Date Filed: November 03, 2026

Witness: Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP) Refer to Exhibit CLP-ELP-1 pp. 89–90 (testimony pp. 86–87). Please provide an estimated revenue requirement forecast under the Company's proposal if all Performance-Based Multi-year Rate Plan ("PBMRP") components are implemented at the Company's forecasted levels and assumptions. The analysis should include a cost recovery break-out for each PBMRP component or subcomponent if the mechanism contemplates multiple expense types. Provide a brief discussion of the calculations and assumptions used or note where support for certain forecasted components have been previously provided (e.g., Response to EOE-156).

Response:

The Company's proposed Performance-Based Multi-Year Rate Plan ("PBMRP") is designed to balance several objectives over the multi-year stay-out period: greater predictability and a smoother progression of customer rate changes, incentivizing for cost efficiency by the Company over the course of the PBMRP, accountability for costs and performance, and sufficient revenue support for the costs of infrastructure investments necessary to provide safe and reliable electric distribution service over the term of the rate plan. That balance begins with an appropriate going-in revenue requirement. The PBMRP then establishes a disciplined framework for how revenues change from that starting point over the multi-year period. As explained in the Company's response to interrogatory EOE-156[i], the stay-out period is itself an important source of the efficiency incentive because the Company bears the risk that its actual costs will deviate from the revenues produced by the plan.

The PBMRP is structured around complementary mechanisms recognizing the different drivers of utility costs. The I-X-CD mechanism addresses operating-cost pressures through inflation, adjusted by a productivity factor and Consumer Dividend to enhance incentives to operate efficiently. The F-Factor provides revenue support for necessary capital investment, subject to a cap based on the approved capital forecast and downward-only reconciliation. The exogenous mechanism addresses unforeseen material cost increases or decreases that qualify for exogenous treatment under specific circumstances. Meaningful customer guardrails include the F-Factor investment cap and downward-only reconciliation, the 5 percent I-X cap, and the Earnings Sharing Mechanism ("ESM"). The Company's intent was to develop a regulatory framework intended to be sustainable while balancing the objectives described above, and being mindful of positions taken in PURA's PBR dockets up until this point.

The forecasted revenue increases under the PBMRP after Rate Year 1 are $77.6 million effective July 1, 2028, $81.1 million effective July 1, 2029, and $83.0 million effective July 1, 2030. These amounts are provided in the Company's response to interrogatory EOE-156, Attachment 1, worksheet "PBR-1 Total PBRA," Line 41. That attachment provides the underlying calculations, while the response to EOE-156 provides detailed discussion of the calculations and assumptions, including the I-X-CD and F-Factor calculations and how those components combine to determine the forecasted PBRA as proposed in this proceeding, adjusted to reflect PURA's currently authorized capital structure and ROE for illustrative purposes. Importantly, that discussion also evaluates the framework outlined in PURA's draft RE01 decision and the adaptations incorporated in the Company's PBMRP proposal to make that framework viable for Connecticut stakeholders.

The Company's proposal starts with an appropriate going-in revenue requirement and establishes a transparent framework that limits and smooths subsequent adjustments, rewards efficiency, protects customers when costs or investment are lower than forecast, and/or if rates inadvertently produce returns above the authorized ROE, and provides defined mechanisms for necessary investment and unforeseen events. If PURA decides in this proceeding to not implement the PBMRP, such a decision will not eliminate subsequent rate increases for customers but instead will change when and how those rate changes impact customers. As illustrated in the Company's response to EOE-156 and AMTRAK-12, Attachment 1, the PBMRP produces forecasted annual total-bill increases of approximately 1.5 percent for the 2028 through 2030 adjustments, compared with larger individual increases under a rolling rate-case cycle framework. The PBMRP is designed to address those same underlying cost pressures in a more disciplined way: with greater visibility, more gradual rate changes, meaningful customer protections, and strong incentives for the Company to manage efficiently between rate cases. That is the practical balance the Company's proposal is designed to achieve.

Prior Referenced Response:

[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.

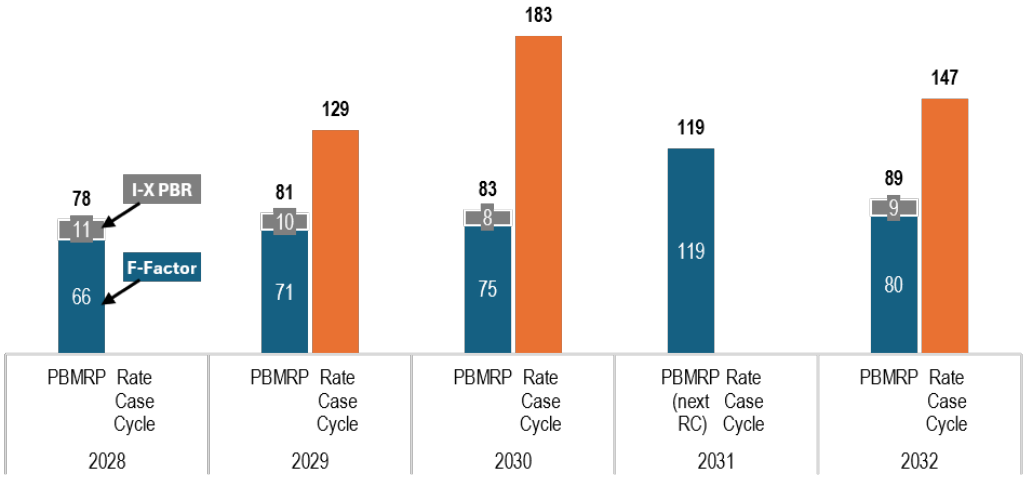
In a world in which system investment needs are relatively flat, economy-wide inflation is modest and predictable at 2% annually, and rates are fully coupled with growing sales revenues (and no revenue decoupling mechanism), it is conceivable that a utility could offset the cost increases it incurs with 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.

Results of F-Factor Implementation Assuming Capped Forecast Investment

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.

A. 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-Bar1 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.

   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.

3. **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.

4. **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.

5. **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 PBMRP2, 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) Financial Summary

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 18 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 F-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 27, 2026

Witness: Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP) Refer to Exhibit CLP-ELP-1 pp. p. 102. Please clarify the Company's statement that "Any such investment would instead remain subject to review and consideration in a subsequent base rate proceeding or successor PBMRP Term."

Response:

The quoted statement addresses capital additions above the Forecasted Budget cap established for recovery through the F-Factor during the PBMRP term. Under the Company's proposal, investments during the PBMRP that exceed the plant additions cap would not be eligible for F-Factor recovery during the initial PBMRP term and would remain subject to the prudence review and regulatory process typically applicable when rates are next set.

As explained in the Company's responses to OCC-423[i] and OCC-426[ii], at a subsequent base-rate proceeding or successor PBMRP term, qualifying plant additions would be considered for inclusion in rate base at their then-applicable net plant, or depreciated, value and would remain subject to prudence review. There is no special or guaranteed recovery for amounts above the F-Factor cap. Thus, the financial effect of exceeding the cap is real. The Company bears the carrying costs and unrecovered depreciation associated with those investments unless and until the investments are subsequently reviewed and approved for recovery.

Prior Referenced Responses:

[i] OCC-423 Question:

Exhibit CLP-ELP-1 Please explain in detail why the Company believes its proposed treatment of capital expenditures under the PBMRP, including the use of forecasted capital expenditures and the F-Factor, is preferable to including capital expenditures within the Revenue Cap Formula framework as proposed in the Docket No. 21-05-15RE01 Proposed Final Decision. In your response,

a. Please explain why the Company believes O&M expenses are appropriately subject to an externally indexed revenue cap, while capital expenditures require separate recovery through an F-Factor based on a fixed annual capital investment forecast.
b. Please explain how the Company's proposed treatment of capital expenditures is expected to produce customer cost savings or otherwise improve customer affordability relative to including capital expenditures within a revenue cap formula.

c. Please explain how the proposed F-Factor mitigates or avoids any incentive to favor capital expenditures over O&M solutions, including in circumstances where either a capital or O&M solution could be used to address the same system need.

OCC-423 Response:

The Company appreciates OCC's thoughtful and analytical questions on the Company's proposed performance based multi-year rate plan ("PBMRP") and looks forward to further discussion on the development of a workable PBR framework for the Company's customers.

To cover the issues raised in the question, the Company's response is organized as follows:

1. Review of relevant aspects of the Company's PBMRP.
2. Considerations on the design of capital-driven revenue support.
3. Specific responses to parts (a), (b) and (c), above.

1. Review of the Relevant Aspects of the Company's PBMRP

Ultimately, the Company's goal in this proceeding is to establish a sustainable, cohesive ratemaking framework that advances 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 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.

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.

For any multi-year rate plan to be successful, it needs to be grounded in the reality of the utility's costs, while also incorporating features that innately push the utility to be more efficient. That is not to say every dollar of the utility's costs will be (or should be) recovered. Rather, the allowed revenues need to be sufficient to afford the utility a reasonable opportunity to cover its cost of service to customers, including a reasonable rate of return on equity ("ROE") where the utility is operating prudently and efficiently, as required by state law. A framework in which the utility has *no* reasonable opportunity to earn its ROE, regardless of how hard it strives for efficiency, simply becomes self-defeating because the utility will exercise its statutory rights to a distribution rate proceeding, thereby muting the most powerful efficiency feature of a multi-year rate plan, which is the stay-out term.

A framework that underestimates the actual cost to run the system and/or affords the utility no reasonable chance to earn its allowed ROE, year after year, also results in under-investment and a system that not only lacks innovation, but falls further and further behind at a significant – albeit potentially unseen – cost to customers. As a result, a lasting, productive framework is one that is soundly informed by – not detached from – the drivers of the utility's real cost of service, including its cost of capital.

In this context, the two most critical features of the Company's PBMRP are as follows:

- A going-in revenue requirement that reasonably reflects the Company's actual operating expenses and cost of investment in the Rate Year, so that through effective management and prudent decision making, the Company can achieve the true efficiency gains that will be needed to stretch the approved revenue requirement over the stay-out term. Without a reasonable opportunity to maintain financial integrity over a stay-out period, as measured by the authorized ROE, the utility cannot focus on innovation and efficiency gains – and will instead file for the next rate case to make up ground. To accomplish this goal, the overall paradigm must "hang" together, making the base revenue requirement a pivotal element. The many components of a PBR plan, including going-in rates, as well as the subsequent rate adjustments, must work in concert with performance objectives and the capital investment requirements expected of the Company – for the benefit of customers, i.e., the entire framework must work to the benefit of customers, not only in relation to the price they will pay, but also in relation to supporting the level of service that they need and expect.
- Revenue support for incremental capital investment to support long-term system goals. The Company operates in a capital-intensive industry and has a substantial need to acquire cash on a systematic basis to operate its business. As annual capital investments regularly exceed net cash from operations (i.e. cash receipts from customers net of operating cash outflows), the Company must look to other capital sources to fund those investments. Those sources are the debt and equity investors supplying the cash to capital markets. This means the Company must compete with all other entities participating in those markets to attract capital. It is simply not possible for the Company to go to those markets and demand cash for free, or at below-market rates relative to the investor's risk when other entities participating in the same capital markets offer compensation for the use of funds over time.

  The Company provided extensive analysis and discussion on the cost of capital throughout Docket No. 21-05-15RE01, including specifically as it relates to CT-Bar. PURA's treatment with respect to going-in revenue requirements as well as any ongoing capital-driven revenue support mechanism, such as CT-Bar, is paramount to whether the Company, with effective management and sound decision-making, can responsibly cede its right to file for a rate amendment, whereas that is otherwise the only tool the utility has to align its revenues and costs and have a reasonable chance at earning its authorized ROE, which, over time, is necessary in order to attract the capital necessary to meet the standards of service expected of the Company's customers.

  The lack of a valid revenue requirement component within the CT-Bar that would allow recovery of the cost of capital associated with incremental capital investment over the term of the PBMRP is a non-starter from a policy perspective, creating an obstacle that would block a utility from giving up its right to file for rate modifications over the multi-year period in question. This is particularly accurate in the present environment in which significant increases in the level of necessary system investments are expected (and planned). Simply put, the CT-Bar, as previously envisioned in PURA's draft PBR decision, fully prevented the Company from having any practical chance at staying out of a rate case, and therefore, would never work to create a reasonable PBR framework.

  The Company's proposed PBMRP in this docket is designed to track the design of the CT-Bar as closely as possible, given that this was PURA's developing framework. However, the Company's PBMRP addresses the two primary faults in PURA's RE01 framework that would prevent the implementation of a workable PBR framework, which are (1) the deviations from ratemaking fundamentals that grossly understate the "going in" revenue requirement; and (2) modification of the CT-Bar to reflect the revenue requirement applicable to capital investment, which would include recovery of the cost of capital and the cost of removal over the course of the PBMRP term. The Company's F-Factor also corrects for the mechanical error of deducting depreciation expense from new plant additions, rather than from rate base.

In particular, the Company's proposed F-Factor is designed to recover no more than the revenue necessary to support a discrete amount of ongoing system investment, recognizing that the cost of capital is a lawful and factual cost of service that must be incorporated into the revenue requirement calculation for the Company, as it is for any utility.

2. Considerations on the Design of Capital Driven Revenue Support

CT-Bar, as defined in PURA's Proposed Final Decision, issued in Docket No. 21-05-15RE01, on July 14, 2025 (the "RE01-PFD"), had several sensible qualities that the Company supported. However, those "sensible" qualities were overcome by certain critically flawed concepts that would need to be modified or eliminated in order for the Company to consider committing to a stay-out. The positive and negative CT-Bar qualities are outlined briefly here and discussed in greater detail below, including with respect to similarities or differences to the Company's proposed F-Factor.

Summary of constructive features of PURA's RE01-PFD:

1) Acknowledgement that current revenue support for ongoing investment is essential;
2) No category of capital investment was summarily or preemptively excluded from CT-Bar;
3) CT-Bar takes effect with Rate Year 1; and
4) CT-Bar aligns capital revenue support with the capital investments of the DSP.

Summary of unworkable features of PURA's RE01-PFD:

1) Exclusion of the recognition in the CT-Bar of the cost of capital between rate cases.
2) Exclusion of cost of removal in the CT-Bar.
3) Application of depreciation expense as a reduction to plant additions rather than rate base.

Constructive features of PURA's RE01-PFD:

1) Positive #1: Acknowledgement that current revenue support for *ongoing* investment is essential to the integrity of the PBR framework.

First, that the CT-Bar even existed in PURA's RE01-PFD is genuine acknowledgement that some form of revenue support for Rate Year investment is essential to support a PBR framework. As discussed at length in that docket, the Company anticipates significant system investment over the next five years to advance the state's clean energy and reliability goals. Revenue support for *ongoing* system investment is crucial for any multi-year rate plan, whether in the form of the Company's proposed PBMRP, step increases, or any other ratemaking framework. CT-Bar's inclusion in RE01-PFD is a clear indication that incremental revenue support for ongoing system investments is a necessity.

2) Positive #2: No category of capital investment was summarily or preemptively excluded from CT-Bar.

Second, the RE01-PFD did not exclude particular categories of capital investment. For example, capital investments in facilities, fleet and information technology are viewed as permissible categories for revenue support in the CT-Bar framework. This is consistent with the Company's proposed F-Factor in this proceeding.

3) Positive #3: CT-Bar takes effect as of Month 1 of Rate Year 1.

The Company provided extensive discussion and analysis throughout Docket No. 21-05-15RE01 technical sessions and data responses regarding the "going-in" revenue requirement and the detrimental financial consequences of limiting capital investments to a period of time removed from the Rate Year. Ignoring for a moment the CT-Bar's deficiencies, having the mechanism take effect Month 1 of Rate Year 1 minimizes or eliminates those detrimental timing consequences, particularly in light of the fact that PURA has in recent years moved away from its prior practice of implementing future-test years in base rate proceedings, instead favoring a strict historical Test Year practice as it relates to plant additions.

Revenue decoupling is a factor to consider here because the revenue decoupling mechanism ("RDM") subsumes all sales growth to the extent that it is occurring, funneling incremental sales revenues back to customers. RDM is supported by valid policy reasons; however, the fact is that there are capital costs associated with adding new customers. Historically, when consistent and steady levels in the range of ~3$ per year of annual growth in sales and revenues was available to a utility to help offset the cost of incremental capital additions between rate cases, the pressing need for incremental revenue support was mitigated. Without the ability to capture that sales growth, and combined with the absence of an ongoing revenue support mechanism such as an F Factor taking effect on Month 1 of Rate Year 1, the Company would not be in a position to commit to a stay-out of any duration. This is because the Company would never be in a position to cover its cost of service (inclusive of its authorized cost of capital) because its rates would be set on a historical level of plant additions, despite the fact that its capital expenditures are higher than historical levels of depreciation, and because revenue decoupling ensures that even if load growth exists (and even if such load growth is enabled by the Company's increased level of capital expenditures) the Company is unable to retain additional revenues contributed by new customers, or new load.

4) <u>Positive #4</u>: CT-Bar was designed to align capital revenue support with the DSP.

