Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Exhibit CLP-RATES-3 which indicates that for intermediate and large commercial customer classes (i.e., Rates 55, 56, 57, and 58), Eversource's on-peak hours currently include 12 P.M. to 8 P.M. on weekdays during Eastern Standard Time and 1 P.M. to 9 P.M. on weekdays during Daylight Savings Time. When did Eversource last modify its on-peak hours for the Company's intermediate and large commercial customer classes? Please identify separately the most recent modification, if any, for the purpose of assessing (i) distribution demand charges and (ii) production/transmission demand charges.

Response:

The on-peak hours for the Company's intermediate and large commercial customer classes (i.e., Rates 55, 56, 57, and 58) were last modified following PURA's final decision dated December 21, 2006 in Docket No. 05-10-03 Application of The Connecticut Light and Power Company to Implement Time Of Use, Interruptible or Load Response, and Seasonal Rates**.** Prior to this docket, the Company's on-peak period extended from 7 A.M. until 11 P.M., (a 16-hour period) weekdays, under these customer class tariffs. The shift at this time was to provide large C&I customers with a stronger financial incentive and a more realistic opportunity to shift consumption to off-peak periods.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Exhibit CLP-MCOS-1, pp. 17-18 which states "[t]here is a significantly lower probability of peak from noon to 3 P.M. relative to hours 3 P.M. to 8 P.M., which recognizes the impact of solar PV penetration in early to mid-afternoon. This suggests that a modification to introduce a shorter peak period that starts at 4 P.M. and ends at 9 P.M. would increase cost-reflectiveness of the distribution rate."

a. Please explain why the finding that the current on-peak period does not align with the hours of highest on-peak probability is not reflected in the on-peak hours proposed for Rates 55, 56, 57, and 58.
b. If the on-peak billing window used to determine demand distribution and transmission charges does not correspond to the hours in which Eversource's monthly coincident peak is most likely to occur, please explain how the proposed rate design is consistent with the principles of fairness and cost causation.

Response:

a. The on-peak period does not apply to Distribution rates for these rate classes. Furthermore, the current on-peak period that applies to other rate components is established in accordance with rates proposed and approved by PURA. The Company did not propose a change to the on-peak hours for these rate classes.

b. The on-peak period is irrelevant for distribution rates of these rate classes. For transmission rates, the allocation of costs and design of rates for these rate classes corresponds with the monthly coincident peak of these classes.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Has the development of distributed solar generation in Connecticut over the last 10 years changed load profiles on Eversource's transmission and distribution system? If yes, please explain how those changes are reflected in the on-peak hours proposed for rates 55, 56, 57, and 58 for the purposes of assessing distribution demand charges and transmission charges.

Response:

The question is irrelevant for these rate classes, whose Distribution rates are not time differentiated. Transmission cost allocation reflects the coincidence of these classes' diversified demand with the Company's corresponding monthly peaks associated with transmission service. This allocation and the associated rate design for the on-peak period established in current rates is predicated on demand allocators from the Company's previous rate case and is planned to be updated based on demand allocators derived from the Test Year, and Rate Year billing determinants from this docket as part of the next transmission rate setting following conclusion of this case.

Date Filed: October 02, 2026

Witness: Lavelle A. Freeman and Juan F. Martinez
Request from: UCONN

Question:

(Rate Design & Tariff Structure) For each distribution substation in Eversource's Connecticut service territory please identify the peak load (measured in MW) and timestamp (date, hour ending) of the maximum 15-minute load measured at the substation in each month of 2025.

Response:

Please refer to UCONN-004, Attachment 1. The attachment contains 12 peak load values for each Eversource bulk substation in Connecticut listed in MW's. The attachment also includes the associate substation's timestamp for that peak load value for each month of 2025.

Date Filed: October 02, 2026

Witness: Lavelle A. Freeman, Gerhard Walker, Juan F. Martinez, Justin M. Pelkowski and Jingyuan Dong
Request from: UCONN

Question:

(Rate Design & Tariff Structure) For each month in calendar year 2023, calendar year 2024, and calendar year 2025, please identify the actual and projected peak load hour measured on Eversource's transmission system (as reported to ISO New England for Regional Network Service load purposes), including date, hour ending, and Eversource's average 60-minute MW load measured during the Company's monthly peak load hour.

Response:

Please refer to UCONN-5, Attachment 1, for the actual, historical peak load data.

Date Filed: October 02, 2026

Witness: Lavelle A. Freeman, Gerhard Walker, Juan F. Martinez, Justin M. Pelkowski, Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) For each monthly peak load hour identified in questions UCONN-8 and UCONN-9, please provide Eversource's estimate of the contribution of intermediate and large commercial customers (Rates 55, 56, 57, and 58) to the total load during that hour.

Response:

Please refer to CIEC-020, Attachment 1, for the requested information.

Date Filed: October 05, 2026

Witness: Warren R. Boutin and Andrew C. Belden
Request from: UCONN

Question:

(Rate Design & Tariff Structure) What was the total installed capacity (measured in alternating current megawatts) of behind-the-meter solar photovoltaic generation in Eversource's Connecticut service territory as of year-end 2010, as of year-end 2015, as of year-end 2020, and as of year-end 2025?

a. For each period, what percentage of behind-the-meter solar capacity was installed by intermediate commercial customers (Rates 55 and 56)?
b. For each period, what percentage was installed by large commercial customers (Rates 57 and 58)?

Response:

Power Clerk tracks the installed capacity for the behind the meter solar generation. The customer billing rate needed to determine the percentages installed by medium to large commercial customer is not available in Power Clerk. Thus, questions a. and b. cannot be answered. Please refer to the table below which represents a running total of behind-the-meter solar generation.

Year	Running Total PV Generation MW)
2010	21.31
2015	144.29
2020	451.73
2025	979.14

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Exhibit CLP-RATES-1 at p. 10. The MHD-EV class is a new and separate rate class that started in 2025 and is constructed very similarly to Eversource's EV-Large rate class.

a. Please explain how Eversource constructed the distribution component of Rate EV-MHD and Rate EV-Large.
b. Please explain how Eversource constructed the transmission component of Rate EV-MHD and Rate EV-Large.
c. Please explain why the distribution demand charge included in Rate EV-MHD and in Rate EV-Large varies based on a customer's load factor.
d. Please explain why the transmission demand charge included in Rate EV-MHD and in Rate EV-Large varies based on a customer's load factor.

Response:

a. The distribution component of Rate EV-Large is based on Rate 56. First, an average distribution rate per kWh is calculated by dividing the Rate 56 Distribution Demand Charge revenue by Rate 56 billed sales. Once this average distribution rate is established, it is converted into an on and off-peak rate using an on-peak differential derived from the Marginal Cost Study (MCOS) and on and off-peak sales splits for Rate 56. This calculation provides the on and off-peak Distribution per kWh rate for Tier 1 of Rate EV-Large. Tier 1 has no Distribution Demand Charge. To determine the Distribution Demand Charge of Tier 2 through Tier 8, the Rate 56 Distribution Demand Charge is divided into seven (7) equal shares, with each Tier accumulating one share as it moves towards Tier 8 (full Rate 56 pricing). The reverse process is used for the on and off-peak Distribution per kWh charges. Rate EV-MHD uses the same distribution rates as Rate EV-Large for both demand and per kWh. The only difference is the load factor ranges for each of the eight (8) tiers. Please refer to UCONN-8, Attachment 1, for the calculations supporting this explanation.

b. The transmission component of Rate EV-Large is based on Rate 56. First, an average transmission rate per kWh is calculated by dividing the Rate 56 Transmission Demand Charge revenue by Rate 56 billed sales. Once this average transmission rate is established, it is converted into an on and off-peak rate using an on-peak differential derived from the Marginal Cost Study (MCOS) and on and off-peak sales splits for Rate 56. This calculation provides

the on and off-peak Transmission per kWh rate for Tier 1 of Rate EV-Large. Tier 1 has no Transmission Demand Charge. To determine the Transmission Demand Charge of Tier 2 through Tier 8, the Rate 56 Transmission Demand Charge is divided into seven (7) equal shares, with each Tier accumulating one share as it moves towards Tier 8 (full Rate 56 pricing). The reverse process is used for the on and off-peak Transmission per kWh charges. Rate EV-MHD uses the same transmission rates as Rate EV-Large for both demand and per kWh. The only difference is the load factor ranges for each of the eight (8) tiers. The Transmission rates will be updated using approved rate case determinants during the subsequent RAM cycle following the Final Decision of this proceeding. Please refer to UCONN-8, Attachment 1, for the calculations supporting this explanation.

c. The distribution demand charge included in Rate EV-MHD and in Rate EV-Large varies based on a customer's load factor due to the requirements of subpart (c) in the referenced Order No. 12, whereby the Company shall file, no later than August 1, 2022, for PURA review and approval, proposed design documents that include a proposed tariff specifically for separately metered DCFCs and networked Level 2 EVSEs serving light-duty fleets, as directed in Section V.C.2.c., which states:

> The Authority finds that a more robust and permanent demand charge mitigation solution that reflects an appropriate allocation of distribution system costs is necessary to support the sustained growth of the EVSE industry in the State. The Authority will further consider a more sustainable solution during the 2022 Annual Review. Accordingly, the Authority will require the EDCs to propose a tariff specifically for separately metered DCFCs and networked Level 2 EVSEs serving light-duty fleets, to be submitted to the Authority no later than August 1, 2022. The tariff shall include a fixed monthly charge, on-peak and off-peak kWh distribution charges that are higher when a charging station's load factor is low (e.g., utilization of <5%) and decrease at established increments as charging station utilization increases, and kW distribution and transmission demand charges that are lower when a charging station's load factor is low and increase at established increments as charging station utilization increases. To minimize program costs, any revenues from billed sales that exceed the established revenue requirements used to design the tariff over the useful life of the EVSE shall be tracked by the EDCs and credited back to ratepayers through a rider or other rate reconciliation mechanism. The tariff shall be offered to all electric utility customers with separately metered DCFCs and light-duty fleets with installations of four or more networked Level 2 chargers that are enrolled in a managed charging program.

d. The transmission demand charge included in Rate EV-MHD and in Rate EV-Large varies based on a customer's load factor due to the same requirements as mentioned in subpart (c) above.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Exhibit CLP-RATES-3. Eversource assesses distribution demand charges and transmission demand charges to intermediate and large commercial customers using billing units based on kilovolt-amperes ("kVA").

a. Please explain why Eversource believes it is appropriate to continue assessing such charges in kVA rather than using kilowatts ("kW").
b. Please explain the bill impact of converting from kVA to kW billing units on Rates 55, 56, 57, and 58 customers. Please provide detailed analysis.

