service to that customer. The costs of that system do not change – they are fixed. The fixed cost of the transmission grid spread over a smaller load due to the avoidance of demand for one hour will, all else being equal, increase transmission service rates to all customers.

[47] Id. at 19-20.

Q. How much cost shifting and what additional insights can we gain regarding existing CPT rates and participation?

A. Given the prevalence of the CPT rate at other utilities advertised by Mr. Perkins, it would be informative to know the extent of avoided transmission charges by customers participating in this type of rate mechanism, and magnitude and extent of service they receive for all other hours. It would also be informative to understand the impacts of cost shifting due strictly to changes in rate design, such as that contemplated by Perkins for CL&P (e.g., due to a change in peak hours; the change in billing units during which transmission rates apply). The answers to these and many other questions would be important to explore in an investigation or consideration for developing such a rate mechanism.

While Mr. Perkins is calling for an update to transmission rate design and time-of-use periods, he is centrally focused on a retail CPT rate mechanism. Charges for transmission service may be reduced for individual customers; however, the complexity in their development and basis should be unwrapped and understood. It is important to note, unlike the billing of demand charges that occur at the transmission service level and as allocated down to rate classes and designed into rates, the underlying costs of transmission service itself may not be reflected in these allocations or design. The impact of single hour load reduction and avoided charges by an individual retail customer translates to an increase in transmission rates and a shift in who pays for that customer's transmission service. This concern prompts several questions that need to be addressed regarding the proposed CPT rate. For example, to

what extent should a customer not have to pay for the system they use? For the rate designs advocated, what are the underlying costs, structures and mechanisms that support potential rate designs being advocated? Should transmission service rates be revised from the current single monthly peak demand approach? Should a hybrid or other approach applied in other regulatory jurisdictions be considered for development of wholesale level transmission level service? The Company recommends that PURA not simply adopt the proposals being advanced or direct the Company to develop them without further examination. Rather, PURA should first seek answers to these and other relevant questions and proceed deliberately, ensuring that any resulting directives are informed by a thorough understanding of the issues and their potential implications.

Q. Do you agree with Mr. Perkins's recommendation that the Company examine time-of-day and seasonal differentiation of distribution demand charges for large customers and propose a tariff supported by class-specific evidence?

A. No, we do not. Mr. Perkins has clearly misunderstood the time-of-day provisions of various CL&P rate schedules. The plain meaning of "prevailing time" is for residential customers to simply be aware that the peak period is the same hours, whenever they look at a clock. For non-residential customers, it is simply a matter of understanding that peak hours during EST are different than the peak hours under DST. This was deliberately developed through stakeholder collaboration and in response to customers' needs, as ultimately authorized by PURA in the Company's previous distribution rate cases.

Although Mr. Perkins is critical of the consultant recommendations, it is important to note that the marginal cost study in this case was commissioned to evaluate and provide initial insight into the marginal costs of the Company's distribution system. It is the first study of this type that has been conducted for CL&P since pre-restructuring. We have gained new, current insight from this study, and have been able to apply the results in updating current rate designs under current TOU structures, including where distribution and transmission demand charges apply (i.e., rate differentials the Company's EV TOU rates), and in development of new rate design proposals (e.g., marginal, volumetric marginal costs for Rate 6). This study has also been instrumental in examining efficient pricing by better aligning marginal costs for fixed customer or local facilities costs. Mr. Perkins has blended conclusions or implications from the distribution marginal cost study in arguments related to both distribution and transmission. This study and potential future versions of this study may be relied upon to inform future Distribution rate design; however, the Company cautions the use or application of results or conclusions in transmission rate design.

Q. Are Mr. Perkins's recommendations or concerns regarding rate design more appropriately addressed in other proceedings or through other initiatives?

A. Yes. First, the Company's proposed AMI deployment plan is intended to support advanced rate design, including structures like those Mr. Perkins contemplates. Second, the Company must submit proposed TOU rate designs by October 1, 2027, under Public Act No. 25-173 (2025), and those designs will be informed by metering and billing capabilities. Third, the Company expected to participate in a working group

from March 2027 through December 2027 regarding front-of-the-meter storage rate design and that may address some of the issues Mr. Perkins raises. Fourth, the ongoing investigation into rate designs for MHD EV facilities is expected to address many of the same issues, including the distribution demand ratchet and more complex time-varying rates.

VII. PBMRP Tariff

Q. Please describe the tariff changes being submitted to address the claims of various parties and intervenors in their rebuttal testimony.

A. As discussed in the Company's Leadership Panel rebuttal testimony (see Exhibit CLP-LEADERSHIP-REBUTTAL-1), the Company is herein submitting a redlined version of the PBMRP tariff (EXHIBIT CLP-RATES-REBUTTAL-2). The purpose of this exhibit is to assist in responding to the claims of the various parties and intervenors. The original version of the PRMRP tariff was submitted by the Company in its Application, in Exhibit CLP-RATES-3.

The Company's initial filing in this proceeding originally anticipated that rate year capital would be reflected in base rates effective July 1, 2027, and that the first F Factor would take place a year later on July 1, 2028. In order to both conform to the design contemplated by the CT Bar, and in order to assure that plant additions included in base rates as a result of this proceeding have sufficient time for review in this proceeding, the Company has modified the PBMRP Tariff to reflect the fact that the F Factor would go into effect on July 1, 2027, commensurate with new base rates in this proceeding and would capture the prospective revenue requirement on plant additions after the base

rate cutoff, subject to the same review reconciliation procedures which are components of the Company's F Factor proposal. This proposal alleviates the need for PURA to consider capital additions in the period January 1, 2027, and forward, other than in terms of the F Factor.1

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, subject to reserving the Company's right to respond to additional issues raised in discovery or at hearings.