Ignoring its deficiencies, the CT-Bar's connection to the Distribution System Plan ("DSP") constituted an essential link between ongoing system investments necessary to meet the objectives of the DSP with the revenues necessary to support those investments. Throughout Docket No. 21-05-15RE01, the Company advocated strongly for clearly defined linkages across all three tracks (RE01, RE02 and RE03), including proposing what would be the final technical session touching upon revenue requirements, in which those linkages were discussed. The Company's F-Factor is similarly aligned with the capital investment forecast provided in this proceeding for the DSP. The Company's capital investment forecast serves as the basis for a cap on the level of investment for the F-Factor.

<u>Unworkable Features of PURA's RE01-PFD:</u>

1) <u>Negative #1</u>: No recovery of cost of capital in the revenue requirement for capital investment between rate cases.

The single-most problematic feature of the CT-Bar was its intentional exclusion of the cost of capital associated with completing capital plant additions to the benefit of customers. Costs of capital are real costs of providing electric distribution service to customers in the State of Connecticut (or anywhere) and are recognized in statute. Although the cost of capital may be a more challenging cost to conceptualize, it is nonetheless as real as vegetation management, insurance, customer service, or any other cost of service. Cash is not free, a fact arising from its scarcity. Fundamentally, capital markets are where people, banks, corporations and other institutions provide their surplus of cash -- which is limited, to those entities that have cash needs -- which are generally unlimited. Consequently, and unsurprisingly, those entities providing the cash for some period of time expect to be compensated for providing it, thus

establishing real cost to acquire capital.

The Company, operating in the capital-intensive industry of regulated utilities, is one of those entities that needs to acquire cash to operate its business. As annual capital investments regularly exceed its net cash from operations (i.e. cash from customers), the Company must look to other sources to fund those investments. Those sources are the debt and equity investors supplying the cash to capital markets. This means the Company must compete with ALL other entities participating in those markets. It is simply not possible for the Company to go to those markets and demand cash for free (or for below-market rates, relative to market expectations of risk and reward) when other entities participating in those capital markets offer adequate compensation for the use of funds over time. Therefore, there is a real and tangible cost to acquiring that capital. Please refer to the Company's pre-filed cost of capital testimony for in-depth discussion of the cost of capital.

The Company provided extensive analysis and discussion on the cost of capital throughout Docket No. 21-05-15RE01, including specifically as it relates to CT-Bar. PURA's treatment with respect to going-in revenue requirements as well as any ongoing capital revenue support mechanism, such as CT-Bar, is paramount to whether the Company, with effective management and sound decision-making, has the opportunity, but not a guarantee, to cover its cost of service to customers, and to earn its allowed return. The absence of the cost of capital from the CT-Bar, particularly in the present environment where significant increases in the level of necessary system investments are expected, prevents the Company from having any practical opportunity to commit to a stay-out to avoid the next rate case.

As discussed in the Company's response to OCC-435, based on the Company's current assessment of system investment needs in the near future, the revenue requirement associated exclusively with the cost of capital pertaining to future capital additions (*excluding* GET and Uncollectible) would amount to an incremental $15.6 million for Rate Year 1; an incremental $32.8 million for Rate Year 2; an incremental $36.4 million for Rate Year 3; and an incremental $39.5 million for Rate Year 4, or $124.1 million in total.

This means that -- even if 100% of those future plant additions were only partially supported with CT-Bar revenues (i.e. revenue covering depreciation expense and property taxes only); and even if the Company's future cost of service otherwise was 100% supported with rates; and even with perfect operational decision making -- the Company would still need to find $124.1 million of *annual* savings by Rate Year 4 in order to offset the loss of revenue associated with carrying costs on incremental investment over the term of the PBMRP, which would be necessary to commit to a stay-out term.

For perspective, the total O&M expense included in the Company's cost of service filed in this proceeding is $547.5 million. Thus, to earn its authorized ROE, all else equal, the Company would have to generate cost savings amounting to $124.1 million, or nearly 23%, of its Rate Year O&M level by Year 4, to offset the impact of the accumulating carrying costs on the incremental capital additions completed on the system *after* base rates are set in this case. This is nearly 34% of operating expense, excluding vegetation management and storm restoration costs, which is a very substantial proportion of the cost of service.

For example, the amount of $124M is nearly two-thirds of the Company's labor and labor-related operating expense, or 60% more than the entire vegetation management program. It simply is not possible for the Company to cut this level of O&M expense without grossly debilitating the Company's ability to provide service to customers. In fact, it is not plausible to expect that the Company could generate even 10% in annual incremental O&M savings in the face of 2-3% annual inflation and, as a result, the Company could not agree to a stay out under circumstances where there is no recovery of the

cost of capital on incremental investment over the PBMRP term.

Moreover, even if the Company were somehow able to find such remarkable cost savings, the going-in revenue requirement of the subsequent multi-year rate plan would capture those cost savings. Assuming continuation of the same PBR framework and required system investment, the Company would again be in the position of having to find an additional 34% of O&M savings (i.e. more than 60% cumulatively from Rate Year 1) in order to sustain itself over the next PBR term. Clearly, a framework that does not provide revenue supporting the full cost of incremental investment over a four-year period, as well as the next four-year period, is not a plausible or lasting framework. Thus, exclusion of the cost of capital from a capital support mechanism in an environment in which significant increases in capital investments are expected all but ensures the Company has no realistic opportunity to survive the PBR term without a critical need for a rate case to realign costs and rates. Consequently, the overall framework as outlined in the REO1-PFD had no practical chance of sustaining the Company financially for the four-year term, nor would the Company have been able to even agree to a stay-out.

To address this indelible flaw, the Company's proposed PBMRP in this docket is designed to produce the revenue necessary to support ongoing system investment through the F-Factor, which calculates a revenue requirement inclusive of the costs of capital unlike the CT-Bar, while preserving the customer benefits and inherent incentives of a PBR plan.

2) **Negative #2: Exclusion of cost of removal from the revenue requirement on capital investment between rate cases.**

CT-Bar excluded the cost of removal, which is a real cost for all utilities. As a simple example, to install a new utility pole where there is an existing one that needs replacement, the Company must first remove the existing utility pole. That cost is separate and distinct from the cost of the utility pole itself; yet, similarly recovered (as an estimate) over the life a utility pole. The Company's capital investment forecast in the present docket includes approximately $136 million of cost of removal for January 1, 2026 through June 30, 2028, and approximately $60-70 million per year thereafter. A total of $60-70 million in annual investment equates to pre-tax cost of capital of $6-7 million annual *incremental* revenue requirement (e.g. $6 million year 1, $12 million year 2, $18 million year 3, etc.). The CT-Bar revenue requirement intentionally excluded this component of the capital investment revenue requirement. The Company's proposed F-Factor calculation properly restores this component to the rate base computation.

3) **Negative #3: Depreciation expense is used as a reduction to plant additions rather than to total rate base, consistent with fundamental ratemaking principles.**

CT-Bar's calculation treats depreciation expense as a net against plant additions. Although the Company appreciated that PURA found it important to capture ongoing depreciation expense in the annual revenue requirement calculations, the overall execution of the computation was not correct. The Company's F-Factor corrects for this methodological error. Please refer to the example below outlining the mathematical problem:
($ Millions)

		($ Millions)				
1	Correct treatment of depreciation's accumulation in rate base					
2		Rate Base			RevReq	
3		Year 1	Year 2		Year 1	Year 2
4	Plant Additions	$1,000	$1,000			
5	Cumulative Gross Plant	$1,000	$2,000	x 3.6% Depreciation	$36.0	$72.0
6	Accumulated Depreciation	-$300	-$600			
7	Cumulative Rate Base	$700	$1,400	x 9.8% Cost of Capital	$68.6	$137.2
8				Total Revenue Requirement	$104.6	$209.2
9						
10	CT Bar					
11		Rate Base			RevReq	
12		Year 1	Year 2		Year 1	Year 2
13	Plant Additions	$1,000	$1,000			
14	Depreciation Expense	-$300	-$300			
15	Net Plant Additions	$700	$700			
16	Cumulative Depreciable Base	$700	$1,400	x 3.6% Depreciation	$25.2	$50.4
17	Cumulative Rate Base	$700	$1,400	x 9.8% Cost of Capital	$68.6	$137.2
18				Total Revenue Requirement	$93.8	$187.6
18				Error	-$10.8	-$21.6

The table above is a simplified example of CT-Bar's improper incorporation of ongoing depreciation in a revenue-requirement calculation. Effectively, the CT-Bar reduces plant additions by depreciation expense, which improperly reduces the total amount of plant to be depreciated, thereby reducing the incremental depreciation expense to be supported by the rate mechanism. The correct approach is to handle the plant additions separately from accumulated depreciation (see lines 4 and 6 in the table above). Note that both methods result in the same return on rate base, demonstrating that both calculations reflect the reduction to return on rate base resulting from ongoing/accumulating depreciation. The error is limited to the resulting new depreciation expense reflected in the revenue requirement, which is understated in the above example by $10.8 million in Year 1 and $21.6 million in Year 2 under the CT-Bar as compared to the Company's proposal in this proceeding, which mirrors in concept to how the Company records depreciation expense on gross plant additions (not on net plant additions, as in the CT-Bar).

Characteristics of the Company's Proposed F-Factor (same as CT-Bar, except for three features).

The Company is proposing a capital support mechanism (the "F" factor in the formula) that tracks as close as possible to PURA's CT-Bar, except that it addresses the three major impairments described above, which would prevent the Company from being able to agree to a stay-out. These three items are the exclusion of the cost of capital in the revenue-requirement computation for incremental plant additions, the cost of removal and the mechanical deduction of depreciation expense from plant additions instead of rate base. In the Company's F-Factor, these first two items are included in the formula and the third mechanical process is addressed.

Beyond that, the F Factor would operate from a fixed annual capital investment level for each year of the PBMRP, with reconciliation through PURA's annual RAM proceedings. The fixed annual investment level would be set at the Company's capital forecast, as approved in this proceeding. As described previously, the Company has presented different investment trajectories in the Company's 5-Year TSP and is proposing to establish the capital support mechanism of the PBR adjustment consistent with the annual capital funding requirements presented in Figure 7 of Exhibit CLP-ELP-1.

Consistent with the structure of the CT-Bar in the RE01-PFD, the F-Factor would commence on July 1, 2027, coincident with new base rates, collecting an allowance developed from the Company's capital forecast presented in

Exhibit CLP-TSP-3. In this proceeding, the Company has proposed base rates that include capital additions through the Rate Year. This means that the F-Factor implemented on July 1, 2027 (commensurate with new rates in this proceeding) would be set to zero at that time, since base rates would be set to collect the revenue requirement on capital placed into service in the Rate Year.

However, if PURA declines to incorporate rate-year capital additions into base rates in this proceeding, the F-Factor taking effect on July 1, 2027, would reflect the revenue requirement for the period July 1, 2027 through June 30, 2028 on capital additions placed in service (or estimated to be placed in service) from the point in time where PURA cuts off capital for inclusion in base rates and through June 30, 2028.1 In the next year, as part of the Company's annual RAM compliance filing, actual plant additions placed in service during the applicable plan year would be reconciled against the F-Factor allowance put into rates on July 1, 2027. In that reconciliation, the Company would present its project document for a prudence review and, based on PURA's findings in that prudence review, the cost of actual plant additions for calendar year 2027, less whatever PURA has already included in rates for capital additions in 2027, would be actually incorporated into rate base at that point. Following PURA's determination that the Company's actual plant additions are prudent, used and useful, the Company's rate base would be adjusted and associated revenue requirement allowed for recovery that would be limited to the lesser of:

1. The total revenue requirement for the forecasted capital approved in this proceeding for the first implementation of the F Factor; or
2. The total revenue requirement for the actual plant in service.

If the cost of the Company's actual capital additions were to exceed the forecasted amount approved in this proceeding, the Company would not be permitted to obtain recovery of the incremental investment during the initial four-year PBMRP Term. Instead, any such investment would remain subject to review and consideration in a subsequent base rate proceeding or successor PBMRP Term.

This Company's proposed capital funding mechanism sets a defined cap on capital recovery during the plan term, providing customers with greater rate certainty and placing the risk of excess capital spending requirements on the Company. The annual reconciliation further protects customers by blocking recovery of investments that are delayed, deferred, canceled, or not placed in service, since those costs would not be reflected in the F factor, which is based on plant in service. For these reasons, the proposal aligns cost recovery with prudent investment, promotes accurate capital forecasting, and incentivizes efficient execution of the capital program, all while preventing customer over-collection.

III. Specific Responses to Parts (a), (b) and (c), above.

(a) Why are O&M expenses appropriately subject to an externally indexed revenue cap, while capital expenditures require separate recovery through an F-Factor based on a fixed annual capital investment forecast?

The capital investments the Company must make to provide electric service to customers in the State of Connecticut is a "local" concept. Those investments are driven by the circumstances and objectives of the State of Connecticut and the history and current status of the distribution grid in Connecticut. Those circumstances and objectives, which require long-term system planning and appropriate capital resources, are not encapsulated by a single index. O&M, though it is similarly influenced by local circumstances, does not change at the same rate as capital investment. For example, the Company's annual capital investment is expected to increase nearly 40% from $549 million in 2025 to $758 million by 2028, or more than 11% annually, on average. In contrast, over the same timeframe O&M (excluding storm funding and vegetation management) is projected to increase approximately 3-4% annually. The

Company's proposed PBMRP aligns revenues with drivers of cost while maintaining the incentive to control costs.

In addition, under PBR theory, where capital inputs are contemplated in the indexed formula, then the X factor is negative, implying that the annual adjustment is inflation plus an additional factor. The testimony of London Economics in Exhibit CLP-PBR-1 reviews the results of their total factor productivity study producing this result. In this case, the Company elected to adhere as closely as possible to PURA's (draft) CT-Bar in order to remain synched with PURA's policy direction.

(b) How will the Company's proposed treatment of capital expenditures be expected to produce customer cost savings or otherwise improve customer affordability relative to including capital expenditures within a revenue cap formula.

There are three main opportunities for customer benefit in the PBR framework, which are: (1) the opportunity to leverage the stay-out term to drive operational efficiency and cost savings; (2) the opportunity to spread rate changes out over time to smooth impacts for customers and employ the concept of gradualism rather than promoting the cost and inefficiency of a traditional rate-case cycle; and (2) the opportunity to develop a systematic investment plan that promotes operational efficiency and cost-saving procurement strategies, while taking advantage of the smoothing impacts of the PBR framework to mitigate cost impacts.

The Company has submitted substantial testimony and documentation in this proceeding to provide insight into the level of capital investment that is needed on the system to provide adequate service to customers and to support the economic vitality of the State of Connecticut. Customers benefit directly when investment can be undertaken on a planned, systematic and consistent basis over time because (1) it is consistently more expensive to complete infrastructure projects tomorrow rather than today due to price inflation and other factors; and (2) the Company's process inputs (i.e., primarily labor and materials) cost less when procured on a planned and systematic basis rather than on an emergent basis.

Although difficult to define in terms of the overall cost trends, there are significant benefits for customers in an operating approach that is consistent, systematic, planned and carefully managed, which is an outcome that the Company is hoping to promote with its proposals in this proceeding. Bottomline – the Company is looking to establish a ratemaking framework that will promote efficiency of operations for the benefit of customers and the F-Factor is the optimal mechanism for that purpose.

Assuming that OCC's referenced alternative for a capital-cost mechanism "within a revenue cap formula," means that the PBMRP would rely exclusively on an "I-X" revenue cap formula, with or without X defined with a negative factor, the Company's experience is that it is not adequate to support necessary capital investment, while raising issues for stakeholders. With the negative X factor, there is no direct link between the actual cost of capital plant additions and the revenue collection through customer rates, leaving it to be insufficient to support necessary capital investments and unsatisfactory for stakeholders that want transparency between the costs collected in rates and the rates that customers pay. As a result, achieving the efficiency needed to support a cost-effective capital plan is illusory in this model.

(c) How does the proposed F-Factor mitigate or avoid any incentive to favor capital expenditures over O&M solutions, including in circumstances where either a capital or O&M solution could be used to address the same system need?

In the Company's experience, implementation of the X factor mechanism (with a negative X factor) to cover capital investment was thought to be a mechanism that would promote efficient solutions between capital and O&M because the revenue allowance was not predicated on actual plant additions; rather, was simply formulaic. In 2017, the Massachusetts Department of Public Utilities ("MDPU") approved a negative X factor within a revenue cap for NSTAR Electric Company d/b/a Eversource Energy – and it remained operative for the five-year term of the plan. However, the fact is that – during an extended stay-out period, there is no incentive to incur any greater level of expense than is absolutely necessary to run the business. Therefore, there is no greater impetus than would exist in any event to make the optimal choice between expense and capitalization, where such a choice exists. And again, with the negative X factor, the MDPU felt it had no line of sight as to whether funds allowed to NSTAR Electric through the annual PBR allowance were, indeed, being leveraged for system investment.

Therefore, in 2022, the MDPU instituted the K-Bar providing an allowance for system infrastructure projects, coupled with reporting requirements on investment levels. The MDPU maintained the I-X formula to cover the O&M portion of the approved revenue requirement, which is what the Company is proposing in this case.

In reality, there are very few instances when system needs can be easily transitioned between a capital-work solution or a work solution that can be expense. The prudence review is the primary and most effective tool that regulators possess for evaluating these situations.