Response:

a. The use of kVA is designed to capture and present total delivery power requirements and incentivize efficient utilization of delivery facilities, as measured by power factor at their point of service. From the inception of kVA metering and billing customers have responded to this structure and the price signals afforded by kVA demand billing and achieved numerous benefits as a result of lowering demand charges, particularly through installing and maintaining power factor management and correction equipment at their facilities often with a relatively short payback. This kVA structure continues to provide an accurate and transparent means of informing each customer of their demand while achieving efficient utilization of the grid for power delivered to their facilities. The continued utilization of kVA demand ensures customers retain an accurate measure of their total power delivery requirements. The kVA demand directly translates to the current (amperes) flowing through the power system unlike kW. This current is what drives utilization of the system and impacts ratings of every piece of equipment which are always in amperes or kVA, not kW as it does not correlate directly to amperes flowing. Its use is an integral and valuable part of the demand-based rate structures that customers can rely and act on when making decisions about their electric service.

b. From a rate design and policy perspective, converting to kW from kVA billing runs counter to the intent and the benefits achieved through the establishment of kVA metering and billing. The factors in the Company's tariff for converting rates from a per kVA to a per kW basis is reserved and applies only to those customers for whom, at the time the kVA rate was established, kVA metering was not available. These factors are class average values that only apply on this limited basis. The application of kVA metering and billing was phased in over time, first for rates 57 and 58 customers and later for Rate 55 and 56

customers. Since its inception, customers have responded to kVA rates and invested in equipment that improved efficiency and lowered their total power delivery requirements and charges for electric service. These benefits have been realized in both distribution and time-varying transmission rates and charges. Reverting to a kW rate would remove this price signal and be regressive. A conversion using class average power factors would produce inaccurate and inappropriate kW values, particularly when compared with the actual power factors and resulting kW demand.

For illustrative purposes, the company has provided a calculation of kW demand values associated derived from billed kVA and assumed class average power factors. Please see these calculations, by rate class and demand charge type, in UCONN-09 Attachment 1. To reiterate, these calculations are strictly for illustrative purposes and are not a proposal for rate design for any of these rate classes. A conversion of this type will produce a higher unit rate and lower, theoretical kW billing units. While the higher rate would be retained, the actual bill impact compared with this illustration will vary, depending upon customers' actual power factors and thereby actual kW demand.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Exhibit CLP-RATES-1 at p. 34 which states that by providing a reduced rate for incremental usage related to heat pumps, the Company believes it can help drive adoption of heat pump technology and achieve better system utilization during winter months. Eversource goes on to state that this will help drive better system utilization as the Company is currently a summer peak system.

a. Does Eversource believe that this outcome can also be achieved if intermediate and large commercial customers consume additional electricity in the winter months?
b. Does Eversource believe that DER adoption and operation by intermediate and large commercial customers can improve system utilization if a DER is operated to reduce a customer's grid demand during hours of peak demand on Eversource's transmission and distribution system?
c. Please explain why Eversource has not proposed seasonal differentiation in its distribution rates for intermediate and large commercial customers on Rates 55, 56, 57, or 58.

Response:

a. The referenced outcome is attributable to incremental monthly kWh usage from heat pump adoption for space heating during winter months. The incremental usage characteristics were derived from the difference between the residential non-space heating class, as a baseline, and residential electric space heating. The Company did not conduct a comparison assuming greater usage in the winter season by intermediate or large commercial customers.

b. From a distribution system operator perspective, DER adoption and operation by an intermediate or large commercial customer that reduces the respective customer's grid demand during hours of peak demand does not help the system, unless the system is relieved of any capacity requirements for that respective customer during the peak – meaning that the customer would have no back-up source of power on peak. The distribution system is constructed to meet the requirements of localized peak demands and if one or more customers is able to take their load off-line, it benefits that customer. It benefits other customers, only if the Company is actually able to avoid the need for capacity on the system, which can only occur if the customer benefitting from DER is willing to relieve the system of an obligation to provide firm service upon demand for the single

customer. From an ISO-NE perspective, reduced demand is a benefit in a supply-constrained market.

DERs have, to some extent, the ability to improve grid utilization. There are, however, significant limitations to such statements that cannot be ignored.

- DERs, if not properly and centrally managed, can decrease grid utilization as shifting of load can very easily create new peaks. Given that the infrastructure will be needed or is already installed (unless customers actually agree to forgo even the ability to rely on the grid), costs remain present and will then be allocated to other customers creating a downward arms race leaving the less well equipped customers holding the costs and creating an equitably questionable environment of cost shifting.
- All equipment ratings on the Company's system are developed under the technical assumptions of lower load periods to allow equipment cool down. If utilization is driven up, such ratings would need to be recalculated to lower set points as equipment no longer is afforded cool down (e.g. if load becomes flatter) which will negatively impact the system's ability to serve load and potentially offset benefits from higher utilization.

c. The Company is at an early stage in its evaluation of time-varying load, cost of service and other characteristics associated with the many different components of the distribution system and facilities involved in provided distribution service. The marginal distribution cost analysis conducted and submitted as part of the Company's rate application is the first such study of this nature performed since restructuring. The insights from this and further analysis of this type are expected to provide new insights for future rate design, including more advanced structures that may be time-of-use (TOU) based pricing. A seasonal distribution rate structure represents one subset of future distribution rate structures that could be considered.

Although the Company has developed and currently offers time-of-day rates for certain components of rates, its plan is to develop and propose more advanced rate design, including time-varying rate structures that will be enabled by AMI metering. More extensive and granular usage and cost of service data, and the ability to implement more advanced rate design options, including seasonal rates if appropriate, is anticipated to be available from the deployment of AMI meters. Meanwhile, early approaches to TOU rate design using the marginal cost of service study as applied to current rate structures have been applied in the Company's proposed updates to its TOU EV rates, and in proposed Rate 6.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Exhibit CLP-RATES-1 at p. 37. Consistent with established regulatory principles, Rate 6 is "designed first and foremost to benefit ratepayers through improved system economics and affordability, while also supporting broader climate change objectives." Does Eversource agree that DER adoption and operation by its intermediate and large commercial customers to reduce a customer's grid demand during hours of peak demand on Eversource's transmission and distribution system can benefit other ratepayers through improved system economics and affordability?

Response:

No, not necessarily. As a first matter, the reason that the Company's proposed heat pump rate improves system economics and affordability for the residential customer, is that the rate is designed to promote the use of the system during the winter months when there is relatively lower consumption on the electric system. This proposition does not simply translate to the proposition that DER adoption reducing a customer's grid demand on peak will equally benefit other customers with "improved system economics and affordability."

From a distribution system operator perspective, DER adoption and operation by an intermediate or large commercial customer that reduces the respective customer's grid demand during hours of peak demand does not help the system, unless the system is relieved of any capacity requirements for that respective customer during the peak – meaning that the customer would have no back-up source of power on peak. The distribution system is constructed to meet the requirements of localized peak demands and if one or more customers is able to take their load off-line, it benefits that customer. It benefits other customers, only if the Company is actually able to avoid the need for capacity on the system, which can only occur if the customer benefiting from DER is willing to relieve the system of an obligation to provide firm service upon demand for the single customer.

From an ISO-NE perspective, reduced demand is a benefit in a supply-constrained market. However, from a distribution system perspective, capacity requirements are not relieved when individual customers take advantage of DER to improve their own economic proposition so long as there is an expectation that the distribution system can support all loads with or without the DER alternatives for specific customers.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Connecticut General Statute § 16-19e which requires that rates be set in accordance with "the prudent management of the natural environment." Does Eversource agree that DER adoption and operation by its intermediate and large commercial customers to reduce a customer's grid demand during hours of peak demand on Eversource's transmission and distribution system supports prudent management of the natural environment including by reducing total emissions of greenhouse gases?

Response:

Conn. Gen. Stat. § 16-19e does not require PURA to set distribution rates in accordance with the "prudent management of the natural environment." The actual language of the statute requires that:

> In the exercise of its powers under the provisions of this title, the Public Utilities Regulatory Authority shall examine and regulate the transfer of existing assets and franchises, the expansion of the plant and equipment of existing public service companies, the operations and internal workings of public service companies and the establishment of the level and structure of rates in accordance with the following principles:
>
> (3) [t]hat the authority and all public service companies shall perform all of their respective public responsibilities with economy, efficiency and care for public safety and energy security, ***and so as to promote economic development within the state with consideration for*** energy and water conservation, energy efficiency and the development and utilization of renewable sources of energy ***and for the prudent management of the natural environment***.

Conn. Gen. Stat. § 16-19e(a)(3) (emphasis added).

Thus, the "principle" that PURA must incorporate into its rate setting exercise as a result of Conn. Gen. Stat. § 16-19e(a)(3) is that it must seek to promote *economic development* within the state with consideration of … the prudent management of the natural environment.

That said, Eversource agrees that – from an ISO-NE perspective -- DER adoption and operation by its intermediate and large commercial customers that reduces grid demand during hours of peak demand may help to reduce total emissions of greenhouse gases in a constrained wholesale market burning fuel oil to make ends meet.

Date Filed: October 02, 2026

Witness: Andrew C. Belden, Stephen J. Bruno, Edward A. Davis and Kimberly Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Please provide copies of all workpapers, calculations, and analysis Eversource used in evaluating how current rate design impacts customers' ability to reduce their grid demand during monthly peak load hours or on-peak periods through active load management or through the adoption and operation of DER.

Response:

Please refer to the Company's response to UCONN-18[i]. The fundamental exercise in this rate proceeding is for Eversource to present the cost of service required to provide customers with an essential service that must be delivered with a high degree of reliability at an affordable price for all customers. In that context, there are two fundamental realities that apply: (1) the business of delivering safe and reliable power to customers is an infrastructure-centric endeavor; and (2) the costs of building, maintaining, reinforcing and upgrading that infrastructure are borne across a wide range of customer classes that make differing use of the system and that have differing methods and capabilities to pay for that use.

The rates that the Company has proposed in this proceeding were developed using the Company's actual costs incurred and established methods to allocate those costs across the customer base in accordance with the use of the system. Utility rates are, by definition, designed to be collectively applied across a broad disparity of customers, including residential customers. In that context, the Company does not propose to set rates in a manner that would allow one customer segment to shed cost responsibility for the service they are requiring and using, nor does it design rates to promote customer avoidance of cost responsibility. Thus, the evaluation of "how current rate design impacts customers' ability to reduce their grid demand during monthly peak load hours or on-peak periods through active load management or through the adoption and operation of DER," is fundamentally a customer-side evaluation. The Company's central focus is designing rates that are fair, reasonable and appropriate for all customer segments, with all customer segments having a reasonably comparable responsibility for system costs.

Prior Referenced Responses:

[i] UCONN-018 Question:

(Rate Design & Tariff Structure) Explain how the proposed rate design provides University of Connecticut and UConn Health with economically efficient price signals while recognizing their continuous, research-related, healthcare, and mission-critical operations.

a. Identify any optional rates or programs available for flexible load, demand response, energy storage, or system-peak reductions.
b. Identify any alternative rate designs considered for such customers and explain why each was accepted or rejected.

UCONN-018 Response:

a. Eversource is wholly aware that the service it is providing to customers is an essential service that must be delivered with a high degree of reliability at an affordable price for all customers. In that context, there are two fundamental realities that apply: (1) the business of delivering safe and reliable power to customers is an infrastructure-centric endeavor; and (2) the costs of building, maintaining, reinforcing and upgrading that infrastructure are borne across a wide range of customer classes that make differing use of the system and that have differing methods and capabilities to pay for that use. In that context, the rates that the Company has proposed in this proceeding were developed using the Company's actual costs incurred and established methods to allocate those costs across the customer base in accordance with the use of the system. Eversource deeply respects the mission of both UCONN as an educational institution and UCONN Health as a research-related and healthcare institution, and the integrity of those institutions in meeting that mission. However, utility rates are, by definition, designed to be collectively applied across a broad disparity of customers, including residential customers. This means that, attempting to craft "optional rates or programs available for flexible load, demand response, energy storage, or system-peak reductions," will typically create costs for some other customer segment, most notably, residential customers. Consequently, these types of initiatives are ones that make more sense when undertaken by the specific customer seeing those types of initiatives as beneficial to their economic interests.

b. The Company did not consider creating a special rate or rate structure for educational institutions or healthcare institutions.

   Eversource is a longstanding partner in advancing UCONN's research-related, healthcare, and mission-critical operations through energy efficiency and demand management. UCONN is one of Eversource's largest commercial and industrial (C&I) participants in the Conservation & Load Management (C&LM) programs offered through the Energize Connecticut initiative. As a key strategic customer, UConn works closely and participates in monthly meetings with dedicated Eversource Energy Efficiency Account Executives and Consultants to identify opportunities, develop projects, and maximize participation in available energy efficiency programs.

   Across UCONN's Storrs campus, regional campuses, hospitals, and health centers, Eversource provides technical assistance, engineering support, project development expertise, and C&LM incentive funding. Over the past 3+ years alone, Eversource has supported **295 UCONN energy efficiency projects**, delivering more than **$2.1 million in C&LM incentives funded by ratepayers**. These projects span a broad range of Energize Connecticut offerings, including custom energy efficiency projects, lighting and equipment rebates,

building system optimization initiatives, and incentives for new and replacement high-efficiency equipment. UConn also participates in Eversource-supported **Active Demand Response** programs, helping reduce peak demand, enhance grid reliability, and lower system costs at **five sites**.

Beyond C&LM program delivery, Eversource supports workforce development and energy innovation through its involvement with **UCONN's Southern New England Industrial Training and Assessment Center** (ITAC). As a **funding partner and advisory board member**, Eversource provides strategic guidance and collaborates with faculty to help develop the next generation of energy efficiency professionals. Eversource employees also mentor graduate students and support senior engineering capstone projects through technical consultation and project review.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) In Massachusetts Department of Public Utilities Docket No. 22-22, Eversource's most recent distribution rate case for its Massachusetts service territory, Eversource was ordered to offer a voluntary, opt-in rate option to its large commercial customers in Eastern Massachusetts that incorporates a coincident peak rate design for transmission charges. Under this rate design, participating customers are assessed a monthly transmission demand charge based on a customer's average 60-minute grid demand (in kW) measured during Eversource's monthly peak load hour measured in aggregate for the purposes of ISO New England regional network service cost allocation.

a. Please explain why Eversource did not include a similar coincident peak rate design option for its large commercial customers in Connecticut as part of its rate design proposal.
b. Please explain whether Eversource plans to implement a coincident peak transmission rate pilot for large customers in the Company's New Hampshire service territory.
c. Is Eversource aware of other electric utilities in New England that currently offer a coincident peak transmission rate option for large commercial customers?
d. Does Eversource have the administrative and technical infrastructure in place to offer a voluntary coincident peak transmission rate option for its large commercial customers in Connecticut? If not, please identify (i) each required system modification and its estimated cost, and (ii) any other administrative or technical obstacles to offering a voluntary coincident peak transmission rate.

Response:

a. The Company's purpose and focus in this application is distribution rates.

b. Yes. This type of rate exists in other jurisdictions that have made a policy decision that the inequities inherent in this type of rate for residential and small or medium commercial and industrial customers are outweighed by other policy factors, including Massachusetts.

c. Such an option is not proposed. The requirements, capabilities, need for modifications, costs, obstacles for development and implementation of such a rate, and other considerations that potentially would need to be addressed have not been evaluated.

d. Yes, the Company is aware that its affiliate, NSTAR Electric Company in Massachusetts has such a rate, as well as one or two other companies in New England.

e. Based on Eversource's experience with this rate, the Company views this type of rate as inherently inequitable for other customer segments, including residential customers. The basic premise of the rate is to allow the rate-taker to avoid cost responsibility. This type of rate inherently favors more sophisticated customers, while imposing burden on other smaller customers. Therefore, the Company is not supportive of this type of rate design.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Please identify any differences between the rate design for intermediate and large commercial customers in Eversource's Connecticut service territory and the rate design for equivalent customer classes in its Massachusetts and New Hampshire service territories, including, but not limited to:

a. Billing determinants (kVA vs. kW).
b. On-peak hour definitions.
c. Seasonal rate differentiation.
d. Coincident peak or time-of-use rate options.
e. Formulation and allocation of distribution and/or transmission costs.

Response:

The following provides a summary of high-level differences in rate design, for comparable intermediate and large general service rate classes, among Eversource's affiliated operating companies in Connecticut, Massachusetts and New Hampshire.

a. kW vs. kVA, and billing demand definitional differences.
    - CT: kVA ratchet for distribution and related components; on-peak monthly maximum kVA for transmission and CTA)
    - MA: Western peak hour kW; Eastern: kVA billing for Cambridge & South; max kW or 90% of kVA for Boston;
    - NH: ratcheted kVA, peak and off peak based (large); max of peak kVA or 50% off peak, power factor adjusted (intermediate)

b. Peak vs. off-peak periods.
    - CT: for TOU demand charges: 12 noon to 8 pm EST (1 pm-9 pm DST), weekdays; all other hours off-peak
    - MA: with ratchet to capture demand in off-peak,
        - Boston: Summer (June to Sept) is 9 am to 6 pm), Winter (Oct to May) is 8 am to 9 pm. Weekends and holidays are off peak.
        - Cambridge/South: Uses DST to establish seasonality. DST is 9 to 6 pm peak. EST is 4 pm to 9 pm. Weekdays and holidays are off peak.
        - West: 12 noon to 8 pm EST is on peak. All other hours is off peak.

- NH peak is 7 am to 8 pm weekdays. Weekends and holidays are off peak.

c. Seasonality applies to time periods but there is no seasonality in rates

d. Coincident peak optional for eastern MA, Rate G-3 and mandatory for western MA, Rate T-5. NH is in active docket but not offered at this time.

e. Formulation and allocation of distribution and transmission costs
   - Distribution rate class allocations using allocated distribution cost of service study (resource based) and rate design parameters in CT, MA and NH.
   - Transmission rate class allocation uses 12 CP allocation of transmission service charges (financial based) and rate design parameters in CT, MA and NH.

Date Filed: October 02, 2026

Witness: Edward A. Davis, Kimberly R. Parsons and Joseph D. Rubino
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Does Eversource manually bill any of its Rate 55, 56, 57, or 58 customers? If so, please provide the number of accounts that Eversource manually bills and the monthly cost for Eversource to perform manual billing for these accounts.

Response:

Eversource manually *calculates* bills for 348 customers on Rates 55, 56, 57, and 58, broken out as follows:

- Rate 55 = 52 accounts
- Rate 56 = 224 accounts
- Rate 57 = 25 accounts
- Rate 58 = 47 accounts

The calculations are undertaken using the Large Power Billing ("LPB") system[1]. Then, the bill amounts are manually entered into the Company's customer information and billing system ("C2"). The C2 system records the revenue and provides information needed for bill rendering, which requires sending information to third party providers who deliver the bills electronically or via U.S.P.S. mail.