[ii] OCC-426 Question:

Exhibit CLP-ELP-1 Please describe how the proposed process for recovering incremental investments in a subsequent base rate proceeding or successor PBMRP Term if actual capital spending exceeds the forecasted amount will support utility cost containment. Please describe the Company's proposed process for review of excess incremental investments in a subsequent base rate proceeding or successor PBMRP term.

OCC-426 Response:

For clarity, the Company does not expect to recover "actual capital spending [that] exceeds the forecasted amount …" (emphasis added). The Company is requesting to recover the costs of actual plant additions that are used and useful for customers, not "capital spending," which the Company views as an important point because this is how ratemaking works, i.e., plant additions that are used and useful and are not yet included in rates, are then recoverable in the next base-rate proceeding. The purpose of a capital cost recovery allowance during the PBMRP is to provide a level of revenue support during a stay-out period as part of the integrated set of incentives inherent in a PBR framework.

Further, a cost-recovery framework that, by design, cuts-off any recovery of the costs of actual plant additions that are necessarily incurred for the purpose of providing electric service and are used and useful for customers (i.e., a flat disallowance without a prudence review) would violate legal principles and would likely have the effect of simply discouraging the overall level of investment to begin with.

The Company's proposal for capital cost recovery is designed to provide revenue support for a set amount of actual plant additions during the PBR term, creating a "stretch" incentive to the extent that actual plant additions exceed the allowance established by the PBR plan. With capped recovery of the cost of actual plant additions, the inherent incentive is to control capital costs rigorously because only plant additions up to the cap will be eligible for recovery during the PBR term. Lagged recovery will apply to the capital additions completed above the cap and recovery will not occur until the next time rates are set (after the stay-out term), creating downward financial pressure on the Company to carry those completed investments until the next rate case. For example, with the stay-out applicable

under the PBR plan, plant additions in excess of the capped amount will continue to depreciate, creating real loss for the Company through unrecovered depreciation expense and a lower net book value added to rate base in the next rate case.

In addition, at the time of the next rate case or successor PBMRP term, the Company's plant additions will be subject to a prudence review before being allowed to be included in rate case, consistent with ratemaking practice. There would be no special treatment for those plant additions. The plant additions would be included in rate base, subject to the prudence review, at the net plant (depreciated) value applying at that point.

Thus, the Company is not proposing to change the manner in which those investments are reviewed for prudence as part of a general rate case proceeding or successor PBMRP term, other than the fact that the Company anticipates that if the Company's proposed PBMRP is adopted in this proceeding, PURA may elect to conduct prudence reviews of capital additions during the pendency of the PBMRP term rather than waiting until the next rate case to conduct such a review. However, this does not change the fact that the Company will still be incentivized to contain its costs to the greatest extent possible during the PBMRP.

Please note that the Company's core capital investment forecast provided in this proceeding does not include amounts necessary to support Advanced Metering Infrastructure (AMI). The capital investment supported by the Company's proposed F-Factor would need to be modified to include amounts for AMI, if AMI is ultimately approved.

Date Filed: October 27, 2026

Witness: Donald J. Scacco Jr., Digaunto Chatterjee and Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP) Refer to Exhibit CLP-ELP-1 at p. 65. Refer to Figure 7 CL&P Capital Funding Requirements (2027-2031). Please explain whether the Company proposes to cap the capital cost recovery mechanism at the TSP Plan capital funding requirements by major expenditure category or the total.

Response:

The Company proposes that the capital investment forecast operate as an aggregate cap on capital investment eligible for recovery through the F-Factor, not as separate caps by the major expenditure categories shown in Figure 7. Figure 7 identifies the major categories comprising the Company's capital funding requirements, but the F-Factor reconciliation measures cumulative actual capital additions against the cumulative Forecasted Budget in the aggregate.

Consistent with EOE-156[i] and the Company's response to OCC-436[ii], actual capital additions are subject to a downward-only reconciliation. If cumulative actual capital investment is below the approved Forecasted Budget, the F-Factor is reconciled downward. If cumulative actual capital investment exceeds the Forecasted Budget, the F-Factor is not increased above the cap. Separate treatment would apply where PURA expressly approves investment outside the presently filed capital forecast, such as AMI, for which the Company has proposed that the forecasted budget caps be adjusted if the program is approved.

Prior Referenced Responses:

[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.

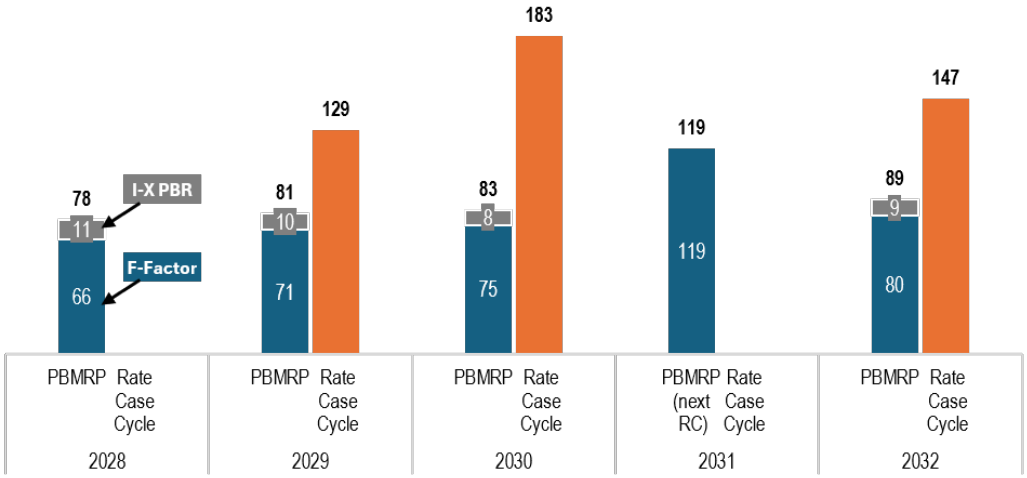
Results of F-Factor Implementation Assuming Capped Forecast Investment

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-Bar1 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 PBMRP2, 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) Financial Summary

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 18 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 F-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,

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).

[ii] OCC-436 Question:

Exhibit CLP-RATES-3 Please clarify whether, in any Rate Year, the Company may recover the revenue requirement in excess of the Forecasted Budget amount included in the F-Factor allowance for that Rate Year that may result from capital additions placed in service in a prior year that have not yet been reflected in base rates. In your response, please:

a. Explain the circumstances under which F-Factor recovery may exceed the Forecasted Budget amount for the applicable Rate Year;
b. Explain how the revenue requirement associated with prior-year capital additions is calculated and incorporated into the F-Factor;
c. Explain whether such prior-year capital additions are subject to the same annual downward-only reconciliation and Forecasted Budget cap as capital additions placed in service during the applicable Rate Year;
d. Explain how recovery of prior-year capital additions is consistent with the Company's characterization of the Forecasted Budget as a cap on capital recovery during the PBMRP term; and
e. Explain how this treatment supports the Company's stated customer affordability and rate-stability objectives and preserves the customer protections associated with the downward-only reconciliation.

OCC-436 Response:

Please refer to the Company's responses below. Please also refer to the Company's response to interrogatories OCC-423 and OCC-426.

a. The Company has not proposed any flexibility with respect to the capital investment that would be permitted to be recovered via the proposed F-Factor. That is, the capital investment forecast provided in this proceeding would serve as a hard cap of the core capital investment eligible for the F-Factor. Incremental capital investment programs mandated by PURA or the state of Connecticut that have not been contemplated as of the time of this submission, or capital programs for which there is or will be distinct cost recovery (such as SHARE, if approved at some point in the future) would not be subject to the cap on investment for purposes of calculating F-Factor revenue requirements.

As described on page 102 of Exhibit ES-CLP-ELP-1, the Company's current forecast of capital expenditures presented in Figure 7 of testimony does not include the anticipated capital costs associated with an AMI deployment. If PURA were to approve an AMI deployment before or during the PBMRP term, the Company would need to increase the forecasted budget to incorporate those investments. As described on page 102 of Exhibit ES-CLP-ELP-1, the Company's current forecast of capital expenditures presented in Figure 7 of testimony does not include the anticipated capital costs associated with an AMI

deployment. If PURA were to approve an AMI deployment before or during the PBMRP term, the Company would need to increase the forecasted budget to incorporate those investments.

b. Please refer to the Company's detailed response to information request OCC-423. The Company's proposed F-Factor is an annual adjustment taking effect July 1 of each year that reflects an allowance based on the annual revenue requirement on the capital expenditures budgeted for the current calendar year (per Exhibit TSP-3), plus a downward-only reconciliation comparing the actual plant additions placed in service as of December 31 of the calendar year prior to rates taking effect. In this way, the F-Factor provides an allowance for capital investment in the rate year based on the expected capital expenditures projected in this proceeding (same as the CT-Bar), but is reconciled such that in the end the F Factor measures the actual capital investment, including plant additions, plant retirements, accumulating depreciation, cost of removal, and plant-related accumulated deferred income taxes, cumulatively from the investment allowed in base rates.

c. Yes, that is correct. Prior-year capital additions are subject to the same annual downward-only reconciliation and Forecasted Budget cap as capital additions placed in service during the applicable Rate Year.

d. The Company's proposal to implement an F Factor allowance based on the forecasted budget presented in this proceeding, subject to a downward only adjustment upon reconciliation of prior-year capital additions is consistent with the Company's characterization of the Forecasted Budget as a cap on capital recovery during the PBMRP term because the F Factor reconciliation will only reconcile downward, meaning that if, in the end, the Company's actual costs in a given year are more than it has forecasted in this proceeding, the Company would not be entitled to reconcile the F Factor to reflect the higher (i.e., above the cap) level of spending. It will only be reconciled downward, which will occur if the Company invests less than the amounts budgeted in this proceeding, and used in establishing the F Factor in a given year.

e. Rate stability is enabled by prescribed, annual adjustments, consistent with the Company's experience during the first four years following settlement of Docket No. 17-10-46. By providing the Company with incremental revenues to cover a portion of the rising costs of service, the rate increase requested in the subsequent rate case (for rates effective July 2031) would be significantly reduced both in dollar amount and in percentage change relative to then-effective rates. Moreover, the adoption of the PBMRP will enable the Company to stay-out of a rate case for the duration of the PBMRP, whereas in the absence of a properly designed PBR plan and adequate cast-off rates, the Company will not be in a position to stay out for any period of time and will require more frequent filing of base rate cases, resulting in larger and more choppy rate changes for customers than would be experienced under the PBMRP. The Company's proposed PBMRP incorporates multiple customer protections, including the effect of the cap on capital investment eligible to be supported by the F-Factor, the earnings sharing mechanism, and the consumer dividend.

Date Filed: October 27, 2026

Witness: Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP- Z factor) Refer to Exhibit CLP-ELP-1 p. 99. Define (1) State Initiated Cost Change; (2) Federally Initiated Cost Change; (3) Regulatory Cost Reassignment; and (4) Externally Imposed Accounting Rule Change as it pertains to Exogenous Events in the Company's proposal. For each category, provide specific examples of potential events the Company expects would and would not qualify for recovery as an Exogenous Event.

Response:

Below, the Company has provided illustrative examples of the types of events or changes that could qualify for exogenous factor consideration, subject to satisfaction of the applicable Z-Factor criteria:

1. State Initiated Cost Change

- A new Connecticut statutory mandate requiring a distribution-system capital investment program or activity that was not contemplated in the revenue requirement used to establish the PBMRP.

- A new or materially changed PURA or other Connecticut agency requirement imposing material incremental compliance, operational, or infrastructure requirements on electric distribution companies.

- A change in Connecticut tax law that imposes a new or materially different tax obligation specific to utilities or electric distribution operations.

2. Federally Initiated Cost Change

- A new or materially revised federal reliability or cybersecurity requirement that requires incremental distribution-system investment or operating expenditures.

- A new federal environmental requirement requiring remediation, equipment modifications, monitoring, or other incremental expenditures associated with distribution assets or operations.

- A new or materially revised federal safety or physical-security standard requiring changes to distribution facilities, equipment, systems, or operating practices.

3. Regulatory Cost Reassignment

- A change in jurisdictional cost responsibility between federal and state regulation that causes a category of costs to become, or cease to be, the responsibility of distribution customers.

- A regulatory determination that moves responsibility for a material cost into or out of distribution rates when that cost had previously been recovered through another regulatory mechanism.

4. Externally Imposed Accounting Rule Change

- A new or amended FASB accounting standard that requires a material change in the recognition or measurement of distribution-related costs.

- A mandatory regulatory-accounting change that requires costs previously capitalized to be expensed, or costs previously expensed to be capitalized.

- A mandatory accounting change that creates, eliminates, or materially changes the accounting treatment of a regulatory asset or regulatory liability.

Date Filed: October 27, 2026

Witness: Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP Z- factor) Refer to Exhibit CLP-ELP-1 p. 99. Discuss whether the proposed Z-factor would apply only to increases and decreases in distribution costs resulting from qualifying exogenous events.

Response:

Yes, the proposed Z-factor would apply only to increases and decreases in distribution costs resulting from qualifying exogenous events. The proposed Z-factor would apply equally to both qualifying cost increases as well as qualifying cost decreases. A qualifying event would be reflected through the Z-Factor only to the extent its impact is appropriately borne by distribution customers and is not otherwise captured through another PURA-approved rate mechanism. The positive or negative distribution revenue impact of qualifying events would also need to satisfy the proposed 0.5 percent materiality threshold.

Date Filed: October 27, 2026

Witness: Donald J. Scacco Jr., Digaunto Chatterjee and Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP Z- factor) Refer to Exhibit CLP-ELP-1 pp. 24-25, 99. Discuss any interaction of the proposed PBMRP and the Leadership Panel's discussion of enabling utility ownership of generation.

Response:

There is no direct interaction under the proposal currently before PURA. As the Company explained in CIEC-001[i], the Company is not advancing a specific proposal in this proceeding to authorize or implement utility ownership of generation. The Leadership Panel instead identified utility ownership as one potential resource option that should be considered as part of a broader resource-planning assessment.

Accordingly, no generation investment or related cost is included in the proposed PBMRP merely as a result of that discussion. If future legislation, regulation, or another binding governmental action were to impose a new distribution cost on the Company during the PBMRP term, any request for Z-Factor treatment would be evaluated under the Z-Factor criteria then applicable, including whether the cost is beyond the Company′s control, is not reflected in the I-Factor or another recovery mechanism, and satisfies the materiality threshold. The Leadership Panel′s policy discussion, standing alone, does not trigger the Z-Factor.

Prior Referenced Response:

[i] CIEC-001 Question:

(Executive Leadership Panel) With reference to page 21 of the Executive Leadership Panel's Direct Testimony, state whether the Company is advancing any proposal in this proceeding that would promote, allow, or otherwise enable utility ownership of generation. If the Company is advancing any such proposal in this proceeding, provide a reference to the testimony where the proposal(s) may be found.

CIEC-001 Response:

No, the Company is not advancing any specific proposal in this proceeding to promote, allow, or enable utility ownership of generation. The Company's point is that it is time to consider all alternatives to solving the energy affordability conundrum in Connecticut (and the broader New England region). This should start with development of a comprehensive independent integrated resource planning assessment that projects the state of resource adequacy under a range of scenarios – ten years out. This is the type of study completed with robust stakeholder participation

and input – including EDCs, LDCs, the legislature, and advocates for all customer segments (residential, commercial, and industrial) – that is essential to formulate an informed view of the comprehensive solution set necessary to meet the future resource adequacy needs within Connecticut. The Company is open to consideration of what would essentially be *customer-owned* generation through the utility operating model, if it would be the most cost-effective solution to meet reliability needs of Connecticut customers.

Date Filed: October 27, 2026

Witness: Donald J. Scacco Jr., Digaunto Chatterjee and Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP Z- factor) Refer to Exhibit CLP-ELP-1 pp. 22-24, 99. Discuss any interaction of the proposed PBMRP and the Comprehensive Independent Integrated Resource Plan ("CIIRP") stakeholder process described by Leadership Panel.

Response:

The CIIRP discussion does not itself create a PBMRP adjustment. The Leadership Panel proposed a comprehensive, independent stakeholder process to evaluate supply options, associated costs and implementation issues and to provide a longer-term framework for future resource decisions. No specific resource selected through such a future process is embedded in the proposed PBMRP by virtue of that discussion.

The PBMRP and the CIIRP concept therefore operate at different levels. The PBMRP is a distribution ratemaking framework for the four-year stay-out term. The CIIRP is described as a broader resource-planning process. If a future CIIRP process ultimately results in legislation, regulation, or another binding action that imposes a qualifying distribution cost change during the PBMRP, the Company would evaluate that discrete cost change under the Z-Factor criteria. The CIIRP process itself would not automatically qualify as an Exogenous Event.

Date Filed: October 27, 2026

Witness: Donald J. Scacco Jr., Digaunto Chatterjee and Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP Z- factor) Refer to Exhibit CLP-ELP-1 pp. 24-25, 99. Discuss any interaction of the proposed PBMRP and the Leadership Panel's discussion of opportunities to coordinate upgrades to the gas distribution and transmission systems to increase firm gas supply in southeast Connecticut, facilitating either the buildout of a new natural gas combined-cycle generation unit or firming up an equivalent amount of gas supply for existing generation.