For the manual work to *calculate* the bills and enter the information into the C2 system, it takes approximately three full time employees. The *labor* costs to manually perform this work on these accounts is approximately $16,300 monthly, or $195,600 annually. In addition to labor costs, there are IT system costs that are incurred to maintain records.

[1] The Company currently has an IT project under way to replace the current LPB system.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Refer to Exhibit CLP-RATES-1 pp. 14-15 and Exhibit CLP-RATES-2 pp. 19-22.

a. The proposed distribution demand charges for Rates 55 through 58 represent increases of approximately 59% to 75% compared with distribution rate increases of 28.5% for residential customers and 45.5% for small commercial load. Please identify and quantify each factor that contributes to these proposed increases for intermediate and large commercial customers.

b. Eversource states that the ROR index for "intermediate business classes" moved from an average of 2.7 under current rates to 1.2 under proposed rates, while the ROR index for Rates 1 and 7 moved from 0.3 to 0.9. Please explain why a movement of this magnitude in a single rate case—rather than a more gradual transition—is appropriate and consistent with principles of rate stability and avoidance of rate shock.

c. Has Eversource evaluated the risk that distribution demand charge increases of this magnitude could incentivize large commercial and industrial customers to pursue load reduction strategies (including behind-the-meter generation, energy storage, or relocation) that would reduce Eversource's revenue base and shift costs to remaining ratepayers? If so, please provide the results of any such analysis. If not, please explain why such an analysis was not performed.

Response:

a. Please refer to Exhibit CLP-ACOS-2 for the detail on the expenses allocated to Rates 55 through 58 which, compared to current distribution revenue, contribute to the distribution revenue increase proposed in this proceeding. The driver of the increases for these customer segments is the increased cost of service that is the subject to this proceeding.

b. As shown in CLP-RATES-1, the current total Company ROR is 1.05%. The current ROR of Rates 1 and 7 is 0.3% (less than total) while the current ROR of the intermediate business classes is 2.9% (greater than total). To move all rate classes closer to an index of 1.0, where each rate class would be contributing equally to the total Company ROR, Rates 1 and 7 required a greater share of the total proposed increase than the intermediate business classes. Per the proposed revenue increase allocation provided in Exhibit CLP-RATES-2.1, the intermediate business classes received 93.6% of the average increase (50.6%) while Rates

1 and 7 received 102% of the average increase. If the company further decreased the allocation percentage to the intermediate business classes, other rate classes would have needed to be designed with a higher percentage increase than the Company considered reasonable to support the shortfall in increase to this class relative to their cost of service. As stated in the pre-filed testimony Exhibit CLP-RATES-1, the Company sought to recover overall costs while striking a balance between assigning an appropriate level of cost responsibility to each rate class, maintaining reasonable bounds (75% to 125% of the average increase) around changes to rates and impacts to customers.

c. Eversource consistently considers the risk that distribution demand charge increases of *any* magnitude could incentivize large commercial and industrial customers to pursue load reduction strategies (including behind-the-meter generation, energy storage, or relocation), when presenting rate designs to PURA for rate implementation. The pricing impacts and economic incentives that utility rates create are inherent in every rate change that the Company ever presents to its regulators for review. However, providing safe and reliable electric services to customers is fundamentally an infrastructure business that requires substantial and consistent investment in that infrastructure. Therefore, the Company is called upon to balance the interests of all customers in converting those costs to rates that customers will pay. The results of that balancing are presented in the Company's analysis and exhibits in this proceeding.

Date Filed: October 02, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Rate Design & Tariff Structure) Explain how the proposed rate design provides University of Connecticut and UConn Health with economically efficient price signals while recognizing their continuous, research-related, healthcare, and mission-critical operations.

a. Identify any optional rates or programs available for flexible load, demand response, energy storage, or system-peak reductions.
b. Identify any alternative rate designs considered for such customers and explain why each was accepted or rejected.

Response:

a. Eversource is wholly aware that the service it is providing to customers is an essential service that must be delivered with a high degree of reliability at an affordable price for all customers. In that context, there are two fundamental realities that apply: (1) the business of delivering safe and reliable power to customers is an infrastructure-centric endeavor; and (2) the costs of building, maintaining, reinforcing and upgrading that infrastructure are borne across a wide range of customer classes that make differing use of the system and that have differing methods and capabilities to pay for that use. In that context, the rates that the Company has proposed in this proceeding were developed using the Company's actual costs incurred and established methods to allocate those costs across the customer base in accordance with the use of the system.

   Eversource deeply respects the mission of both UCONN as an educational institution and UCONN Health as a research-related and healthcare institution, and the integrity of those institutions in meeting that mission. However, utility rates are, by definition, designed to be collectively applied across a broad disparity of customers, including residential customers. This means that, attempting to craft "optional rates or programs available for flexible load, demand response, energy storage, or system-peak reductions," will typically create costs for some other customer segment, most notably, residential customers. Consequently, these types of initiatives are ones that make more sense when undertaken by the specific customer viewing those types of initiatives as beneficial to their economic interests.

b. The Company did not consider creating a special rate or rate structure for educational institutions or healthcare institutions. However, UCONN is the beneficiary of numerous program benefits that Eversource offers to large commercial customers. For example, Eversource is a longstanding partner in advancing UCONN's research-related, healthcare, and mission-critical operations through energy efficiency and demand management. In fact, UCONN is one of Eversource's largest commercial and industrial participants in the Conservation & Load Management (C&LM) programs offered through the Energize Connecticut initiative. As a key strategic customer, UConn works closely and participates in monthly meetings with dedicated Eversource Energy Efficiency Account Executives and consultants to identify opportunities, develop projects, and maximize participation in available energy efficiency programs.

In addition, across UCONN's Storrs campus, regional campuses, hospitals, and health centers, Eversource provides technical assistance, engineering support, project development expertise, and C&LM incentive funding. Over the past 3+ years alone, Eversource has supported approximately 295 energy efficiency projects for UCONN, delivering more than $2.1 million in C&LM incentives funded by Eversource's customers. These projects span a broad range of Energize Connecticut offerings, including custom energy efficiency projects, lighting and equipment rebates, building system optimization initiatives, and incentives for new and replacement high-efficiency equipment. UConn also participates in Eversource-supported Active Demand Response programs, helping reduce peak demand, enhance grid reliability, and lower system costs at five sites.

Beyond C&LM program delivery, Eversource supports workforce development and energy innovation through its involvement with UCONN's Southern New England Industrial Training and Assessment Center (ITAC). As a funding partner and advisory board member, Eversource provides strategic guidance and collaborates with faculty to help develop the next generation of energy efficiency professionals. Eversource employees also mentor graduate students and support senior engineering capstone projects through technical consultation and project review.

Date Filed: October 02, 2026

Witness: Douglas P. Horton, Edward A. Davis and Kimberly R. Parsons
Request from: UCONN

Question:

(Performance Based Rates) Refer to Exhibit CLP-RATES-3 at p. 192 indicating that the Performance-Based Multi-Year Rate Plan ("PBMRP") Rider is authorized for a four-year term starting July 1, 2027.

a. For each of Rates 55-58, please provide the annual projected billing impact of the PBMRP Rider for each year of the proposed four-year PBMRP term. If no such projected annual rate impact analysis was conducted, please explain why.
b. provide the projected annual and cumulative percentage change in total delivery rates for each of Rates 55, 56, 57, and 58 for each year of the PBMRP term, attributable to the combined PBMRP adjustments (I-X, F-Factor, Consumer Dividend, earnings sharing mechanism, and any other anticipated adjustments).
c. State all assumptions used in preparing the projections.

Response:

Please refer to AMTRAK-012, Attachment 1. Each tab provides illustrative incremental distribution increases for the rate-year specified, based on the Company's proposed PBMRP. Lines 42, 44, 46, and 48 provide Rate 55, 56, 57, and 58, respectively. Column L provides the incremental distribution revenues, while column AU provides the annual percentage increase presented on a total bill basis. For ease of reference, the Company has summarized the requested amounts in UCONN-19, Attachment 1.

a. Per UCONN-19, Attachment 1, Lines 5-8 provides incremental revenues and annual percentage changes for each of the requested rates. Column F provides the incremental distribution revenue for Rate Year 2, while Column G provides the corresponding annual percentage total change. Column I and Column J provide the incremental distribution revenue increase and percentage increase in total, respectively, for Rate Year 3. Column L and Column M provide the incremental distribution revenue increase and percentage total increase, respectively, for Rate Year 4.

b. Lines 15-18 provide the corresponding cumulative amounts for each of the rate years. Finally, Column O provides the annual average percentage increase, which is approximately 1.2% for each of Rate 55 and Rate 56, and 1.0% per year for each of Rate 57 and Rate 58.

c. Please refer to the Company's response to data request EOE-156[i], which provides the model and discussion related to the increases referenced in parts a and b above.

Prior Referenced Response:

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[i] EOE-156 Question:

(PBMRP CAPITAL SUPPORT MECHANISM) Refer to Exhibit CLP-ELP-1, pp. 101-103. Provide a working, unlocked Excel spreadsheet that would serve as a representative tool used to calculate the Company's incremental revenue requirements resulting from the proposed capital support mechanism (F-Factor) for each year of the MRP. As part of the submission, discuss the calculations and separately identify and explain all critical assumptions, using cited information from the Company's rate case submission where relevant (e.g., depreciation rate from the Company's depreciation study). In support of the request, please use the Company's proposed 5-Year Targeted System Performance (TSP) Plan within the spreadsheet's initial inputs and apply an initial assumption that the Company incurred actual plant-in-service additions of 5% more than the proposed annual TSP funding. Additionally, please configure the spreadsheet to allow for the weighted average carrying costs (WACC) to be individually adjusted for both ROE and Cost of Debt.

EOE-156 Response:

The Company appreciates the opportunity to respond to EOE's thoughtful question regarding the operation of the PBMRP proposed in this proceeding, which the Company views as key to reaching a long-term reliability and resiliency plan for Connecticut, while meeting affordability needs for customers.

The Company's response to this request is organized as follows:

A. Overview and Results

B. F-Factor Discussion

C. Impact of 5% Additional Capital Investment

D. Model overview

Attachments referenced in this response:

EOE-156, Attachment 1, provides the Company's working model, with projected capital investment as filed in this proceeding. See, e.g., Exhibit CLP-ELP-1, Figure 7.
EOE-156, Attachment 2, provides a second model that is identical in every respect to Attachment 1 except that capital investments are 5% greater than the forecast submitted to this proceeding in Exhibit CLP-ELP-1, Figure 7, as stipulated by EOE's data request.

A. Overview and Results

Ultimately, the Company's goal in this proceeding is to establish a sustainable, cohesive ratemaking framework that supports electric utility service in the State of Connecticut in an affordable manner for

customers, over a long term. This is the Company's goal because the CL&P system needs investment for reliability, resiliency and modernization. For this infrastructure investment to be affordable for customers, a coherent ratemaking plan needs to be instituted that will consider the interests of customers over a longer term than just the next rate case. That framework needs to balance: (1) the reliability and performance requirements of the Company's customers and the broader State of Connecticut; (2) customer rate stability and affordability;
(3) incentives for cost efficiency in utility operations; and (4) implementation of a revenue support mechanism sufficient to cover the cost of delivering these objectives to customers, including the cost of capital.

The Company's PBMRP is designed to address these objectives in a holistic, balanced way. To do this, the Company started with the ratemaking framework under discussion in PURA's PBR docket (Docket No. 21-05-15RE01), while also introducing certain new elements to remediate the flaws that would ultimately hinder PURA's (draft) PBR model from supporting the necessary stay-out terms. As discussed below, the stay-out term is the critical element of the PBMRP that creates the cost-efficiency incentive inherent in a performance based ratemaking plan.

This context is vital to understand both the design and mechanics of the Company's proposed PBMRP, including both the F-Factor and "I-X" components. To augment understanding of how the plan would work over the stay-out period, the Company has incorporated the projected costs of service set forth in EOE-156, Attachment 1, Worksheet, entitled "COS-1 Total," which is the Company's cost of service, as filed. The Company does not intend to imply that these dollar amounts are certain for the future and there will undoubtedly be changes in a litigated result. However, these figures serve as a reasonable basis for presenting this analysis to reflect the Company's PBMRP proposal. Moreover, assuming that there will be changes to the underlying cost of service that serves as the "going in revenue requirement," all of the projections made herein become highly optimistic, as discussed below.

Increasing capital investment on the Connecticut distribution system is a given for the reasons described in the testimony of the Company's Leadership Panel and Targeted System Plan ("TSP") Panel – the Connecticut distribution system needs additional investment to maintain service reliability to customers and even more investment to achieve a level of modernization. The Company will need to make this investment to meet the interests of customers, with or without a multi-year plan. However, *without a multi-year rate plan*, whether in the form of the Company's proposed PBMRP or another reasonable model, the Company's only viable course of action to support this level of needed investment will be to file traditional cost-of-service rate cases, as closely to annually as possible. Effectively, these sequential cases will "roll in" unrecovered capital investment into base rates to maintain a nexus between what the Company needs to invest in the system and what rates are reflecting for recovery of costs.

In a world in which system investment needs are relatively flat, economy-wide inflation is modest and predictable at 2% annually, and rates are fully coupled with growing sales revenues (and no revenue decoupling mechanism), it is conceivable that a utility *could* offset the cost increases it incurs with organic sales growth, as electric utilities could do in past decades. However, that is not the reality of today's operating environment. The distribution system investment needs are extensive and growing and the financial consequences of these circumstances are factors that need to be considered in determining a reasonable and workable regulatory plan. Establishment of a reasonable multi-year, performance-based ratemaking plan is the mechanism that can support the system needs in a manner that is wholly transparent and stable for customers, allowing for a smoother trajectory of rate changes than would otherwise occur.

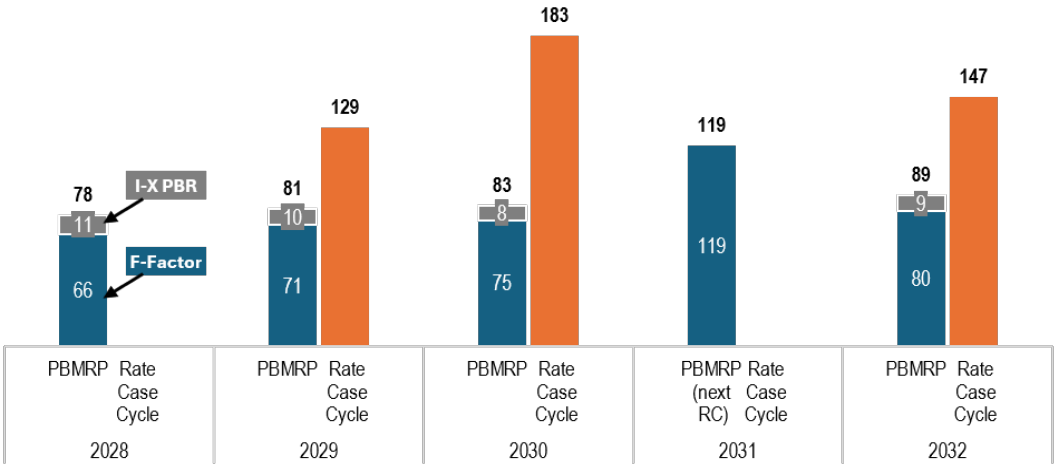
<u>Results of F-Factor Implementation Assuming Capped Forecast Investment</u>

EOE-156, Chart 1, below, provides illustrative rate increases comparing circumstances where the Company is pursuing a traditional rate-case cycle with filings as close to annually as possible under Connecticut law, as compared to the proposed PBMRP. These amounts assume the Company's revenue requirement proposed in this docket is authorized *without modification*, except that the Company has used its existing weighted average cost of capital to perform the analysis, in order to isolate the functioning of the F-Factor operation - apart from changes in the cost of capital (i.e., the analysis uses a 9.25% return on equity and 47%/53% debt to equity capital structure). As noted above, the cost-of-service projections are shown in EOE-156, Attachment 1, Worksheet "COS-1 Total," Line 35.

In the absence of a multi-year rate plan, the Company anticipates filing rate cases on a rolling basis, with base rate changes effective January 1, 2029, July 1, 2030, and January 1, 2032. Chart 1, below, also spans the time period covering one year beyond the Company's proposed four-year plan. 2032 is shown for illustrative purposes

EOE-156, Chart 1

Annual Incremental Revenue Increase, $ Millions



Note: Chart 1 assumes base-rate amendments effective 1/1/2029, 7/1/2030 and 1/1/2032.

In Chart 1, a rolling rate-case cycle is depicted as the orange series, with the Company estimating new rates effective January 1, 2029 (18 months after the present docket concludes), with additional revenues of $129 million; followed by another $183 million rate change effective July 1, 2030, and a further $147 million effective January 1, 2032. These rate adjustments arise primarily as a result of capital investment rather than O&M changes, which means that the associated rate changes are reasonably foreseeable and ultimately predictable.

In contrast, the Company's proposed PBMRP would yield revenue increases of $77.6 million for rates effect July 1, 2028, $81.1 million July 1, 2029, and $83 million July 1, 2030 (EOE-156, Attachment 1, worksheet "PBR-1 Total PBRA", Line 41). For purposes of discussion, the Company estimates that the subsequent rate case taking effect after the proposed PBMRP would be $119 million in 2031, followed by $89 million in 2032 assuming continuation of the proposed framework. Uncertainty grows as the timeframe of projections extends, as the Company will inevitably experience cost increases in relation to both operating expenses and capital investment, as time passes. Therefore, the later years (particularly 2031 and 2032)

should be interpreted as illustrative for purposes of discussing the principles and conceptual impacts of the PBMRP and traditional rate case frameworks.

As Chart 1 illustrates, whether through a multi-year rate plan or sequential rate cases, ongoing revenue support is essential to the electric system. Revenue increases for the Company are rate increases for customers, so that a smoother and more predictable customer impact occurs through the Company's PBMRP, which is the fundamental purpose of the PBMRP.

The Company's proposal results in rate increases amounting to approximately 1.5-2.1% on a total bill basis, annually (Line 3). In contrast, a rolling rate-case cycle yields rate increases nearly double at 3.4% (Line 4). Essential to this discussion is that *both* frameworks are designed to roughly track with the cost of service, although the stay-out feature of the PBMRP forces the Company to absorb the risk of deviation from the cost of service given the likelihood that operating and investment costs will increase over the period. The difference is the gradualism of the Company's PBMRP, which results in smoother, more predictable bill changes for customers.

EOE-156, Table 1

Line	Description	2028	2029	2030	2031	2032
	Incremental Revenues ($ Millions)					
1	Company Proposal	77.6	81.1	83.0	118.6	89.0
2	Rate Case Cycle	0.0	129.0	183.0	0.0	147.0
	Annual Increase, % Total Bill					
3	Company Proposal	1.5%	1.5%	1.5%	2.1%	1.6%
4	Rate Case Cycle	0.0%	2.4%	3.4%	0.0%	2.6%

The rolling rate-case cycle is characterized by larger changes that are more disruptive to customers, in addition to being administratively burdensome for all Connecticut stakeholders. Importantly, the Company's PBMRP does not undermine the applicability or efficacy of prudence reviews in terms of establishing a strong incentive for cost control. Under the Company's proposal, prudence reviews can occur annually, preserving accountability and cost-control incentives with increased transparency, as well.