Response:

There is no direct interaction under the proposal presently before PURA. The Leadership Panel identified a potential opportunity to coordinate gas distribution and transmission upgrades in southeast Connecticut to increase firm gas supply, either to facilitate new combined-cycle generation or to firm gas supply for existing generation. That discussion does not place any such investment or cost into CL&P's proposed distribution PBMRP.

To the extent a future policy or project were approved through legislation, a regulatory order, or another binding action, the ratemaking treatment would depend on the nature of the approved project and the entity and jurisdiction to which the resulting costs are assigned. A cost would not become eligible for CL&P distribution Z-Factor treatment merely because the Leadership Panel discussed the concept. Any future request would have to satisfy the Z-Factor criteria, including that the distribution cost change is beyond the Company's control, not otherwise reflected in the I-Factor or another recovery mechanism, and meets the applicable materiality threshold.

Date Filed: October 27, 2026

Witness: Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP Z- factor) Refer to Exhibit CLP-ELP-1 p. 100. For the purposes of determining the threshold significance of 0.5 percent of CL&P's total distribution revenue, please explain whether that threshold would be fixed at the Company's allowed base distribution revenue for the Rate Year, the current annual base distribution revenue inclusive of PBMRP Adjustments, or some other amount.

Response:

The 0.5 percent significance threshold would initially be calculated based on the Company's allowed total base distribution revenue requirement as established by PURA in this proceeding. Thereafter, the revenue amount used to calculate the threshold would increase by operation of the PBMRP, including the I-X and F-Factor adjustments. Accordingly, the dollar amount of the 0.5 percent significance threshold would not remain fixed throughout the PBMRP term.

Date Filed: November 03, 2026

Witness: Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBMRP Z- factor) Refer to Exhibit CLP-ELP-1 p. 100. Compare and contrast the Company's PBMRP proposal with the performance based ratemaking mechanisms allowed for Eversource's electric operations in other jurisdictions.

Response:

As described below, the Company's proposed Z-Factor is generally consistent with the exogenous-cost mechanisms applicable to Eversource's electric operations in Massachusetts and New Hampshire. Although the mechanisms differ in their eligibility criteria and materiality thresholds, each distinguishes ordinary cost variation subject to the incentives and risks of a multi-year plan from material changes outside utility management's control that may warrant separate regulatory treatment.

In this proceeding, the Company has proposed to implement an exogenous cost recovery adjustment for qualifying positive or negative cost changes that are beyond the Company's control, are not reflected in the I-Factor, and are not otherwise addressed through another PURA-approved cost recovery mechanism. Potential changes include State Initiated Cost Changes, Federally Initiated Cost Changes, Regulatory Cost Reassignments, and Externally Imposed Accounting Rule Changes. The Company proposes an aggregate materiality threshold equal to 0.5 percent of total distribution revenues. Please refer to the Company's response to BETP-004[i] for additional discussion of these categories.[1]

In Massachusetts, NSTAR Electric's exogenous mechanism provides for rate changes for qualifying industry-specific tax, accounting, regulatory, judicial, and legislative changes that are beyond the company's control and not reflected in the applicable inflation factor. It applies a $4 million individual-event threshold in the first PBR year, adjusted annually by GDP-PI, which equates to approximately 0.37 percent of distribution revenues.[2]

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[1] Exhibit CLP-ELP-1, p. 100; Company response to BETP-004.

[2] PURA Docket No. 21-05-15RE01, Eversource Energy Comments on Revised Straw Proposal (Mar. 26, 2025), pp. 34-41.

In New Hampshire, the NHPUC approved a $1.5 million applicability threshold for PSNH's exogenous-cost adjustment. PSNH explained that the threshold was intended to limit the mechanism to changes significant enough to justify a separate proceeding and to protect against events that could "upset the balance of the PBR plan during the term".[3] The NHPUC allows PSNH to seek recovery of exogenous costs driven by changes in costs driven by state or federal government entities, regulatory cost reassignments, or changes in accounting rules.[4]

The Massachusetts and New Hampshire mechanisms demonstrate that the scope and materiality of a Z-Factor may be defined differently without changing its essential purpose. The Company's proposal identifies comparable categories of externally driven cost changes, but applies a 0.5 percent threshold to the aggregate distribution-revenue impact of qualifying changes. In each case, the mechanism leaves ordinary cost variation within the PBR framework while providing a defined process for addressing material changes that arise outside the utility's control. Please refer to the Company's response to BETP-060[ii] for additional comparisons and the supporting regulatory authorities.[5]

Performance Metrics:

Regarding PBR metrics in New Hampshire, while the Company proposed additional metrics as part of DE 24-070, after investigation the Commission determined that reliability of service is a core concern for the Company's customers and adopted SAIDI and SAIFI metrics as the only metrics to be applied in the alternative regulation. The thresholds are calculated based on a five-year rolling average plus one standard deviation. If performance falls outside that threshold for any given year, a $1.5 million (revenue-requirement) penalty shall be assessed, and no offset resulting from exceeding the performance standards shall be used to reduce penalties. The Company's proposal for SAIDI and SAIFI in this proceeding is similar in that the Company's proposal calculates these metrics using the IEEE methodology, excluding Major Event Days (MEDs) and planned outages. Regarding the target threshold, while New Hampshire uses a rolling five-year average, the Company recommends setting a fixed target to apply to the full PBR term based on the most recent five years prior to the start of the PBR term. Fixing the target for the full PBR term provides clarity on the standard for performance during the PBR term. Utilizing a rolling five-year average to set targets each year during the term causes performance targets to rise or fall based on the system's most recent experience rather than focusing on a transparent measure of whether the Company has improved and maintained system reliability as compared to an established set of targets. The proposal for Connecticut also includes gradual penalties, starting at the threshold of "average plus one standard deviation" and full penalty for performance exceeding

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[3] Docket No. DE-24-070, Public Service Company of New Hampshire response to interrogatory PUC-1-004 issued September 6, 2024.

[4] Docket No. DE-24-070, Order No. 28,170, pp. 51, fn. 12.

[5] PURA Docket No. 21-05-15RE01, Eversource Energy Comments on Revised Straw Proposal (Mar. 26, 2025), pp. 34-41; Proposed Final Decision.

"average plus two standard deviations" with a penalty range of $1.75 million to $3.5 million each for Blue Sky SAIDI and Blue Sky SAIFI. The Connecticut proposal, like the PSNH metrics, do not include direct offsets resulting from exceeding performance standards for these metrics.

Regarding PBR metrics in Massachusetts, the M.D.P.U. approved a PBR plan for NSTAR Electric Company, d/b/a Eversource Energy in Order D.P.U. 22-22. In that Order, the Department approved 18 individual performance metrics. The performance metrics are for reporting purposes and do not include associated penalties or incentives. At the time of approval of the PBR plan, the M.D.P.U. acknowledged that service quality metrics, such as Blue Sky SAIDI and SAIFI, are developed and implemented under a separate regulatory framework than the PBR plan. These metrics have associated penalties under the separate service guidelines. The M.D.P.U therefore approved a broad set of PBR performance metrics that are tied to the goals of the PBR plan without making changes to the service quality guidelines. Note that the M.D.P.U. has recently reopened the Service Quality guidelines that determine the methodology and historical data to calculate targets and deadbands (D.P.U. 24-53).

Please refer to BETP-010, Attachment 1, for a full list of the Connecticut proposed PBR metrics, the New Hampshire approved PBR metrics and the Massachusetts approved PBR metrics.

Prior Referenced Response:

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[i] BETP-004 Question:

(PBMRP- Z factor) Refer to Exhibit CLP-ELP-1 p. 99. Define (1) State Initiated Cost Change; (2) Federally Initiated Cost Change; (3) Regulatory Cost Reassignment; and (4) Externally Imposed Accounting Rule Change as it pertains to Exogenous Events in the Company's proposal. For each category, provide specific examples of potential events the Company expects would and would not qualify for recovery as an Exogenous Event.

BETP-004 Response:

Below, the Company has provided illustrative examples of the types of events or changes that could qualify for exogenous factor consideration, subject to satisfaction of the applicable Z-Factor criteria:

1. **State Initiated Cost Change**

- A new Connecticut statutory mandate requiring a distribution-system capital investment program or activity that was not contemplated in the revenue requirement used to establish the PBMRP.
- A new or materially changed PURA or other Connecticut agency requirement imposing material incremental compliance, operational, or infrastructure requirements on electric distribution companies.
- A change in Connecticut tax law that imposes a new or materially different tax obligation specific to utilities or electric distribution operations.

2. **Federally Initiated Cost Change**

- A new or materially revised federal reliability or cybersecurity requirement that requires incremental distribution-system investment or operating expenditures.
- A new federal environmental requirement requiring remediation, equipment modifications, monitoring, or other incremental expenditures associated with distribution assets or operations.
- A new or materially revised federal safety or physical-security standard requiring changes to distribution facilities, equipment, systems, or operating practices.

3. **Regulatory Cost Reassignment**

- A change in jurisdictional cost responsibility between federal and state regulation that causes a category of costs to become, or cease to be, the responsibility of distribution customers.
- A regulatory determination that moves responsibility for a material cost into or out of distribution rates

4. **Externally Imposed Accounting Rule Change**

- A new or amended FASB accounting standard that requires a material change in the recognition or measurement of distribution-related costs.
- A mandatory regulatory-accounting change that requires costs previously capitalized to be expensed, or costs previously expensed to be capitalized.
- A mandatory accounting change that creates, eliminates, or materially changes the accounting treatment of a regulatory asset or regulatory liability.

[ii] BETP-060 Question:

(PBR- Z factor) Refer to Exhibit CLP-PBR-1p. 74. Provide a summary of Z Factor designs tested and implemented in other jurisdictions, including the decision where such designs were approved, the qualifying criteria for associated expenses and the associated tariffs

BETP-060 Response:

The following table summarizes the Z-Factor provisions approved in a sampling of jurisdictions that have deployed an I-X based PBR framework. Approval of these mechanisms does not necessarily constitute approval of specific cost adjustments that are generally evaluated on a case-by-case basis.

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference

New Hampshire – Public Service Company of New Hampshire	Approved a relatively narrow Z-Factor covering specific cost changes resulting from state or federal government actions, regulatory cost reassignments, and changes in accounting rules. These adjustments may be forward-looking when known and measurable.	Cost changes must fall within the Commission's defined categories and satisfy the applicable threshold. The Commission adopted its earlier definition for the exogenous-event provision.	$1.5 million revenue-requirement impact	New Hampshire Public Utilities Commission Order No. 28,170 (July 25, 2025), Docket DE 24-070, pp. 2 and 54.
Alberta –	Approved a general Z-Factor for	All five criteria must be met: (1) outside	Dollar equivalent of an after-tax 40-	AUC Decision 27388-D01-2023

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference
Electric and Gas Distribution Utilities	significant positive or negative financial impacts from exogenous events. May apply to capital or O&M. No exclusive list of qualifying events is prescribed.	management's control; (2) material impact; (3) no significant influence on the inflation factor; (4) prudently incurred costs; and (5) unforeseen event. The impact must also lack another reasonable recovery mechanism within the PBR framework.	basis-point change in ROE, calculated using the utility's equity supporting 2023 going-in rates; escalated annually by I-X	(October 4, 2023), Appendix 5, pp. 119–120.

Massachusetts – Eversource (NSTAR Electric)	Approved exogenous costs from: (1) tax-law changes uniquely affecting the industry; (2) industry-specific accounting changes; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.	Cost change must be beyond company control, arise from qualifying legal/accounting/regulatory action, uniquely affect electric distribution rather than the general economy, and not be reflected in GDP-PI. Supporting evidence is required, and eligibility is determined case by case.	$4 million per individual event in the first PBR year, adjusted annually by GDP-PI Generally noncumulative, with limited exceptions for related property-tax events	MDPU, NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 22-22, Final Order, (November 30, 2022), pp. 71–76.
Massachusetts – Fitchburg Gas and Electric Light Company (Unitil Electric)	Approved the standard MA categories of industry-specific tax, accounting, regulatory, judicial, and legislative changes.	Beyond management control; arises from qualifying changes in requirements or directives; unique to the distribution industry; material; and not reflected in the inflation index or otherwise in PBR formula.	$110,000 per event with annual GDP-PI adjustments	MDPU, Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 23-80/D.P.U. 23-81, Final Order (June 28, 2024), 51–54

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference

Massachusetts – Massachusetts Electric Company and Nantucket Electric Company (National Grid Electric)	Approved the standard Massachusetts categories. Also expressly approved potential Z-Factor recovery for certain major storm-related O&M expenses, subject to additional conditions and prudence review.	Qualifying costs must be beyond control, arise from industry-specific legal/accounting/regulatory changes, not be reflected in the applicable inflation adjustment, and meet the significance threshold. For major storms, additional storm-fund eligibility requirements apply.	$3.6 million per individual event initially, adjusted annually by GDP-PI Special storm provision: individual storm O&M expenses above $30 million, where the storm fund balance plus costs exceeding $30M, exceeds $75M.	MDPU, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 23-150, Final Order (September 30, 2024), pp. 94–96.
Ontario – Electricity Distributors	Approved a general Z-Factor mechanism for extraordinary, unforeseen events outside management's control. Examples include severe storms and other exceptional events. The framework does not restrict claims solely to legal or regulatory changes.	Three principal tests: (i) causation, (ii) materiality, and (iii) prudence. Costs must be incremental to those reflected in rates; management must show the event could not reasonably have been planned or budgeted for. Current guidance also requires the distributor's achieved ROE not to exceed its deemed ROE by more than 300 basis points.	Under the OEB's 3rd Generation IRM, the standard Z-factor materiality thresholds are C$50,000 for utilities with distribution revenue requirements up to C$10M; 0.5% of distribution revenue requirement for utilities above C$10M through C$200M; C$1M for utilities above C$200M. The threshold applies on a per-event basis.	Ontario Energy Board, Supplemental Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, Docket EB-2007-0673, (September 17, 2008), Appendix B, VII-VIII

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference
			However, utilities operating under OEB-approved Custom IR plans may be subject to different, utility-specific materiality thresholds.	
Hawaii – Hawaiian Electric Companies	Approved a broad Z-Factor mechanism for exceptional events beyond reasonable utility management control. Potential examples discussed in the proceeding include tax-law changes, natural disasters, and pandemics, but the Commission deliberately did not establish an exclusive or automatically approved list. Changes to ROE or credit ratings do not qualify.	Six criteria: (1) outside control of a prudent utility; (2) directly related to the exogenous event; (3) impact outside the original rate base; (4) prudently incurred; (5) not otherwise recovered through rates, insurance, government aid, or third parties; and (6) above materiality threshold. Each request is evaluated individually.	$4 million per event for HECO; $1 million per event for HELCO and MECO	Hawaii Public Utilities Commission, Decision and Order No. 37507 (December 22, 2020), Docket 2018-0088, pp. 57–60 and 80.

Date Filed: October 27, 2026

Witness: Donald J. Scacco Jr., Digaunto Chatterjee and Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(Utility Owned Generation) Refer to Exhibit CLP-ELP-1 p. 21-24. Please explain the Company's position on its legal authority to own the generation it is proposing in its CLP-ELP-1 testimony?

Response:

The Company's response to CIEC-001[i] explained that "the Company is not advancing any specific proposal in this proceeding to promote, allow, or enable utility ownership of generation."

Regarding BETP's request for information on the Company's position on its legal authority to own generation, the Company's legal counsel advised that General Statute Section 16-244e(a) identifies the circumstances under which an electric distribution company can own generation, stating: "An electric distribution company shall not own or operate generation assets, except as provided in this section and sections 16-43d, 16-243m, 16-243u, 16a-3b and 16a-3c, provided nothing in this section or in section 16-244w shall be interpreted to prohibit or limit the ability of an electric distribution company from building, owning or operating an energy storage system."

Prior Referenced Response:

[i] CIEC-001 Question:

(Executive Leadership Panel) With reference to page 21 of the Executive Leadership Panel's Direct Testimony, state whether the Company is advancing any proposal in this proceeding that would promote, allow, or otherwise enable utility ownership of generation. If the Company is advancing any such proposal in this proceeding, provide a reference to the testimony where the proposal(s) may be found.

CIEC-001 Response:

No, the Company is not advancing any specific proposal in this proceeding to promote, allow, or enable utility ownership of generation. The Company's point is that it is time to consider all alternatives to solving the energy affordability conundrum in Connecticut (and the broader New England region). This should start with development of a comprehensive independent integrated resource planning assessment that projects the state of resource adequacy under a range of scenarios – ten years out. This is the type of study completed with robust stakeholder participation and input – including EDCs, LDCs, the legislature, and advocates for all customer segments (residential, commercial, and industrial) – that is essential to formulate an informed view of the comprehensive solution set necessary to meet the future resource adequacy needs within Connecticut. The Company is open to consideration of what would

essentially be *customer-owned* generation through the utility operating model, if it would be the most cost-effective solution to meet reliability needs of Connecticut customers.

Date Filed: October 23, 2026

Witness: Warren R. Boutin and Andrew C. Belden
Request from: Department of Energy and Environmental Protection

Question:

(DERs) Has the Company conducted a retrospective analysis on the costs avoided by DERs against the costs incurred for integrating and supporting DERs? If so, please provide the results.

Response:

The Company has not conducted a retrospective analysis comparing costs avoided vs cost incurred. It must be noted that costs for system investments are incurred by the respective DER project and do not directly impact ratepayers.

Date Filed: October 27, 2026

Witness: Leanne M. Landry and Jeffrey D. Turano
Request from: Department of Energy and Environmental Protection

Question:

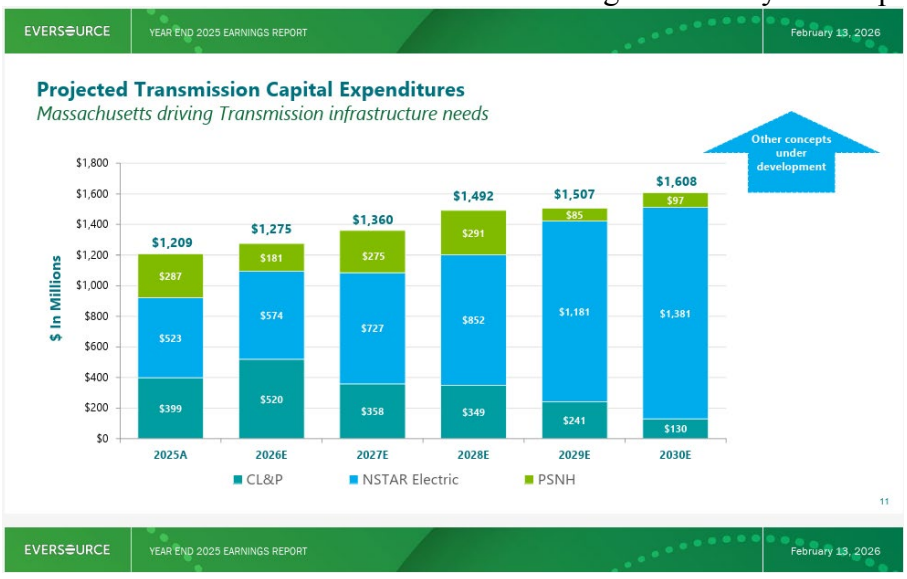
(Historic Capital Investment) Please provide by total dollars per year the amount spent on annual capital investments for each year from 2005 –2025 for: (1) distribution and (2) transmission. Are capital investments primarily constrained by capital availability or system needs?

Response:

Please refer to CIEC-008[i] for capital distribution expenditures by year from 2018 through 2025, as annually filed in compliance with Docket No. 17-10-46. The Company notes that historical capital investment data is provided beginning in 2018, as this represents the relevant historical period for purposes of the current rate case.

CL&P's transmission investment is out of scope for this distribution rate proceeding, however, for informational purposes to assist in DEEP's inquiry, please refer to the below excerpt from the Year End 2025 Earnings Report where the Company presented actual 2025 transmission capital spending and forecasted spending for the years 2026-2030. This publicly available chart summarizes the transmission capital expenditures for each Eversource Energy electric operating company.

Please refer to OCC-924[ii] which addresses budget flexibility with capital investments.



Prior Referenced Responses:

[i] CIEC-008 Question:

(Capital Additions Panel) For each of the past 10 calendar years, specify:

a. the capital expenditure budget broken down by investment in the transmission, sub-transmission, primary, and secondary systems; and
b. the amount of actual capital expenditures, broken down by investment in the transmission, sub-transmission, primary, and secondary systems.

CIEC-008 Response:

For purposes of the capital expenditure budget in this distribution rate proceeding, the Company does not track investment by the categories of "transmission, sub-transmission, primary, and secondary systems."

a. Please refer to CIEC-008, Attachment 1, for a summary of actual and forecast distribution capital expenditures for the years 2018-2025 as filed in compliance with Docket No. 17-10-46 each year.

b. Please refer to subpart a. Please also refer to Exhibit CLP-ADDITIONS-4 which summarizes the cumulative capital spending to date for each project put in service from 2017-2025 greater than $100K and Exhibit CLP-ADDITIONS 6 which includes the associated capital project documentation. Also for reference, although not capital spending, Exhibit CLP-ADDITIONS-2 and 3 provide a summary of plant additions (both distribution and transmission) by year and is reconciled to the Company's FERC Form 1.

[ii] OCC-924 Question:

(Capital Projects) Referring to Exhibit CLP-Additions-1, page 12. Please define the term "flexibility in the budget"; explain what determines whether a project has budget flexibility or not; and identify the components (i.e. project cost categories) of a project budget which are flexible and which are inflexible.

OCC-924 Response:

The term "flexibility in the budget" is a reference to the overall capital budget, not the budget for a specific project. The term refers to the ability to defer, accelerate, or reprioritize planned capital spending within a given budget period in response to changing system conditions, emerging operational needs, or unforeseen project requirements. Budget flexibility is an important component of managing a large capital portfolio and enables the Company to efficiently allocate capital to projects that provide the greatest near-term benefit to customers and system operations.

Whether a specific project has flexibility in relation to the *overall budget* depends primarily on the urgency of the underlying need, regulatory or compliance requirements, customer commitments, safety considerations, and the potential system impacts associated with delaying the work. Projects that address immediate safety concerns, mandated compliance requirements, emergent reliability issues, customer-driven obligations, or equipment failures generally have limited or no budget flexibility because delays could result in unacceptable operational, safety, or customer impacts. In contrast, projects addressing aging infrastructure that remain in serviceable condition may have greater flexibility because the assets can continue to operate safely and reliably for a period beyond the originally planned replacement date.

For aging infrastructure replacement projects, budget flexibility typically exists when asset condition, engineering assessments, operational history and system performance indicate that the asset can remain in service without creating an immediate reliability, safety, or compliance concern. In these situations, The Company may defer a planned replacement project by one or more years with limited near-term impact on customer reliability while continuing to monitor the asset through its normal maintenance and inspection programs.

Budget categories that are generally considered more flexible include planned construction expenditures associated with asset replacement programs, such as labor, materials, equipment, and contractor costs for projects that have not yet commenced construction or where construction can be paused without creating risk to the distribution system and can be rescheduled based on emergent priorities.

The ability to defer certain aging infrastructure replacement projects provides an important mechanism for managing capital expenditures within the overall portfolio. When unforeseen conditions arise, such as unexpected equipment failures, storm-related damage, deteriorated assets identified through inspections, or other emergent reliability needs, funding associated with projects that can be safely deferred may be reallocated to address those higher-priority needs. This approach allows the Company to respond promptly to emergent system conditions while continuing to maintain safe and reliable service. Deferred replacement projects remain within the long-term capital plan and are reevaluated in subsequent planning cycles to ensure that asset condition and system risk remain acceptable before replacement is further postponed.

Accordingly, budget flexibility does not reflect the elimination of planned infrastructure investments, but rather the Company's ability to optimize the timing of certain replacement projects whose deferral is not expected to have an immediate impact on system reliability, while ensuring sufficient funding is available to address unforeseen conditions that require immediate corrective action.

Date Filed: October 27, 2026

Witness: Brendan J. O'Brien, Garrett J. Murray and Steven C. Osuch
Request from: Department of Energy and Environmental Protection

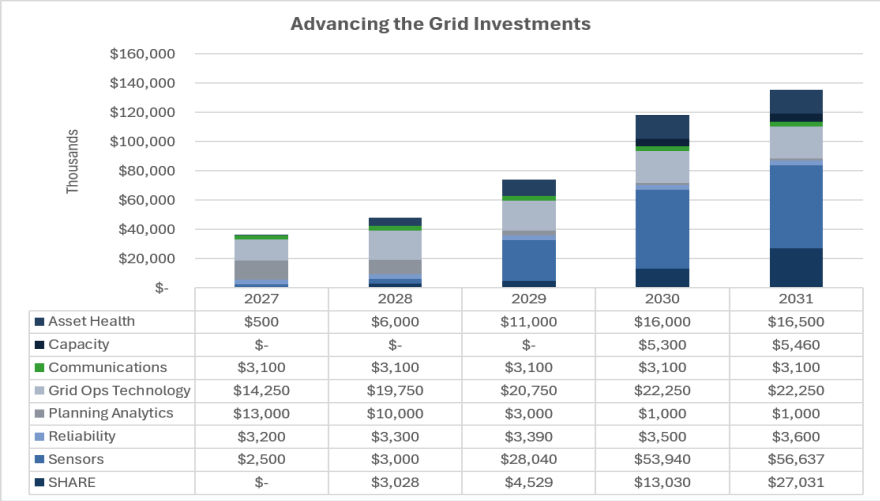
Question:

(SHARE) Refer to Exhibit CLP-TSP-3 p. 47-48. Are any of these costs related to the Shared Hosting for Advancement of Renewable Energy (SHARE) proposal? If yes, please provide a breakdown in each category listed of SHARE-related costs and non-SHARE-related costs.

Response:

Exhibit CLP-TSP-3, pages 47-48, do not pertain to the Shared Hosting for Advancement of Renewable Energy (SHARE) proposals. Rather, these pages identify grid needs that are intended to be addressed through the *Targeted System Performance* plan. Therefore, the costs presented on p. 47-48 are not categorized as SHARE-related costs.

The SHARE proposals are included within the *Advancing the Grid* planning category discussed in Exhibit CLP-TSP-3, page 131. While page 131 presents SHARE within the overall *Advancing the Grid* forecast, it does not separately provide the investment-category breakdown requested here. Therefore, to provide a response in a format comparable to the investment-category presentation shown on pages 47-48, the Company has provided the updated *Advancing the Grid* investment chart below, together with the associated category-level cost breakdown. The chart separately identifies SHARE-related investments from other *Advancing the Grid* investments.



	2027	2028	2029	2030	2031
Asset Health	$500	$6,000	$11,000	$16,000	$16,500
Capacity	$-	$-	$-	$5,300	$5,460
Communications	$3,100	$3,100	$3,100	$3,100	$3,100
Grid Ops Technology	$14,250	$19,750	$20,750	$22,250	$22,250
Planning Analytics	$13,000	$10,000	$3,000	$1,000	$1,000
Reliability	$3,200	$3,300	$3,390	$3,500	$3,600
Sensors	$2,500	$3,000	$28,040	$53,940	$56,637
SHARE	$-	$3,028	$4,529	$13,030	$27,031

Date Filed: October 27, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-3 p. 102. Please provide project details about the 39.1 MW of DER in the queue that is assumed to come online within the next three years, including but not limited to:

a. technology type;
b. size;
c. date entered the interconnection queue;
d. and any relevant ratepayer-funded incentive program the project may be participating in (e.g. Nonresidential Renewable Energy Solutions, Shared Clean Energy Facilities, Energy Storage Solutions, etc.)

Response:

Exhibit CLP-TSP-3, page 102, references the historical DER queue that existed at the time the study supporting the proposed non-wires alternative solution at the Campville 14R Bulk Substation was performed.

The Company does not maintain historical snapshots of the interconnection queue; however, BETP-015, Attachment 1 CONFIDENTIAL, provides a list of projects that were online as of 2022, as well as projects currently in the queue, which should be generally representative of the queue at that time. This information would not include projects that were subsequently withdrawn and may have been reflected in the queue when the study was originally conducted.

BETP-015, Attachment 1 CONFIDENTIAL, provides information responsive to subparts (a) through (d). With respect to subpart (d), however, the Company does not maintain a single dataset with common identifiers that can be readily queried across customer-funded incentive programs, interconnection applications and substation planning records. Accordingly, the information provided is substantially complete and reasonably representative; however, the data may contain omissions or inaccuracies resulting from limitations in the underlying source systems and the absence of direct linkages between these data sets.

Date Filed: October 27, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-3 p. 143. Please describe how the two substations from the list of eight substations identified in Docket No. 22-06-29RE01 were chosen over the others, and describe how the one additional substation was chosen over others identified in Docket No. 22-06-29RE01 for the Shared Hosting for Advancement of Renewable Energy (SHARE) proposal.

Response:

Project selection was based on limited or constrained hosting capacity within the proposed project area, the amount of distributed energy resource (DER) capacity (MW) in the interconnection queue and identified adjacent grid needs within the area. The DER capacity considered as part of this evaluation was based on the active interconnection queue at the time of project screening. Since the interconnection queue is dynamic and continually changes as projects are submitted, withdrawn, modified, or placed online, the Company focused on substations with active interconnection requests that could directly benefit from hosting-capacity improvements. While historical withdrawal activity may indicate prior interest in DER development at a particular substation, withdrawn projects no longer have active applications and therefore would not be candidates to initially benefit from the SHARE program.

Addressing DER hosting-capacity needs concurrently with identified grid needs in the area allows investment plans to be co-optimized, resulting in reduced overall cost and higher utilization. If the area system needs were addressed independently or myopically, additional future investments may be required to accommodate incremental demand growth (from load or DER), resulting in duplicative costs, including, but not limited to, mobilization, outage coordination, engineering, and construction activities. By combining these investments into a single project, the Company can address both system and DER needs more cost-effectively while ensuring that costs are appropriately allocated to beneficiaries based on capacity use.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-3 p. 145. For each of the eight proposed and potential substations to participate in the Shared Hosting for Advancement of Renewable Energy (SHARE) proposal, please provide project details about the DER in queue, including but not limited to:

a. technology type;
b. size;
c. date entered the interconnection queue;
d. and any relevant ratepayer-funded incentive program the project may be participating in (e.g. Nonresidential Renewable Energy Solutions, Shared Clean Energy Facilities, Energy Storage Solutions, etc.)

Response:

The Company provides BETP-017, Attachment 1 CONFIDENTIAL, in response to this request. The attachment provides information on active interconnection requests associated with the proposed and potential SHARE substations identified on pages 145 through 149, of Exhibit CLP-TSP-3, and provides the requested project information, including technology type, size, queue date, and participation in certain customer-funded incentive programs.

The queue information reflected in BETP-017, Attachment 1 CONFIDENTIAL, represents a current snapshot of active interconnection applications and therefore may differ from the queue values referenced on pages 145 through 149, of Exhibit CLP-TSP-3, which were based on earlier evaluations of these opportunities. Changes in queue quantities can result from a variety of factors, including new applications, completed interconnections with developer funded improvements, project modifications, incidental grid needs resulting in increased hosting capacity, and withdrawn applications. As a result, current queue levels may differ from those considered during the original screening analyses.

In particular, highly constrained substations may experience project withdrawals when substantial interconnection upgrades are required before projects can proceed. Under the current interconnection framework, the first developer to trigger such a constraint may be responsible for funding an upgrade that subsequently benefits additional interconnection customers. As a result, projects may remain in the queue for extended periods while developers evaluate alternatives or

await system improvements that may reduce assigned interconnection costs and, in some cases, projects may ultimately be withdrawn. Consequently, the active queue at a given point in time may not fully reflect the historical level of developer interest at a location. These conditions are among the challenges that the proposed SHARE framework is intended to address through a more effective allocation of upgrade costs among participating beneficiaries.

The Company also notes that certain SHARE opportunities reflected on pages 145 through 149, of Exhibit CLP-TSP-3, have been refined from the original concepts evaluated in Docket No. 22-06-29RE01. In certain cases, the Company expanded the scope from individual substations to broader group study regions in an effort to improve cost allocation and maximize benefits for stakeholders. To provide additional context regarding the current proposals, BETP-017, Attachment 1, includes summary information and supporting queue data for substations incorporated into the proposed Campville and Tracy SHARE group-study regions.

Participation in customer-funded incentive programs was compiled using information obtained from multiple Company and program-administrator data sources. Although the information provided is substantially complete and reasonably representative, the Company does not maintain a single dataset with common identifiers that can be readily queried across interconnection applications, incentive program records and planning databases. Accordingly, the attachment may reflect omissions or inaccuracies resulting from limitations in the underlying source systems, differences in data quality and the absence of direct linkages between these datasets.

Date Filed: October 27, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

How does the SHARE proposal in this filing differ from the PURA proposal in Docket No. 22-06-29RE01? How does the Company's proposal reduce costs to all ratepayers?

Response:

The SHARE program is an implementation of the technical aspects of PURA's framework as approved in Docket No. 22-06-29RE01. However, there continues to be a misalignment on implementation until such time that the cost-recovery mechanism is determined. The Company has not proposed a specific cost-recovery framework in this docket due to the procedural travel of the issue before PURA. The Company would support action by PURA to revisit implementation and cost recovery either in this case or in a separate, uncontested docket wherein all parties could participate.

1. Cost Recovery Issues

Under the SHARE framework, DER developers are responsible for the portion of project costs associated with enabling new DER interconnections, while customers contribute for those portions of a project that provide direct reliability, operational or other system benefits to customers, generally. As a result, customers would not fund the DER-specific benefits of the project but would fund the parts of the project that can produce benefits for customers as a result of implementation efficiencies, reliability improvements and the potential avoidance or deferral of future transmission and distribution investments. Increased DER penetration may contribute to reduced wholesale energy and capacity costs over time through a more diverse portfolio of generation resources within the region, reducing reliance on constrained natural gas supplies and enhancing overall energy resource diversity, providing an additional basis for customer support of this program.

To make this program work, recovery of the customer contribution would need to occur through a specialized ratemaking process that recognizes that this program is outside the distribution company's typical capital planning process. PURA would need to decide that in this proceeding, or establish another proceeding to complete its inquiry.