B. F-Factor Operation

At its core, the Company's proposed F-Factor mechanism is designed to provide a revenue allowance sufficient to support the level of capital investment needed by the system, including the cost of capital. Several essential characteristics of the F-Factor mechanism mutually contribute to its viability and potential longevity:

1. **Like the CT-Bar the Company's F-Factor would take effect the first day of the first Rate Year coming out of the rate case, which eliminates the need for Rate Year capital to be embedded in base rates, subject to later downward-only reconciliation**. To the extent capital investment currently factored into the Company's proposed revenue requirement for Rate Year 1 is "rolled back" to an earlier date (for example, to a capital investment cutoff date of February 28, 2027 for inclusion in base rates), the F-Factor revenue-requirement calculation would inherently adjust to reflect capital investment as of that cutoff date.

2. **Like the CT-Bar, the Company's F-Factor does not pre-emptively or categorically exclude any type of capital investment**. The Company regularly makes capital investments that do not directly affect the performance of the electric grid the way utility poles, transformers, lines,

substations, etc. clearly do, but are nonetheless essential capital investments in the provision of service to customers. Capital investments for facilities safeguarding equipment, information technology enabling self-service customer portals, and vehicles needed for transporting materials to work sites are but a few examples of core capital investments that are necessary and, therefore, inform the F-Factor allowance.

3. **Like the CT-Bar, the Company's F-Factor aligns the capital investment necessary for the target performance of the electric grid outlined in the Company's Targeted System Plan, with the revenues required to support those investments.** In developing the F-Factor the Company sought to establish a means of tying the F-Factor revenue allowances to the capital investment forecast that would be discussed extensively in this docket. This allows the focus of the TSP to remain on the system needs and plan objectives while simultaneously acknowledging that those needs and objectives, whatever they may be, require some measure of revenue support. The F-Factor serves as a necessary link between the system needs evaluated in *this* docket and necessary revenues.

4. **The Company's F-Factor properly includes the cost of capital**. If CT-bar is evaluated separately from going-in revenue requirements, no single design factor would guarantee its failure more so than the absence of the cost of capital from its revenue requirement calculations. Though the cost of capital is not visible the way other costs of service are, such as the maintenance cost that keeps an older piece of equipment online or the cost of gasoline in a line truck, it is just as real a cost of service.

   The Company regularly operates with a cash deficit. That is, the cash necessary to support *ongoing* operations exceeds the cash received from customers through bills. The direct result is the Company must secure funds through some other means. Those other means are debt and equity investors: the individuals, banks, corporations and other institutions supplying funds to capital markets. Those entities have choice in terms of the entities to whom they provide their funds, choices that weigh other utility companies, industries, countries and continents, type of security, duration, expected return, the presence (or absence) of dividends, environmental, social, and governance characteristics, and countless other variables against the investor's tolerance for risk. Not surprisingly, the Company cannot expect that investors, facing the choice between the Company and essentially all other investment opportunities, would or should accept zero return in exchange for their funds. Thus, the cost to acquire the funds necessary to perform the ongoing capital investments *required* of the system is real, fundamentally non-zero, and more specifically the Company's cost of capital filed in this proceeding.

5. **The Company's F-Factor captures all elements of the Company's capital investment base, including plant additions, plant retirements, accumulated depreciation, cost of removal, and accumulated deferred income taxes.** The Company's F-Factor calculation fundamentally captures the impact of ongoing depreciation accumulating in rate base, which has the effect of reducing overall revenue requirements. Additionally, the Company's F-Factor calculation inherently captures the reduced revenue requirement resulting from plant retirements and accumulated deferred income taxes, while also incorporating the effect of cost of removal on rate base.

6. **Like the CT-Bar, annual reconciliation of the revenue requirement ensures customers ultimately pay only for prudent capital investment while balancing the utility's need to cover the *ongoing* costs of providing ongoing service.** Critically, the Company's F-Factor

proposal does not circumvent prudence reviews – essential pillars of properly-functioning regulatory frameworks – nor undermine the value that effective prudence reviews bring customers. Ultimately, the Company is acutely aware that any capital investment must successfully withstand the scrutiny of a prudence review. Whether that review happens next year, three years from now, or at any other interval, the Company knows the decisions made today must withstand a prudence examination. Any eventual findings of imprudence regarding capital investments made today have significant, negative financial implications, regardless of when those findings are made. Thus, the very expectation of future prudence reviews reinforces the prudence ingrained in decision-making today. Further, the risk of a future finding of imprudence and the negative financial implications thereof eliminates any perceived financial benefit for the Company to "over invest" today.

Annual reconciliation, including the prudence reviews involved, is a critical element of the Company's PBMRP proposal. As part of each annual PBMRP adjustment effective July 1 each year of the PBMRP[2], the Company's actual capital additions for the Prior Year are allowed for inclusion in the calculation of the F factor to the extent that the actual capital additions do not exceed the Forecasted Budget (referred to as the F-factor allowance). To the extent that the cumulative actual capital costs in-service through the Prior Year, in aggregate, exceeds the Forecasted Budget through the Prior Year, then the F Factor allowance is capped at the cumulative Forecasted Budget. This downward-only reconciliation will ensure that, in the end upon reconciliation, customer bills reflect the costs associated only with projects that are in service to customers and no more, and that if the Company invests more than the Forecasted Budget, customer bills will not reflect amounts above the Forecasted Budget, until such time as those capital investments are allowed into rates at the time of the Company's next rate case. The prior-period reconciliation will be reflected in the F-Factor, in addition to the revenue requirement associated with the Forecasted Budget for the upcoming rate year, effective July 1 annually. The F Factor allowance will be calculated to determine the revenue requirement (inclusive of depreciation expense, property tax expense, return on rate base, and income tax) on actual plant additions (including plant additions, cost of removal, plant retirements, accumulated depreciation, and plant-related accumulated deferred income taxes ("ADIT")) up to the Forecasted Budget amount, and to reflect the revenue requirement for the Prior Year and through the Rate Year on in service capital additions placed in service in the Prior Year, provided that those in service capital additions are not reflected in base rates or in another rate mechanism. In addition, the F Factor allowance will reflect the revenue requirement for rate year capital, established at the Forecasted Budget, subject to downward-only reconciliation in the subsequent F Factor filing.

As noted above, annual reconciliation will consider plant-related ADIT on the Company's books through the end of the calendar year, prior to a given annual filing. To the extent the Company has recorded cumulative plant additions in excess of the capital expenditure forecast provided in this docket or supported by a mechanism other than the F-Factor, the plant-related ADIT will be adjusted in the Company's annual reconciliation to avoid overstating the ADIT relevant to the F-Factor.

In total, the Company's proposed F-Factor will provide revenue support for, and ultimately reconcile, the capital investment placed into service from the cutoff date for inclusion in base rates through the effective date of the Company's subsequent rate case at the conclusion of the proposed PBMRP term. Per the Company's proposal, and as depicted in the illustrative attachments for this response, the F-Factor would ultimately reconcile capital investments made

up to July 1, 2031 (the effective date of the subsequent rate case). Should the subsequent rate case be effective later than the July 1, 2031 illustrative date, the F-Factor would continue to reconcile capital investments placed into service until such time as that rate case does take effect.

C. Impact of 5% additional capital investment

EOE-156, Attachment 2 is the same working model as Attachment 1, except that the Company's actual capital investments are assumed to be 5% greater than the current forecast. These increases are reflected on the worksheet "COS-2 Capital," at Lines 19 and 26.

As shown in EOE-156, Table 2, below, in the event that the Company's actual capital investments over the period 2027-2031 were 5% greater than current projections, which is a realistic scenario, the Company's proposed F-Factor revenue would ***not increase***, highlighting two crucial design characteristics.
First, the core capital investment forecast provided in this docket is proposed to be a hard cap on the capital plant additions eligible for recovery through the F-Factor. That means the Company, PURA and stakeholders will be adequately informed of the *maximum* future revenues as calculated *today*.

Second, where core plant additions greater than forecast will not be supported through the F-Factor mechanism, there is pressure on the Company to stretch to find efficiencies to maintain a viable rate of return. As Table 1 demonstrates, investing beyond the current forecast provides no benefit in the form of greater revenue during the PBMRP, while putting downward pressure on the Company's earned rate of return. Consequently, over the term of the PBMRP, the Company's financial interest is to operate within its budgets and with a high rate of efficiency in order to achieve a viable rate of return.

EOE-156, Table 2

	Rate Year 1	Rate Year 2	Rate Year 3	Rate Year 4
Base Capital Investment Forecast				
(As Filed, Docket No. 26-05-10)				
Annual Incremental F-Factor Revenue ($ millions)		$66.2	$71.4	$74.5
Return on Equity	9.10%	8.98%	8.87%	8.75%
Savings required to earn allowed ROE ($ millions)	**$7.6**	**$14.3**	**$21.2**	**$29.0**
5% Additional Capital Investment				
Annual Incremental F-Factor Revenue ($ millions)		$66.2	$71.4	$74.5
Return on Equity	9.01%	8.80%	8.61%	8.42%
Savings required to earn allowed ROE ($ millions)	**$11.9**	**$23.8**	**$36.1**	**$49.3**

As shown in Chart 1 and discussed previously the sequential rate cases have a larger impact for customers and are more disruptive, while also creating administrative burden for all Connecticut regulatory stakeholders. Conversely, the Company's PBMRP produces smoother changes in revenues/rates without undermining the importance or efficacy of prudence reviews that would occur in the traditional cost-of-service ratemaking context. Under the Company's proposal, prudence reviews would happen annually. Thus, accountability and cost-control incentives are preserved in the Company's proposal, with an improvement in ratemaking transparency.

However, the larger point illustrated in Table 2 is the powerful impact of the stay-out term.

Under PBR, a benefit for the Company is the line of sight it has on a predictable revenue stream that will replace the loss of sales growth associated with the revenue decoupling mechanism, while providing a level of support for the ongoing operation of the system, including needed investment. However, a significant risk for the Company is that its costs will deviate from the "going in revenue requirement" from the minute rates are set through

the end of the stay-out term. These cost changes will impact operating expenses, as well as the drivers of investment costs.