Under PURA's framework in the final decision issued in Docket No. 22-06-29RE01, on February 19, 2025, at page 10, PURA declined to implement "an extraordinary cost recovery mechanism

for ratepayer assigned costs resulting from the Group Study Process," stating that it will continue to consider the range of options for cost recovery and may establish a cost recovery mechanism in a subsequent proceeding or in an EDC's next rate case.

With this outcome, PURA's final decision in Docket No. 22-06-29RE01 did not support the policy objectives of the docket because, ultimately, PURA's decision did not attempt to establish a workable framework for cost recovery, preventing these kinds of projects from moving forward in Connecticut.[1] Without a determination on a workable cost-recovery framework, the Company is not in a position to enter into these kinds of arrangements because these capital costs are motivated by DER developers, not the Company's own risk assessments and prioritizations of capital additions needed on the distribution system, which is the focus of the Company's capital plan. Funding of these projects between rate cases would therefore interfere with the Company's capital plan for distribution service given that the Company's available capital is already deployed to distribution purposes for the direct benefit of customers.

On that point, in its final decision, issued on February 19, 2025, PURA stated that:

> The EDCs requested that in the absence of an annual cost recovery mechanism, the Authority allocate the full interconnection upgrade cost to Group Members. The Group Study Process as implemented in this decision does not intend such an outcome. At present, the Authority will permit the EDCs to recover their prudently incurred expenses according to the traditional ratemaking principles outlined above. ***Once again, the Authority reiterates that it may review and implement an alternative cost recovery mechanism in a subsequent proceeding or in an EDC's next rate cas***e. In the interim, the Authority orders the EDCs, pursuant to its broad statutory powers enumerated in General Statutes § 16-11, to effectuate changes in their manners of operation through the adoption of the Group Study Process as set forth in Attachment 1 of this decision. As previously explained, the Group Study Process is necessary to reduce barriers that will inhibit Connecticut from achieving its non-residential DER deployment goals.

Final Decision, February 19, 2025, at 10 (citations omitted, emphasis added).

On April 10, 2025, CL&P and The United Illuminating Company filed a petition requesting that PURA issue a series of declaratory rulings regarding the applicability of General Statutes §§ 16-

[1] The proposed final decision asserts that "[i]n the interim, the Group Study Process is operable, and the EDCs may initiate DER Group Studies for non-residential interconnection customers. Although the Authority declines to adopt a contemporaneous cost recovery mechanism at this time for the balance of interconnection ratepayer costs, the Authority will treat any costs assigned to ratepayers through the Group Study Process like other capital costs. Specifically, the EDCs may file for cost recovery of these costs in their next rate case in accordance with traditional utility ratemaking principles. At that time, the Authority will conduct a prudence review of such costs."

11, 16-19e, and 16-244z to the DER Interconnection Decision. This matter was docketed in Docket No. 25-04-05.

On June 4, 2025, PURA issued a Notice of Proceeding, Stay and Docket Closing notice, stating that the declaratory action raises arguments and issues not previously considered in Docket No. 22-06-29RE01, including but not limited to the applicability of General Statutes § 16244z(e) to the recovery of capital interconnection costs. PURA further stated that it would reopen Docket No. 22-06-29RE01, pursuant to General Statutes §§ 16-11 and 16244z and Conn. Agencies Regs. §§ 16-1-134 et seq., to address these additional considerations raised in the declaratory action and to reconsider the DER Interconnection Decision.

On August 27, 2025, PURA issued a Revised Notice of Proceeding in Docket No. 25-04-05 (Declaratory Action). In this Revised Notice, PURA stated that, on June 4, 2025, it stayed the DER Interconnection Decision and reopened Docket No. 22-06-29RE01 to address the issues raised in the Declaratory Action and to reconsider the DER Interconnection Decision. As result, PURA stated that the declaratory action proceeding was concluded without a decision and the docket closed.

On January 15, 2026, CL&P filed a motion (Motion No. 9) with PURA requesting that the reopened proceeding in Docket No. 22-06-29RE01 be closed. On January 22, 2026, The United Illuminating Company filed a motion (Motion No. 10) supporting Eversource's request that the docket be closed. On February 18, 2026, PURA granted these motions and closed the reopened docket.

In that ruling, PURA stated it would initiate a new proceeding to continue stakeholder discussions regarding non-residential interconnection upgrade cost allocation, while also asserting that the orders contained in the February 19, 2025 Decision in Docket No. 22-06-29RE01 shall remain stayed until further notice. No action has occurred in these matters since that motion ruling.

At stake is the issue that, although PURA's final decision in Docket No. 22-06-29RE01 implies that the EDCs must "effectuate changes in their manners of operation through the adoption of the Group Study Process," consistent with Attachment 1 of the decision, it is questionable (at a minimum) as to whether PURA actually has authority to compel the EDCs to expend capital resources on this program and PURA has cited only to its general oversight power for the proposition that the EDCs "must effectuate changes," consistent with Attachment 1. Accordingly, the Company has included the capital expenditures associated with the SHARE proposal in the Advancing the Grid scenario presented in Exhibit TSP-3 in this proceeding in order to obtain consideration by PURA of an appropriate ratemaking approach or in a separate, uncontested docket wherein all parties could participate.

2. Technical and Administrative Features:

Project selection is based on limited or constrained hosting capacity within the proposed project area, the amount of distributed energy resource (DER) capacity (MW) in the interconnection queue, and identified adjacent grid needs within the area. The Company also focused on substations with active interconnection requests that could directly benefit from a coordinated hosting-capacity solution. Although historical withdrawal activity may indicate prior interest in DER development at a particular substation, withdrawn projects no longer have active applications and therefore would not be candidates to benefit from a SHARE project.

In addition, the Company considered opportunities to address DER hosting-capacity needs concurrently with planned reliability and system-needs investments. By coordinating these investments, the Company can avoid duplicative costs that would otherwise be incurred if separate projects were constructed at different times, including, but not limited to, mobilization, outage coordination, engineering, construction, and other project implementation activities. This coordinated approach provides benefits to both DER developers and customers through more efficient project execution and cost allocation.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Has the Company considered the potential impact of Section 16, of Public Act 26-127, on the Shared Hosting for Advancement of Renewable Energy (SHARE) proposal? If yes, please explain the Company's analysis and understanding of these potential impacts.

Response:

Yes. The Company has considered the potential implications of Section 16, of Public Act 26-127. The Company's proposed SHARE framework contemplates continued stakeholder engagement to identify locations where a group-study approach may provide mutual benefits to interconnection customers and the electric system. Although the Company has proposed an initial set of candidate projects in this filing, successful implementation of any SHARE project depends upon participation by DER developers with active interconnection requests and their willingness to participate in the group study process and fund their allocated share of any interconnection upgrades identified through the group study process.

This type of participation could be facilitated through existing or future stakeholder working groups that could help identify locations where a group-study approach would provide the greatest value to participating developers and customers. Through this engagement, the Company would seek stakeholder input regarding project viability, developer interest, and the likelihood that available hosting-capacity allocations could be fully utilized.

To the extent Section 16, of Public Act 26-127, affects future solar siting requirements, project development considerations, or project economics, it could influence the willingness of DER developers to participate in specific SHARE opportunities, particularly in locations that may be more reliant on greenfield development. As a result, Section 16 may affect developer interest in particular locations and the viability of pursuing those opportunities through the SHARE framework.

Participation in a SHARE project would be voluntary, and DER developers would have the opportunity to evaluate applicable regulatory, siting, and economic considerations before electing to participate in a group study.

Accordingly, although Section 16 may influence the attractiveness or feasibility of certain SHARE opportunities from a developer perspective, it is not likely to create material risk to the Company

or to customers. Stakeholder engagement and consideration of developer interest are intended to help identify locations with the greatest likelihood of participation and successful utilization of the hosting-capacity benefits created through the SHARE framework. Further, because participating developers would fund their share of any interconnection upgrades identified through the group study process prior to project implementation, neither the Company nor customers would be exposed to the risk that insufficient developer participation makes a particular SHARE opportunity infeasible. To the extent additional hosting capacity is created through the use of standard equipment ratings, that capacity would remain available to accommodate future interconnection requests, including residential customers as well as commercial DER projects that decide to participate given the siting considerations contemplated under Section 16.

Date Filed: October 27, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-3 p. 103-105. Please describe the process Eversource used to estimate the cost for the battery storage projects.

Response:

For an estimate of the costs of each ESS at the most granular level available please refer to BETP-020, Attachment 1.

Budgetary quotes per site were requested and received from several ESS suppliers on a turnkey scope basis. These quotes were used in the Company's estimates. All additional scopes (materials, internal and external labor, and other investments required) for each site were developed internally and were estimated using the Company's cost estimating tools and database.

The Company provided conceptual-level estimates with an anticipated level of accuracy of -25% / +50%. This anticipated range is the Company's best effort to provide a project estimate and its range of uncertainty.

Please refer to Docket No. 22-06-05 as noted on Exhibit CLP-TSP-3 p. 101-106. All relevant materials related to these projects are included in this docket.

Date Filed: November 03, 2026

Witness: John P. DiPaola-Tromba
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-3, pp. 68–70. Please describe how the EPRI Power Transformer Expert System ("PTX") health-index results are used to select and prioritize transformer replacements. Please provide a summary table, by year for 2027–2031, showing the number of transformers proposed for replacement, the applicable health-index range, estimated replacement cost, and any other principal factor supporting replacement. Identify any material instances in which the proposed replacement order differs from the PTX ranking and explain why.

Response:

Eversource employs several methods to both actively and passively monitor the health of distribution power transformers within its service area. Active and continuous monitoring methods include out of specification alarming. Alarms may include indications for bushing monitoring (if applicable), LTC trouble, dissolved gas (if applicable), oil level alarms, and oil temperature alarms, among others.

This information along with periodic maintenance and testing reports provide data into Eversource's condition-based asset management methodology that draws on multiple sources including:

- Transformer nameplate characteristics
- Oil quality and DGA trends
- Abnormal thermal, electrical, or core indicators derived from PTX health modeling
- Maintenance and inspection records
- Power Factor Testing

Eversource utilizes a detailed asset health score generated through the Electric Power Research Institute (EPRI) PTX tool to assess power transformer asset health. OCC-596, Attachment 4 CONFIDENTIAL, is a technical guide to the EPRI Power Transformer Expert System (PTX). The PTX tool evaluates normal degradation, abnormal operating conditions, oil quality, and age to produce two critical indicators: the Long-Term Health Index (LTI) and the Short-Term Health Index (STI). The PTX health index is measured in the range of 0 to 1, with 0 meaning healthy and 1 needing immediate replacement. A value greater than 0.5 is considered poor health, such that if

repair/replacement is not performed the transformer will continue to decline leading to equipment failure.

Eversource has 27 transformers in CT, or about 8.6% of the fleet, that fall within the range considered to be in poor condition. This means that without repair or replacement, their condition is expected to continue declining, increasing the risk of equipment failure. As a result, Eversource continues to prioritize and initiate replacement projects for these transformers.

Prior to initiation of a transformer replacement project, the various subject matter experts (SMEs) will confer and review the nameplate data, maintenance records, and PTX scores of the unit. If a transformer is reviewed and a capital project is not to be initiated, the transformer is typically recommended to have further evaluation for maintenance mitigation of the found issue. This may include repairs or minor refurbishment actions that enable the power transformer to be reenergized and placed back in-service.

If the transformer is identified as requiring a capital project an initial funding is established and a project team assembled. The project team includes various SMEs and they are required to review the technical and financial feasibility of transformer replacement, transformer refurbishment, load transfer options, and usage of existing spare transformer inventory for a replacement. After the feasible options are developed, the project team will proceed with a formal review of the multiple feasible options within the procedures of the Eversource Solution Design Committee.

Using the nameplate data with age and ratings combined with the PTX scores, the power transformers will be identified to proceed with the initial capital project evaluation within the Targeted System Plan. As these evaluations are completed, the power transformers will be prioritized and projects initiated as confirmed. The project sequencing and deferral options will be evaluated within this review.

The average cost of a bulk transformer replacement project is ~$8M per unit. This cost varies with the size of the transformer and any other scope included in the replacement. Examples of other scope to be evaluated include the adjacent switches and breakers, transformer protection relaying and metering, cables and conduits from the transformer to adjacent equipment, etc. These items are evaluated and reviewed within the project approval review cycles. The Targeted System Plan includes an average of 8 bulk and distribution transformers with an investment of ~$78M per year. The exact number will vary each year as the transformers are confirmed to be replaced and the project scopes are developed and approved. A typical transformer replacement can take from 2 to 5 years to plan and execute. From the time of identification of deteriorating health, the transformer will continue to degrade over the course of the project execution time period.

Please refer to the Company's responses to OCC-596[i] and OCC-597[ii] for additional information.

Prior Referenced Responses:

[i] OCC-596 Question:

Refer to Exhibit CLP-TSP-1 at 55, "…plan to maintain a transformer fleet that does not exceed 70 years of age." Identify every law, regulation, manufacturer requirement, or mandatory engineering standard that requires a substation transformer to be retired at 40 years, 70 years, or any other specified age. If no such requirement exists, please confirm.

a. Provide all existing studies, analyses, and historical data relied upon by the Company to conclude that transformer failure risk increases rapidly as transformers approach or exceed 70 years of age. If the Company has not performed an empirical analysis using its transformer-failure experience, please justify.
b. Provide the Company data and analyses used to establish the transformer age thresholds or replacement criteria in the TSP, including the stated 40-year useful life and increased failure risk near 70 years. Include the age and cause of failure for each Company transformer that failed during the period covered by the analysis. If the criteria are not based on the Company's actual failure experience, identify the source on which they are based.

OCC-596 Response:

There are no laws, regulations, manufacturer requirements, or mandatory engineering standards that require substation transformers to be retired at a specific age. The age of a power transformer is one of the most important factors in assessing asset condition. Although actual service life varies widely depending on the manufacturer's design, quality of assembly, materials used, operating history, current operating conditions, and maintenance history, the average expected life for an individual transformer is approximately 40 years according to industry consortiums, and manufacturers. International reliability surveys (i.e., CIGRE) report major failure rates on the order of ~0.3% per transformer-year across large populations, with failure behavior influenced by aging and asset condition. Industry asset-management guidance supports risk-based decision-making that balances failure risk and cost.

Eversource employs several methods to both actively and passively monitor the health of distribution power transformers within its service area. Active and continuous monitoring methods include out of specification alarming. Alarms may include indications for bushing monitoring (if applicable), LTC trouble, dissolved gas (if applicable), oil level alarms, and oil temperature alarms, among others.

This information along with periodic maintenance and testing reports provide data into Eversource's condition-based asset management methodology that draws on multiple sources including:

- Transformer nameplate characteristics
- Oil quality and DGA trends
- Abnormal thermal, electrical, or core indicators derived from PTX health modeling
- Maintenance and inspection records
- Power Factor Testing

Eversource utilizes a detailed asset health score generated through the Electric Power Research Institute (EPRI) PTX tool to assess power transformer asset health. OCC-596, Attachment 4 CONFIDENTIAL, is a technical guide to the EPRI Power Transformer Expert System (PTX). The PTX tool evaluates normal degradation, abnormal operating conditions, oil quality, and age to produce two critical indicators: the Long-Term Health Index (LTI) and the Short-

Term Health Index (STI). The PTX health index is measured in the range of 0 to 1, with 0 meaning healthy and 1 needing immediate replacement. A value greater than 0.5 is considered poor health, such that if repair/replacement is not performed the transformer will continue to decline leading to equipment failure.
Eversource has 27 transformers in CT, or about 8.6% of the fleet, that fall within the range considered to be in poor condition. This means that without repair or replacement, their condition is expected to continue declining, increasing the risk of equipment failure. As a result, Eversource continues to prioritize and initiate replacement projects for these transformers.

Attachments included note that multiple industry sources discuss aging and failure rates of substation power transformers.

- OCC-596, Attachment 1 CONFIDENTIAL, A2 Cigre Brochure 939 AC Transformer Reliability
- OCC-596, Attachment 2 CONFIDENTIAL, 1013566 Plant Support Engineering Large Transformer End of Expected Life Considerations and the Need for Planning
- OCC-596, Attachment 3, EXEC-2022-001242 - Large Power Transformer Resilience Report 7-10-24
- OCC-596, Attachment 4 CONFIDENTIAL, 3002026877_Power Transformer Expert System (PTX) Software Application Guide_ Introduction to PTX, Overview, Technical Basis and Application Information

Based on industry experience, while transformers can operate beyond their typical design life of 40 years, the risk of failure exponentially increases after 70 years of service life, due to paper insulation degradation. OCC-596, Attachment 1 CONFIDENTIAL, a CIGRE study from 2024, shows the failure rate of transformers has a noticeable increase starting at 40 years and exponentially increases as the asset exceeds 65 years old. This study reviewed analysis of thousands of transformers including many voltage classes from around the world to build depth into the data available. OCC-596, Attachment 2 CONFIDENTIAL is an EPRI paper discussing "Large Transformer End-of-Expected Life" which notes "the useful life of a large, oil-filled transformer is between 30 and 40 years with insulation or bus supports being the most likely to fail due to age. For the insulation, thermal aging of the paper insulation is the likely cause of failure."

OCC-596, Attachment 3, is a Department of Energy report from 2024, citing that large power transformers "are typically considered to have a design lifetime on the order of 40 years. In 2014, a DOE report estimated that the average age of LPTs in the North American grid was 38–40 years, indicating that a substantial fraction of those LPTs are at or over that design lifetime. These LPTs will ultimately need to be replaced or refurbished." These industry research groups and others have provided basis within their published studies to support the concerns of failure with any transformer over 40 years in-service.

As a result, Eversource's Asset Health philosophy for transformers is to operate transformers to their maximum useful life, but plan to maintain a transformer fleet that does not exceed 70 years of age and an average age of approximately 35 years. The objective is to find the balance between affordability and preventing an aged transformer fleet that approaches the "knee of the curve" which results in failure rates that increase significantly. With a large portion of the transformer fleet being between 50 and 80 years old, as these transformers continue to approach and exceed 70 years, the rate of failure will increase rapidly. Due to the complexity and time duration of procuring and replacing transformers, a significant increase in failures would result in the inability to maintain reliability by reactively replacing an increased volume of transformer failures.

The six most recent failures of transformers in CT were all attributed to internal failures of the transformer. The ages of the failed transformers were 32, 50, 52, 52, 56, and 83 years old at the time of the failure.

[ii] OCC-597 Question:

Refer to Exhibit CLP-TSP-1 at 55. For each proposed proactive replacement, identify whether the Company evaluated continued operation through enhanced inspection, testing, monitoring, maintenance, refurbishment, loading limits, load transfer, or use of a spare transformer. Provide each existing analysis and state whether it found that replacement could be deferred by one, three, or five years. If no deferral or life-extension or alternate analysis was performed, please confirm the reason.

OCC-597 Response:

Eversource employs several methods to both actively and passively monitor the health of all power transformers within its service area. Active and continuous monitoring methods include out-of-specification alarming. Remote alarming (if applicable) is conducted through the Eversource SCADA system with alarms existing for bushing monitoring, LTC trouble, dissolved gas, oil level alarms, and oil temperature alarms, among others. Per industry best practices, local alarming is performed through panel indication lamps with corresponding nameplate alarm descriptions and annunciation technologies such as bulb annunciators and Human Machine Interfaces (HMI's).

The preventive maintenance procedures for power transformers are documented within the Eversource Maintenance Program (EMP) 5.58 Station Transformers and Oil-Filled Shunt Reactors. The inspection and maintenance tasks are catalogued into three (3) categories which include a list of asset conditions for real-time condition monitoring, time-based regular inspections, and condition-based maintenance activities. These are described in more detail below:

Condition Monitoring: Various parameters related to power transformer health are actively monitored as applicable. The monitoring is performed both locally and remotely with local monitoring performed by individual equipment alarms and station annunciators. Remote monitoring is performed via Supervisory Control and Data Acquisition (SCADA) to enable real-time asset parameter output and SCADA equipment alarms. Such parameters include temperature, oil level, pressure, and load tap changer (LTC) status.

Time-Directed Maintenance and Inspections: Eversource has established multiple routine maintenance activities required to be performed for all power transformers within specific time intervals. These activities include monthly visual inspections, annual oil sampling including dissolved gas analysis (DGA), thermographic readings, LTC maintenance, and major maintenance activities. Major maintenance activities include power factor testing, bushing testing, excitation testing, confirmation of proper operation and integrity of pressure relief devices and ensuring all alarms operate properly.

Condition-Based Maintenance: These activities are on an as-needed basis when identified upon visual inspection, when performing time-directed maintenance activities, and when output from condition monitoring devices indicate outside normal operating values. Such activities include, but are not limited to, acoustic measurements, core grounding tests, leak repairs, and chassis repair.

Substation Technical Engineering leverages data collected by the CASCADE, PTX Analysis, and substation equipment databases to perform asset condition assessments of power transformers. The reports are based on the following six (6) parameters with recommendations for replacement by the Substation Technical Engineering team being based upon whether two (2) of the following

(6) parameters are considered high risk:

- Oil Analysis Results
    - DGA
    - Fluid Quality Analysis
    - Furan Analysis on Main Tanks
- Age

- Loading
- Maintenance History
- Historical Test Data
- Physical Inspection Findings

The above practices are applicable to all power transformers. Asset age and condition will prompt enhanced inspection, testing, monitoring, and maintenance as noted in the EMP toward the goal of maximizing the usable life of a transformer.

Historically the Company has effectively maximized the life of Transformers by extensive maintenance and monitoring practices, evidenced by the age demographics of the fleet which far exceed the typical design life of 40 years. While this practice continues, the risk profile of an aging fleet compounded by longer lead times and more challenging outage constraints has resulted in a need to initiate planned replacements, beyond the historical average of 1-2 transformer replacements per year, to minimize overall impact of a failed transformer and maximize efficiency. A typical transformer replacement can take from 2 to 5 years to plan and execute. From the time of identification of deteriorating health, the transformer will continue to degrade over the course of the project execution time period. While spares are an effective mitigation plan for emergent failures, it is not a "one-size fits all" long-term mitigation plan to address the fleet risk because depending on when the failure or urgent replacements occur, it may happen at a high-risk period of the year which cannot be controlled exposing the system and customers to a much higher risk. Allowing transformers to run to failure also poses a serious safety risk to both the public and utility workers. Additionally a failed transformer could cause damage to adjacent healthy equipment compounding the negative impact.

Prior to initiation of a transformer replacement project, the various subject matter experts (SMEs) will confer and review the nameplate data, maintenance records, and PTX scores of the unit. If a transformer is reviewed and a capital project is not to be initiated, the transformer is typically recommended to have further evaluation for maintenance mitigation of the found issue. This may include repairs or minor refurbishment actions that enable the power transformer to be reenergized and placed back in-service.

If the transformer is identified as requiring a capital project an initial funding is established and a project team assembled. The project team includes various SMEs and they are required to review the technical and financial feasibility of transformer replacement, transformer refurbishment, load transfer options, and usage of existing spare transformer inventory for a replacement. After the feasible options are developed, the project team will proceed with a formal review of the multiple feasible options within the procedures of the Eversource Solution Design Committee.

Using the nameplate data with age and ratings combined with the PTX scores, the power transformers noted in Exhibit CLP-TSP-1 at 55 have been identified to proceed with the initial capital project evaluation within the Targeted System Plan. As these evaluations are completed, the power transformers will be prioritized and projects initiated as confirmed. The project sequencing and deferral options will be evaluated within this review.

The two active and ongoing projects for transformer replacements included within the Targeted System Plan followed the processes noted above, were prioritized within the project portfolio, and are planned to be placed in-service in 2028.

Date Filed: November 05, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Please provide a reconciliation, by year for 2027–2031 and by major program category, of the approximately $3.985 billion Targeted System Performance Plan to the Company's capital-additions forecast. Please identify the following in this reconciliation:

a. forecasted expenditure;
b. expected in-service amount;
c. primary investment driver;
d. and proposed recovery mechanism for each category.

Please identify which amounts are authorized, under design, conceptual, or contingent on a future event. Separately identify IT, Facilities, and Basic Business capital expenditures excluded from the engineering plan.

Response:

Plant additions and capital expenditures are two different perspectives on the same underlying investment. Capital expenditures are generally organized and managed around specific business objectives, programs, projects, or asset installation efforts, such as substation expansions, feeder rebuilds, pole replacement programs, or other distribution system investments. Capital expenditures are incurred over the course of project execution and may span multiple months or years depending on project scope, complexity, and construction schedules.

Plant additions, by contrast, are recognized when utility assets are placed in service and meet the applicable accounting criteria for recording as utility plant. Accordingly, a plant addition is generally recorded at a specific point in time, whereas the associated capital expenditures may have been incurred over an extended period.

The Company develops its forecast of plant additions using its capital investment plans, project schedules, anticipated in-service dates when possible, and historical experience. However, actual in-service dates may differ from forecasted in-service dates (where available) due to changes in project scope, construction sequencing, permitting, material availability, operational considerations, weather, or other factors. Consequently, the timing of annual plant additions may differ from the timing of annual capital expenditures. While such timing differences may occur in

any given year, over a multi-year period it is reasonable to expect that plant additions, together with associated cost of removal, will generally track with capital expenditures.

Please refer to the Company's responses to OCC-423[i], OCC-857[ii], OCC-858[iii], and EOE-371[iv] for further discussion on the reconciliation of capital expenditures and capital additions and the rate recovery mechanisms for these investments.

Prior Referenced Responses:

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[i] OCC-423 Question:

Exhibit CLP-ELP-1 Please explain in detail why the Company believes its proposed treatment of capital expenditures under the PBMRP, including the use of forecasted capital expenditures and the F-Factor, is preferable to including capital expenditures within the Revenue Cap Formula framework as proposed in the Docket No. 21-05-15RE01 Proposed Final Decision. In your response,

a. Please explain why the Company believes O&M expenses are appropriately subject to an externally indexed revenue cap, while capital expenditures require separate recovery through an F-Factor based on a fixed annual capital investment forecast.
b. Please explain how the Company's proposed treatment of capital expenditures is expected to produce customer cost savings or otherwise improve customer affordability relative to including capital expenditures within a revenue cap formula.
c. Please explain how the proposed F-Factor mitigates or avoids any incentive to favor capital expenditures over O&M solutions, including in circumstances where either a capital or O&M solution could be used to address the same system need.

OCC-423 Response:

The Company appreciates OCC's thoughtful and analytical questions on the Company's proposed performance based multi-year rate plan ("PBMRP") and looks forward to further discussion on the development of a workable PBR framework for the Company's customers.

To cover the issues raised in the question, the Company's response is organized as follows:

1. Review of relevant aspects of the Company's PBMRP.

2. Considerations on the design of capital-driven revenue support.

3. Specific responses to parts (a), (b) and (c), above.

1. Review of the Relevant Aspects of the Company's PBMRP

Ultimately, the Company's goal in this proceeding is to establish a sustainable, cohesive ratemaking framework that advances 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 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.

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.

For any multi-year rate plan to be successful, it needs to be grounded in the reality of the utility's costs, while also incorporating features that innately push the utility to be more efficient. That is not to say every dollar of the utility's costs will be (or should be) recovered. Rather, the allowed revenues need to be sufficient to afford the utility a reasonable opportunity to cover its cost of service to customers, including a reasonable rate of return on equity ("ROE") where the utility is operating prudently and efficiently, as required by state law. A framework in which the utility has no reasonable opportunity to earn its ROE, regardless of how hard it strives for efficiency, simply becomes self-defeating because the utility will exercise its statutory rights to a distribution rate proceeding, thereby muting the most powerful efficiency feature of a multi-year rate plan, which is the stay-out term.

A framework that underestimates the actual cost to run the system and/or affords the utility no reasonable chance to earn its allowed ROE, year after year, also results in under-investment and a system that not only lacks innovation, but falls further and further behind at a significant – albeit potentially unseen – cost to customers. As a result, a lasting, productive framework is one that is soundly informed by – not detached from – the drivers of the utility's real cost of service, including its cost of capital.

In this context, the two most critical features of the Company's PBMRP are as follows:

- A going-in revenue requirement that reasonably reflects the Company's actual operating expenses and cost of investment in the Rate Year, so that through effective management and prudent decision making, the Company can achieve the true efficiency gains that will be needed to stretch the approved revenue requirement over the stay-out term. Without a reasonable opportunity to maintain financial integrity over a stay-out period, as measured by the authorized ROE, the utility cannot focus on innovation and efficiency gains – and will instead file for the next rate case to make up ground. To accomplish this goal, the overall paradigm must "hang" together, making the base revenue requirement a pivotal element. The many components of a PBR plan, including going-in rates, as well as the subsequent rate adjustments, must work in concert with performance objectives and the capital investment requirements expected of the Company – for the benefit of customers, i.e., the entire framework must work to the benefit of customers, not only in relation to the price they will pay, but also in relation to supporting the level of service that they need and expect.
- Revenue support for incremental capital investment to support long-term system goals. The Company operates in a capital-intensive industry and has a substantial need to acquire cash on a systematic basis to operate its business. As annual capital investments regularly exceed net cash from operations (i.e. cash receipts from customers net of operating cash outflows), the Company must look to other capital sources to fund those investments. Those sources are the debt and equity investors supplying the cash to capital markets. This means the Company must compete with all other entities participating in those markets to attract capital. It is simply not possible for the Company to go to those markets and demand cash for free, or at below-market rates relative to the investor's risk when other entities participating in the same capital markets offer compensation for the use of funds over time.

The Company provided extensive analysis and discussion on the cost of capital throughout Docket No. 21-05-15RE01, including specifically as it relates to CT-Bar. PURA's treatment with respect to going-in revenue requirements as well as any ongoing capital-driven revenue support mechanism, such as CT-Bar, is paramount to whether the Company, with effective management and sound decision-making, can responsibly cede its right to file for a rate amendment, whereas that is otherwise the only tool the utility has to align its revenues and costs and have a reasonable chance at earning its authorized ROE, which, over time, is necessary in order to attract the capital necessary to meet the standards of service expected of the Company's customers.

The lack of a valid revenue requirement component within the CT-Bar that would allow recovery of the cost of capital associated with incremental capital investment over the term of the PBMRP is a non-starter from a policy perspective, creating an obstacle that would block a utility from giving up its right to file for rate modifications over the multi-year period in question. This is particularly accurate in the present environment in which significant increases in the level of necessary system investments are expected (and planned). Simply put, the CT-Bar, as previously envisioned in PURA's draft PBR decision, fully prevented the Company from having any practical chance at staying out of a rate case, and therefore, would never work to create a reasonable PBR framework.

The Company's proposed PBMRP in this docket is designed to track the design of the CT-Bar as closely as possible, given that this was PURA's developing framework. However, the Company's PBMRP addresses the two primary faults in PURA's RE01 framework that would prevent the implementation of a workable PBR framework, which are (1) the deviations from ratemaking fundamentals that grossly understate the "going in" revenue requirement; and (2) modification of the CT-Bar to reflect the revenue requirement applicable to capital investment, which would include recovery of the cost of capital and the cost of removal over the course of the PBMRP term. The Company's F-Factor also corrects for the mechanical error of deducting depreciation expense from new plant additions, rather than from rate base.

In particular, the Company's proposed F-Factor is designed to recover no more than the revenue necessary to support a discrete amount of ongoing system investment, recognizing that the cost of capital is a lawful and factual cost of service that must be incorporated into the revenue requirement calculation for the Company, as it is for any utility.

2. Considerations on the Design of Capital-Driven Revenue Support

CT-Bar, as defined in PURA's Proposed Final Decision, issued in Docket No. 21-05-15RE01, on July 14, 2025 (the "RE01-PFD"), had several sensible qualities that the Company supported. However, those "sensible" qualities were overcome by certain critically flawed concepts that would need to be modified or eliminated in order for the Company to consider committing to a stay-out. The positive and negative CT-Bar qualities are outlined briefly here and discussed in greater detail below, including with respect to similarities or differences to the Company's proposed F-Factor.

Summary of constructive features of PURA's RE01-PFD:

1) Acknowledgement that current revenue support for *ongoing* investment is essential;

2) No category of capital investment was summarily or preemptively excluded from CT-Bar;

3) CT-Bar takes effect with Rate Year 1; and

4) CT-Bar aligns capital revenue support with the capital investments of the DSP.

Summary of unworkable features of PURA's RE01-PFD:

1) Exclusion of the recognition in the CT-Bar of the cost of capital between rate cases.

2) Exclusion of cost of removal in the CT-Bar.

3) Application of depreciation expense as a reduction to plant additions rather than rate base.

Constructive features of PURA's RE01-PFD:

1) **Positive #1: Acknowledgement that current revenue support for *ongoing* investment is essential to the integrity of the PBR framework.**

First, that the CT-Bar even existed in PURA's RE01-PFD is genuine acknowledgement that some form of revenue support for rate year investment is essential to support a PBR framework. As discussed at length in that docket, the Company anticipates significant system investment over the next five years to advance the state's clean energy and reliability goals. Revenue support for *ongoing* system investment is crucial for any multi-year rate plan, whether in the form of the Company's proposed PBMRP, step increases, or any other ratemaking framework. CT-Bar's inclusion in RE01-PFD is a clear indication that incremental revenue support for ongoing system investments is a necessity.

2) **Positive #2: No category of capital investment was summarily or preemptively excluded from CT-Bar.**

Second, the RE01-PFD did not exclude particular categories of capital investment. For example, capital investments in facilities, fleet and information technology are viewed as permissible categories for revenue support in the CT-Bar framework. This is consistent with the Company's proposed F-Factor in this proceeding.

3) **Positive #3: CT-Bar takes effect as of Month 1 of Rate Year 1.**

The Company provided extensive discussion and analysis throughout Docket No. 21-05-15RE01 technical sessions and data responses regarding the "going-in" revenue requirement and the detrimental financial consequences of limiting capital investments to a period of time removed from the rate year. Ignoring for a moment the CT-Bar's deficiencies, having the mechanism take effect Month 1 of Rate Year 1 minimizes or eliminates those detrimental timing consequences, particularly in light of the fact that PURA has in recent years moved away from its prior practice of implementing future-test years in base rate proceedings, instead favoring a strict historical test year practice as it relates to plant additions.