The power of the stay-out term, therefore, arises in relation to the Company's impetus to offset the earnings attrition it will inevitably experience as a result of these cost changes, through efficiency initiatives that will reduce costs on a going forward basis, to the benefit of customers. That is, to maintain a viable rate of return, the Company will be pressed to seek out and achieve cost efficiencies somewhere in the business. Those efficiencies achieved during the stay-out period unavoidably inure to the benefit of customers when base-rates are next set on a cost-of-service basis. This is the fundamental power of a PBR framework, which the Company is experiencing in its Massachusetts companies.

In this case, Table 2 (above) and the working model included as part of this response, each show that it would be necessary for the Company to realize cost savings of approximately
$29 million annually, by the end of the PBR term, in order to be able to offset the downward pressures on the (currently) authorized return on equity ("ROE") of 9.25%, all else equal. (See, EOE-156, Attachment 1, worksheet "Financial Summary", Line 24). "Downward pressures" mean increased costs, whether operating expense or the cost of carrying unrecovered capital investment.

For context, the Company's O&M reflected in this docket (per Exhibit CLP-REVREQ-2, Schedule C-3.0), excluding vegetation management, storm restoration and uncollectible expense, is $352 million, annually. Cost efficiency gains of $29 million therefore equate to a reduction on total O&M of approximately 8 percent, which is a significant reduction in the normal course of business.

At the same time, Table 2 further highlights that this $29 million annual gap is almost doubled to a gap of $49.3 million with only a five percent increase in capital investment as compared to the capped F-Factor. This computation highlights the extreme sensitivity that exists within the cost-of-service ratemaking model when operating expenses and investment costs are increasing and the point at which base rates will be reset and realigned with actual costs is extended to a future point in time.

For example, recall that this analysis is founded on a "going in revenue requirement" that is equal to the Company's filed, proposed revenue requirement – and assumes only one change in the modelling over the entire PBR term, which is the 5% increase in capital investment. However, in reality, there is a virtual certainty of operating cost increases and investment additions that well exceed the 5% shown here, which would only further suppress the rate of return. Accordingly, this analysis highlights the inherent power of the stay-out term associated with a multi-year rate plan that provides revenue support, but without any guarantee of aligning with the actual cost of service along the way. The growing gap is the pressure that is created for efficiency gains that will then be passed on to customers at the next rate-setting interval.

D. Model Overview

Please refer to EOE-156, Attachment 1, for the Company's illustrative PBR model. The model incorporates the Company's proposal with respect to inflation measurement, revenue increases related to operating expenses, F-Factor, and combined effect on the financial results of the Company.

Key assumptions include:

i. The base rate increase, PBMRP, and catastrophic storm cost recovery authorized in this docket are all assumed at the level filed by the Company in this proceeding, with the only exception being the Company used the return on equity and equity capitalization as currently allowed, which is 9.25% and 53.0%, respectively.

ii. The sum of plant additions and cost of removal each year are equal to the capital investment forecast provided in this proceeding, as shown in Exhibit CLP-ELP-1, Figure 7.

iii. Capital and O&M costs related to AMI are excluded from the projected cost of service and illustrative F-Factor revenue requirement calculations. Should the F-Factor be approved as the mechanism enabling revenue support for AMI, the cap on capital investment would need to be increased to accommodate the costs for that program.

iv. Catastrophic storm costs, both the recovery of existing deferred costs as well as the costs related to future events, have no bearing on the model. Importantly, this implies the catastrophic storm and pre-staging costs in base rates perfectly match future costs (i.e. future revenue equals future cost for each and every year).

v. O&M cost pressure is assumed to be 1% greater than inflation, annually.

The model is organized into three primary sections:

1) **Financial Summary**, which presents illustrative results of the combined effect of the Company's proposed rate increase, PBR framework, and cost projections
2) **PBR model**, which covers "I – X – CD" and F-Factor
    a. Worksheet "PBR-1 Total PBRA"
    b. Worksheet "PBR-2 Inflation"
    c. Worksheet "PBR-3 F-Factor Summary"
    d. Worksheet "PBR-4 F-Factor"
    e. Worksheet "PBR-5 F-Factor Property Tax"
    f. Worksheet "PBR-6 Capital Forecast"
    g. Worksheet "PBR-7 Going-In Capital RR"
    h. Worksheet "PBR-8 GDP"
    i. Worksheet "PBR-9 ECI"
3) **Cost of service,** which consists of three worksheets, provides a forecast of the actual cost of providing electric service

1) <u>Financial Summary</u>

The "Financial Summary" provides the combined results of going-in revenues along with the rate increases determined through the Company's PBR proposal, the operating costs of service projected over the same timeframe, and the investment base that enables the Company's essential service to customers.

Lines 15-27 show the calculation of the Company's actual, earned return on equity over the four years of the Company's PBMRP term. Specifically, Line 22 provides the annual earned return on equity; Line 23 provides the cumulative average annual ROE; and Line 24 provides the revenue requirement (excluding GET and uncollectible) or cost savings necessary to achieve the allowed ROE.

Lines 28-44 provide a simplified Income Statement for the four years of the Company's PBMRP, including revenue projections as well as the operating costs of service. These costs represent the projected costs of doing business whether or not those costs are supported with rates.

Lines 46-61 provide a summary of the revenue increases calculated in the PBR model and the corresponding impacts on uncollectible expense and gross earnings tax.

2) PBR

The PBR worksheets are the working calculations that drive the illustrative distribution rate increases discussed above. Each one of which is discussed separately below:

a. Worksheet "PBR-1 Total PBRA"

This worksheet summarizes the results (i.e. rate increases) of the model's other "PBR" worksheets and is organized into four sections: (1) Going-In Revenue Requirements; (2) PBR-O Adjustment; (3) F-Factor Adjustment; and (4) Total Performance Base Revenue Adjustment. "Going-In Revenue Requirements" reflects the eventual revenues authorized as a result of this proceeding. For purposes of this response, this reflects revenues as proposed in this docket and adjusted, as discussed above. The purpose of this section is to orient the reader to the authorized levels of operating revenue (Line 17) and O&M (Line 21) established in this proceeding and, second, to perform calculations necessary to establish Rate Year 1 baselines for use with subsequent rate year revenue calculations. Line 19 is the resulting base distribution revenue requirement that represents the overall starting point for distribution revenues to which any and all PBMRP rate adjustments for Rate Year 2 would be added or subtracted as appropriate. Line 23 is the level of O&M to which the PBR-O percentage increase for Rate Year 2 would apply.

The PBR-O adjustment section (Lines 25-30) provides the calculations for inflation-driven rate increases, which are initially applied to line 23 discussed above. Line 27 is the combined percentage increase resulting from the Company's proposed composite inflation measure, -0.03% productivity ("x") factor, and consumer dividend. For this analysis, the Company has assumed a 30-basis point consumer dividend for all years. Line 28 provides the resulting annual incremental revenues.

The F-Factor adjustment section on this worksheet references the results determined on other worksheets of the model (discussed below). Here, Line 33 provides the resulting annual incremental revenues, while Line 34 provides the cumulative F-Factor revenue requirement.

Line 37 provides the total annual revenue increase, which is the sum of Lines 28 and 33.

Line 43 is the final resulting base distribution revenue requirement that begins with Rate Year 1 amounts and adjusts annually thereafter by the amounts described above.

For purposes of this analysis, there are no exogenous cost recovery assumptions reflected in the accompanying working model. If PURA were to authorize the Company's proposal, including mechanics related to exogenous cost provisions and the consumer dividend, the PBR model would need to be adapted from the attached to include additional worksheets as appropriate.

b. Worksheet "PBR-2 Inflation"

This worksheet first aggregates the relevant indices' data points from worksheets 10 and 11 (discussed below), which are shown on Lines 13-16 for GDP-PI and Lines 21-24 for ECI. Each index is then averaged for a given calendar year (Lines 17 and 25), which then form the basis for the annual growth calculations on Lines 17 and 26. As discussed in the Company's pre-filed testimony, the Company is proposing to weight the indices 66.9% for GDP-PI and 33.1% for ECI. The composite resulting inflation is shown on Line 32.

Line 33 provides the -0.03% productivity factor, while Line 34 shows the consumer dividend, which

assumes 30 basis points for simplicity of this analysis. The combined result of inflation, productivity factor and consumer dividend is shown on Line 35, which is before the imposition of a 5% cap. To the extent line 35 exceeds the proposed 5% cap, Line 36 would provide the adjustment such that Line 37, the final result, is the lesser of the 5% cap and Line 35.

Note that projections of inflation are used for analytical purposes in this response and to assist with discussion pertaining to future rate increase implications. Actual calculations of PBR adjustments in future annual PBR filings would rely exclusively on published data available at the time of a given year's annual PBR filing.

c. Worksheet "PBR-3 Factor Summary"

Like the CT-Bar, the Company's proposed F-Factor is calculated on a monthly basis. The "F-Factor Summary" worksheet aggregates the results of those calculations on Lines 17-29 and presents in 6-month increments to enable both calendar-year and rate-year views of the same information. Property taxes (Line 19) are not calculated monthly, but rather on a fiscal year basis. Line 28 provides the resulting cumulative F-Factor revenue requirement, while Line 29 is the annual incremental amount shown on the worksheet "PBR-1 Total PBRA," line 33.

d. Worksheet "PBR-4 F-Factor"

This worksheet provides the monthly calculation of the F-Factor revenue allowance summarized on the previous worksheet and is the "engine" of the overall F-Factor model. Broadly, it aggregates the necessary inputs, including rate base activity assumptions (Lines 18-25) and relevant rates resulting from this proceeding, including depreciation expense as a function of gross plant (Line 49) and pre-tax return on rate base (Line 51).

Note also that this worksheet includes a "switch" (Line 16) that enables this model to adapt to the cutoff date of capital investment for inclusion in base rates. However, due to the large number of possibilities for a potential cut-off date and similarly large variation of resulting Going-In revenue requirements, the model is currently configured to use this line as an adjustment for Rate Year 1 only. That is, the model is not currently built such that the user can specify a cutoff date for capital investment inclusion in base rates and have that date adjust the going-in capital revenues, as well as the F-Factor. Conceptually, this switch is intended to affix the start of the F-Factor calculations to the last date capital investment is reflected in base rates.

As presently configured, the F-Factor revenue requirement assumes the capital investment reflected in base rates is per the Company's proposal, which is through June 30, 2028. However, the capital-driven rate year revenue requirement calculations reflected in the Company's filed cost of service are based on rate year averages. For example, the rate base referenced in the return on rate base calculations found on Exhibit CLP-REVREQ-2, Schedule A-1.0, Line 16 is average rate base, while Rate Year 1 depreciation expense is based on rate-year average plant in-service, as denoted on WP C-3.34, line 13 of the same exhibit. Consequently, the F-Factor calculation is currently configured to rely on 50% of Rate Year 1 capital investment to effectively build the proper ending balances as of 6/30/2028 upon which subsequent rate year calculations can grow. Note that the interaction between the F-Factor and the cut-off date for capital investment inclusion in base rates is a critical component to the longevity of the Company's proposal as it assures that the F-Factor starting point aligns with the endpoint for base rates, leaving no gap over the duration of the rate plan.

For purposes of this written response, the Company does not detail the calculations of this worksheet here. Instead, the Company refers to the line references provided on the last page of this worksheet (Model PDF, page 8) for both Attachments 1 and 2, which detail the calculations performed. For emphasis, note that Line 33 captures the accumulation of depreciation recovered in base rates. By design, the F-Factor intentionally reflects this to properly estimate a reasonably true capital-driven revenue requirement.

The resulting F-Factor revenue requirement, excluding property tax, which is referenced by the preceding worksheet, is shown on line 53.

e. Worksheet "PBR-5 F-Factor Property Tax"

This worksheet provides the fiscal year calculations for incremental property tax expense based on capital investments made since 2024 and forecast through 2031. Line 12 references capital investment assumptions discussed elsewhere, while Lines 13-24 perform the calculations of depreciation expense pursuant to Conn. Gen. Stat. §12-63(b)(6), net book value, assessed value pursuant to Conn. Gen. Stat. §12-63(a), and the eventual property tax expense by applying the composite mill rate calculated in Exhibit CLP-REVREQ-2, Schedule WP C-3.37 p17 to 21, Page 20, Line 73. The result is shown on line 24.

Lines 28-32 then summarize that result by calendar year, while Lines 38-40 summarize by rate year. After adjusting for the extent to which base rates recover the property tax related to these same investments on Line 41, as discussed in previous sections, the final property tax amount reflected in the F-Factor allowance is shown on Line 42.

f. Worksheet "PBR-6 Capital Expense Forecast"

This worksheet is provided to create the necessary link between the F-Factor revenue allowance calculations and the capital investment forecast discussed in this docket. The capital investment forecast included aligns with the Company's filed capital investment forecast, as can be seen in Exhibit CLP-ELP-1, Figure 7. The F-Factor capital investment assumptions reflected in the revenue allowance calculations of "PBR-4 F-Factor" necessarily agree with this worksheet.

g. Worksheet "PBR-7 Going-In Capital RR"

This worksheet is a collection of select data points as approved in the Company's "Going-In" rates (or, in this case, as proposed in the Company's filed cost of service schedules, Exhibit CLP-REVREQ-2-A, B, C, D Schedules, adjusted to reflect the currently authorized return on equity (9.25%) and equity capitalization (53.0%), as stated previously:

- Lines 12-16 provide the dollar amounts related to capital-driven costs of services, which are depreciation, property taxes and costs of capital. Amounts shown are currently as proposed in this illustrative model (except where noted), but ultimately will reflect the amounts as approved in this docket.
- Lines 21-28 provide a summarized view of the Company's filed rate base for the test year, rate year beginning, rate year ending, and rate year average balances. These balances serve as the basis (denominators) for establishing the capital-driven costs above as a percentage of approved balances. Those percentages are used on the other "PBR" worksheets, as well as the cost of service worksheet to estimate future costs of service based on approved levels (Lines 30-32)
- Lines 47-81 provide rates for uncollectible expense, gross earnings tax, and the costs of capital

as well as necessary calculation of gross-ups to those rates for use in the model's calculations.

- Additional details are shown in column (F) of this worksheet.

h. Worksheet "PBR-8 GDP"

This worksheet presents raw Gross Domestic Product-Price Index (GDP-PI) data obtained from the Bureau of Economic Analysis. For illustrative purposes only, this model also includes a projection of GDP-PI obtained from Moody's September 14, 2026. As noted above, actual calculations of PBR increases, if approved as filed, rely only on historical data available at the time of a given year's annual PBR filing.

i. Worksheet "PBR-9 ECI"

This worksheet contains raw Employment Cost Index (ECI) data obtained from the Bureau of Labor Statistics. Note that projections of inflation are used for analytical purposes and to assist with discussion pertaining to future rate increase implications. Calculations of PBR increases, if approved as filed, rely only on historical data available at the time of a given year's annual PBR filing.

3) Cost of Service

The cost of service included for analytical purposes in the Company's working model consists of three worksheets: "COS-1 Total," "COS-2 Capital," and "COS-3 Property Tax."

a. Worksheet "COS-1 Total"

This worksheet provides projections of the Company's actual costs through the end of the PBMRP term as a means of assessing the impact the capital investment forecast and O&M cost pressures have on the overall cost of service as well as the degree to which revenues align with the Company's cost of service (as reflected on the "Financial Summary" worksheet).

Lines 15-37 summarize the results of the cost drivers, including especially O&M (Lines 16-19), depreciation (Line 21), property taxes (Line 22), and costs of capital, including corresponding income taxes (Lines 24-27).

Gross earnings taxes and uncollectible expense are calculated on Lines 33 and 34 as if the full cost of service (Line 28) is in rates.
Non-storm O&M is shown on Lines 38-44, while storm O&M is shown on Lines 45-50, where non-catastrophic costs are identified separately from catastrophic storm / pre-staging funding.

Non-storm rate base is shown on Lines 52-59, which reflect the capital investment forecast (exclusive of AMI) filed in this docket.

Lastly, capital-driven costs of service are shown on Lines 61-67. Depreciation, property tax, uncollectible, gross earnings taxes, and costs of capital are based on the Company's filed cost of service in this docket, specifically Exhibit CLP-REVREQ-2-A, B, C, D Schedules, except that the return on equity (9.25%) and equity capitalization (53%) are shown at currently authorized amounts.

b. Worksheet "COS-2 Capital"

This worksheet functions nearly identically to "PBR-4 F-Factor" except that it relies on actual capital

investment projected over the term of the PBMRP. This is essential to understanding actual costs of service, whether or not those costs are supported by revenues. It forms the basis for evaluating the degree to which the F-Factor is sufficient. For additional details pertaining to the mechanics, please see the line references found at the end of this worksheet (or model PDF page 19).

c. Worksheet "COS-3 Property Tax"

Similarly, this worksheet is included to assist with the calculation of actual costs of service. It operates mechanically identically to "PBR-5 F-Factor Property Tax" except that it relies on actual capital investment projections (Line 12).

Date Filed: October 02, 2026

Witness:
Request from: UCONN

Question:

(Performance Based Rates) Refer to Exhibit CLP-ELP-1 at pp. 103-117 which discusses the Performance Incentive Mechanisms ("PIMs").

a. For each PIM, explain how incentive and penalty thresholds were calculated with respect to intermediate and large commercial customers served under Rates 55, 56, 57, and 58.

b. Identify whether PIMs are designed to measure or are capable of measuring service quality, reliability, or interconnection outcomes specifically for intermediate and large commercial customer classes. If class-specific performance is not tracked, explain why not.

c. Explain whether the proposed PIM penalty or incentive structure is expected to produce any direct improvement in service outcomes for intermediate and large commercial customers. If the Company contends that system-wide reliability PIMs indirectly benefit these customers, explain the basis for that contention and provide any supporting analysis.

d. Identify whether the Company considered proposing any PIM that directly measures or incentivizes service outcomes relevant to intermediate and large commercial and industrial customers, if such PIMs were considered, explain why they were not included in the Company's proposal. If no such PIMs were considered, explain why not.

e. Identify whether the Company considered proposing any PIM or performance metric that specifically measures or incentivizes service reliability or restoration outcomes for essential service consumers, including but not limited to: (i) hospitals and healthcare facilities, (ii) emergency services facilities, and (iii) water and wastewater treatment facilities. If such PIMs were considered, explain why they were not included. If they were not considered, explain why not.

Response:

a. All Performance Incentive Mechanisms (PIMs) included in the Company's PBR proposal, including targets and penalty/incentive thresholds, are calculated based on historical performance at the Company or system/enterprise level. The Company sought to identify PIMs and associated targets that support improvements in system reliability and customer service for all customer classes.

b. The proposed PIMs are not calculated for a specific rate class or subgroup of customers. The proposed System Reliability PIMs include industry-standard metrics structured to provide a proven, consistent means to assess the Company's overall reliability performance, while the Customer Reliability PIM focuses on reliability from a customer-centric perspective and seeks to assess whether all customers (regardless of customer class) are experiencing excessive multiple service interruptions or prolonged service interruptions in consecutive years. The Customer PIM Suite is designed to support continuous improvement to the overall quality of customer interactions, reinforce behaviors that contribute to a positive customer experience, and collectively reflect different aspects of the Company's service to customers to provide a more comprehensive measure of customer experience.

c. The PIM incentive and penalty structure is designed to encourage the Company to invest in a manner that cost efficiently benefits all customers through improved reliability. Reliability projects are not determined based on customer class but rather based on system needs. The customers served by the improved section of the system directly benefit from the investments.

d. Please refer to the Company's responses to subparts (a) and (b).

e. Please refer to the Company's responses to subparts (a) and (b). Although the Company does not propose a PIM related to restoration of service for specific types of customers, the Company does work with municipalities prior to and during storm events to prioritize restoration of locations designated as Critical Facilities.