Revenue decoupling is a factor to consider here because the revenue decoupling mechanism ("RDM") subsumes all sales growth to the extent that it is occurring, funneling incremental sales revenues back to customers. RDM is supported by valid policy reasons; however, the fact is that there are capital costs associated with adding new customers. Historically, when consistent and steady levels in the range of ~3$ per year of annual growth in sales and revenues was available to a utility to help offset the cost of incremental capital additions between rate cases, the pressing need for incremental revenue support was mitigated. Without the ability to capture that sales growth, and combined with the absence of an ongoing revenue support mechanism such as an F Factor taking effect on Month 1 of Rate Year 1, the Company would not be in a position to commit to a stay-out of any duration. This is because the Company would never be in a position to cover its cost of service (inclusive of its authorized cost of capital) because its rates would be set on a historical level of plant additions, despite the fact that its capital expenditures are higher than historical levels of depreciation, and because revenue decoupling ensures that even if load growth exists (and even if such load growth is enabled by the Company's increased level of capital expenditures) the Company is unable to retain additional revenues contributed by new customers, or new load.

4) **<u>Positive #4:</u> CT-Bar was designed to align capital revenue support with the DSP.**

Ignoring its deficiencies, the CT-Bar's connection to the Distribution System Plan ("DSP") constituted an essential link between ongoing system investments necessary to meet the objectives of the DSP with the revenues necessary to support those investments. Throughout Docket No. 21-05-15RE01, the Company advocated strongly for clearly defined linkages across all three tracks (RE01, RE02 and RE03), including proposing what would be the final technical session touching upon revenue requirements, in which those linkages were discussed. The Company's F-Factor is similarly aligned with the capital investment forecast provided in this proceeding for the DSP. The Company's capital investment forecast serves as the basis for a cap on the level of investment for the F-Factor.

<u>Unworkable Features of PURA's RE01-PFD:</u>

1) **<u>Negative #1</u>: No recovery of cost of capital in the revenue requirement for capital investment between rate cases.**

The single-most problematic feature of the CT-Bar was its intentional exclusion of the cost of capital associated with completing capital plant additions to the benefit of customers. Costs of capital are real costs of providing electric distribution service to customers in the State of Connecticut (or anywhere) and are recognized in statute. Although the cost of capital may be a more challenging cost to conceptualize, it is nonetheless as real as vegetation management, insurance, customer service, or any other cost of service. Cash is not free, a fact arising from its scarcity. Fundamentally, capital markets are where people, banks, corporations and other institutions provide their surplus of cash -- which is limited, to those entities that have cash needs -- which are generally unlimited. Consequently, and unsurprisingly, those entities providing the cash for some period of time expect to be compensated for providing it, thus establishing real cost to acquire capital.

The Company, operating in the capital-intensive industry of regulated utilities, is one of those entities that needs to acquire cash to operate its business. As annual capital investments regularly exceed its net cash from operations (i.e. cash from customers), the Company must look to other sources to fund those investments. Those sources are the debt and equity investors supplying the cash to capital markets. This means the Company must compete with ALL other entities participating in those markets. It is simply not possible for the Company to go to those markets and demand cash for free (or for below-market rates, relative to market expectations of risk and reward) when other entities participating in those capital markets offer adequate compensation for the use of funds over time. Therefore, there is a real and tangible cost to acquiring that capital. Please refer to the Company's pre-filed cost of capital testimony for in-depth discussion of the cost of capital.

The Company provided extensive analysis and discussion on the cost of capital throughout Docket No. 21-05-15RE01, including specifically as it relates to CT-Bar. PURA's treatment with respect to going-in revenue requirements as well as any ongoing capital revenue support mechanism, such as CT-Bar, is paramount to whether the Company, with effective management and sound decision-making, has the opportunity, but not a guarantee, to cover its cost of service to customers, and to earn its allowed return. The absence of the cost of capital from the CT-Bar, particularly in the present environment where significant increases in the level of necessary system investments are expected, prevents the Company from having any practical opportunity to commit to a stay-out to avoid the next rate case.

As discussed in the Company's response to OCC-435, based on the Company's current assessment of system investment needs in the near future, the revenue requirement associated exclusively with the cost of capital pertaining to future capital additions (excluding GET and Uncollectible) would amount to an incremental $15.6 million for Rate Year 1; an incremental $32.8 million for Rate Year 2; an incremental $36.4 million for Rate Year 3; and an incremental $39.5 million for Rate Year 4, or $124.1 million in total.

This means that -- even if 100% of those future plant additions were only partially supported with CT-Bar revenues (i.e. revenue covering depreciation expense and property taxes only); and even if the Company's future cost of service otherwise was 100% supported with rates; and even with perfect operational decision making -- the Company would still need to find $124.1 million of annual savings by Rate Year 4 in order to offset the loss of revenue associated with carrying costs on incremental investment over the term of the PBMRP, which would be necessary to commit to a stay-out term.

For perspective, the total O&M expense included in the Company's cost of service filed in this proceeding is $547.5 million. Thus, to earn its authorized ROE, all else equal, the Company would have to generate cost savings amounting to $124.1 million, or nearly 23%, of its Rate Year O&M level by Year 4, to offset the impact of the accumulating carrying costs on the incremental capital additions completed on the system after base rates are set in this case. This is nearly 34% of operating expense, excluding vegetation management and storm restoration costs, which is a very substantial proportion of the cost of service.

For example, the amount of $124M is nearly two-thirds of the Company's labor and labor-related operating expense, or 60% more than the entire vegetation management program. It simply is not possible for the Company to cut this level of O&M expense without grossly debilitating the Company's ability to provide service to customers. In fact, it is not plausible to expect that the Company could generate even 10% in annual incremental O&M savings in the face of 2-3% annual inflation and, as a result, the Company could not agree to a stay out under circumstances where there is no recovery of the cost of capital on incremental investment over the PBMRP term.

Moreover, even if the Company were somehow able to find such remarkable cost savings, the going-in revenue requirement of the subsequent multi-year rate plan would capture those cost savings. Assuming continuation of the same PBR framework and required system investment, the Company would again be in the position of having to find *an additional* 34% of O&M savings (i.e. more than 60% cumulatively from Rate Year 1) in order to sustain itself over the next PBR term. Clearly, a framework that does not provide revenue supporting the full cost of incremental investment over a four-year period, as well as the next four-year period, is not a plausible or lasting framework. Thus, exclusion of the cost of capital from a capital support mechanism in an environment in which significant increases in capital investments are expected all but ensures the Company has no realistic opportunity to survive the PBR term without a critical need for a rate case to realign costs and rates. Consequently, the overall framework as outlined in the REO1-PFD had no practical chance of sustaining the Company financially for the four-year term, nor would the Company have been able to even agree to a stay-out.

To address this indelible flaw, the Company's proposed PBMRP in this docket is designed to produce the revenue necessary to support ongoing system investment through the F-Factor, which calculates a revenue requirement inclusive of the costs of capital unlike the CT-Bar, while preserving the customer benefits and inherent incentives of a PBR plan.

2) **<u>Negative #2</u>: Exclusion of cost of removal from the revenue requirement on capital investment between rate cases.**

CT-Bar excluded the cost of removal, which is a real cost for all utilities. As a simple example, to install a new utility pole where there is an existing one that needs replacement, the Company must first remove the existing utility pole. That cost is separate and distinct from the cost of the utility pole itself; yet, similarly recovered (as an estimate) over the life a utility pole. The Company's capital investment forecast in the present docket includes approximately $136 million of cost of removal for January 1, 2026 through June 30, 2028, and approximately $60-70 million per year thereafter. A total of $60-70 million in annual investment equates to pre-tax cost of capital of $6-7 million annual *incremental* revenue requirement (e.g. $6 million year 1, $12 million year 2, $18 million year 3, etc.). The CT-Bar

revenue requirement intentionally excluded this component of the capital investment revenue requirement. The Company's proposed F-Factor calculation properly restores this component to the rate base computation.

3) **Negative #3: Depreciation expense is used as a reduction to plant additions rather than to total rate base, consistent with fundamental ratemaking principles.**

CT-Bar's calculation treats depreciation expense as a net against plant additions. Although the Company appreciated that PURA found it important to capture ongoing depreciation expense in the annual revenue requirement calculations, the overall execution of the computation was not correct. The Company's F-Factor corrects for this methodological error. Please refer to the example below outlining the mathematical problem:

($ Millions)

1	Correct treatment of depreciation's accumulation in rate base					
2		Rate Base			RevReq	
3		Year 1	Year 2		Year 1	Year 2
4	Plant Additions	$1,000	$1,000			
5	Cumulative Gross Plant	$1,000	$2,000	x 3.6% Depreciation	$36.0	$72.0
6	Accumulated Depreciation	-$300	-$600			
7	Cumulative Rate Base	$700	$1,400	x 9.8% Cost of Capital	$68.6	$137.2
8				Total Revenue Requirement	$104.6	$209.2
9						
10	CT Bar					
11		Rate Base			RevReq	
12		Year 1	Year 2		Year 1	Year 2
13	Plant Additions	$1,000	$1,000			
14	Depreciation Expense	-$300	-$300			
15	Net Plant Additions	$700	$700			
16	Cumulative Depreciable Base	$700	$1,400	x 3.6% Depreciation	$25.2	$50.4
17	Cumulative Rate Base	$700	$1,400	x 9.8% Cost of Capital	$68.6	$137.2
18				Total Revenue Requirement	$93.8	$187.6
18				Error	-$10.8	-$21.6

The table above is a simplified example of CT-Bar's improper incorporation of ongoing depreciation in a revenue-requirement calculation. Effectively, the CT-Bar reduces plant additions by depreciation expense, which improperly reduces the total amount of plant to be depreciated, thereby reducing the incremental depreciation expense to be supported by the rate mechanism. The correct approach is to handle the plant additions separately from accumulated depreciation (see lines 4 and 6 in the table above). Note that both methods result in the same return on rate base, demonstrating that both calculations reflect the reduction to return on rate base resulting from ongoing/accumulating depreciation. The error is limited to the resulting new depreciation expense reflected in the revenue requirement, which is understated in the above example by $10.8 million in Year 1 and $21.6 million in Year 2 under the CT-Bar as compared to the Company's proposal in this proceeding, which mirrors in concept to how the Company records depreciation expense on gross plant additions (not on net plant additions, as in the CT-Bar).

⇒ **Characteristics of the Company's Proposed F-Factor (same as CT-Bar, except for three features).**

The Company is proposing a capital support mechanism (the "F" factor in the formula) that tracks as close as possible to PURA's CT-Bar, except that it addresses the three major impairments described above, which would prevent the

Company from being able to agree to a stay-out. These three items are the exclusion of the cost of capital in the revenue-requirement computation for incremental plant additions, the cost of removal and the mechanical deduction of depreciation expense from plant additions instead of rate base. In the Company's F-Factor, these first two items are included in the formula and the third mechanical process is addressed.

Beyond that, the F Factor would operate from a fixed annual capital investment level for each year of the PBMRP, with reconciliation through PURA's annual RAM proceedings. The fixed annual investment level would be set at the Company's capital forecast, as approved in this proceeding. As described previously, the Company has presented different investment trajectories in the Company's 5-Year TSP and is proposing to establish the capital support mechanism of the PBR adjustment consistent with the annual capital funding requirements presented in Figure 7 of Exhibit CLP-ELP-1.

Consistent with the structure of the CT-Bar in the RE01-PFD, the F-Factor would commence on July 1, 2027, coincident with new base rates, collecting an allowance developed from the Company's capital forecast presented in Exhibit CLP-TSP-3. In this proceeding, the Company has proposed base rates that include capital additions through the Rate Year. This means that the F-Factor implemented on July 1, 2027 (commensurate with new rates in this proceeding) would be set to zero at that time, since base rates would be set to collect the revenue requirement on capital placed into service in the rate year.

However, if PURA declines to incorporate rate-year capital additions into base rates in this proceeding, the F-Factor taking effect on July 1, 2027, would reflect the revenue requirement for the period July 1, 2027 through June 30, 2028 on capital additions placed in service (or estimated to be placed in service) from the point in time where PURA cuts off capital for inclusion in base rates and through June 30, 2028.1 In the next year, as part of the Company's annual RAM compliance filing, actual plant additions placed in service during the applicable plan year would be reconciled against the F-Factor allowance put into rates on July 1, 2027. In that reconciliation, the Company would present its project document for a prudence review and, based on PURA's findings in that prudence review, the cost of actual plant additions for calendar year 2027, less whatever PURA has already included in rates for capital additions in 2027, would be actually incorporated into rate base at that point. Following PURA's determination that the Company's actual plant additions are prudent, used and useful, the Company's rate base would be adjusted and associated revenue requirement allowed for recovery that would be limited to the lesser of:

1. The total revenue requirement for the forecasted capital approved in this proceeding for the first implementation of the F Factor; or
2. The total revenue requirement for the actual plant in service.

If the cost of the Company's actual capital additions were to exceed the forecasted amount approved in this proceeding, the Company would not be permitted to obtain recovery of the incremental investment during the initial four-year PBMRP Term. Instead, any such investment would remain subject to review and consideration in a subsequent base rate proceeding or successor PBMRP Term.

This Company's proposed capital funding mechanism sets a defined cap on capital recovery during the plan term, providing customers with greater rate certainty and placing the risk of excess capital spending requirements on the Company. The annual reconciliation further protects customers by blocking recovery of investments that are delayed, deferred, canceled, or not placed in service, since those costs would not be reflected in the F factor, which is based on plant in service. For these reasons, the proposal aligns cost recovery with prudent investment, promotes accurate capital forecasting, and incentivizes efficient execution of the capital program, all while preventing customer over-collection.

III. Specific Responses to Parts (a), (b) and (c), above.

(a) Why are O&M expenses appropriately subject to an externally indexed revenue cap, while capital expenditures require separate recovery through an F-Factor based on a fixed annual capital investment forecast?

The capital investments the Company must make to provide electric service to customers in the State of Connecticut is a "local" concept. Those investments are driven by the circumstances and objectives of the State of Connecticut and the history and current status of the distribution grid in Connecticut. Those circumstances and objectives, which require long-term system planning and appropriate capital resources, are not encapsulated by a single index. O&M, though it is similarly influenced by local circumstances, does not change at the same rate as capital investment. For example, the Company's annual capital investment is expected to increase nearly 40% from $549 million in 2025 to $758 million by 2028, or more than 11% annually, on average. In contrast, over the same timeframe O&M (excluding storm funding and vegetation management) is projected to increase approximately 3-4% annually. The Company's proposed PBMRP aligns revenues with drivers of cost while maintaining the incentive to control costs.

In addition, under PBR theory, where capital inputs are contemplated in the indexed formula, then the X factor is negative, implying that the annual adjustment is inflation *plus* an additional factor. The testimony of London Economics in Exhibit CLP-PBR-1 reviews the results of their total factor productivity study producing this result. In this case, the Company elected to adhere as closely as possible to PURA's (draft) CT-Bar in order to remain synched with PURA's policy direction.

(b) How will the Company's proposed treatment of capital expenditures be expected to produce customer cost savings or otherwise improve customer affordability relative to including capital expenditures within a revenue cap formula.

There are three main opportunities for customer benefit in the PBR framework, which are: (1) the opportunity to leverage the stay-out term to drive operational efficiency and cost savings; (2) the opportunity to spread rate changes out over time to smooth impacts for customers and employ the concept of gradualism rather than promoting the cost and inefficiency of a traditional rate-case cycle; and (2) the opportunity to develop a systematic investment plan that promotes operational efficiency and cost-saving procurement strategies, while taking advantage of the smoothing impacts of the PBR framework to mitigate cost impacts.

The Company has submitted substantial testimony and documentation in this proceeding to provide insight into the level of capital investment that is needed on the system to provide adequate service to customers and to support the economic vitality of the State of Connecticut. Customers benefit directly when investment can be undertaken on a planned, systematic and consistent basis over time because (1) it is consistently more expensive to complete infrastructure projects tomorrow rather than today due to price inflation and other factors; and (2) the Company's process inputs (i.e., primarily labor and materials) cost less when procured on a planned and systematic basis rather than on an emergent basis.

Although difficult to define in terms of the overall cost trends, there are significant benefits for customers in an operating approach that is consistent, systematic, planned and carefully managed, which is an outcome that the Company is hoping to promote with its proposals in this proceeding. Bottomline – the Company is looking to establish a ratemaking framework that will promote efficiency of operations for the benefit of customers and the F-Factor is the optimal mechanism for that purpose.

Assuming that OCC's referenced alternative for a capital-cost mechanism "within a revenue cap formula," means that the PBMRP would rely exclusively on an "I-X" revenue cap formula, with or without X defined with a negative factor, the Company's experience is that it is not adequate to support necessary capital investment, while raising issues for

stakeholders. With the negative X factor, there is no direct link between the actual cost of capital plant additions and the revenue collection through customer rates, leaving it to be insufficient to support necessary capital investments and unsatisfactory for stakeholders that want transparency between the costs collected in rates and the rates that customers pay. As a result, achieving the efficiency needed to support a cost-effective capital plan is illusory in this model.

(c) How does the proposed F-Factor mitigate or avoid any incentive to favor capital expenditures over O&M solutions, including in circumstances where either a capital or O&M solution could be used to address the same system need?

In the Company's experience, implementation of the X factor mechanism (with a negative X factor) to cover capital investment was thought to be a mechanism that would promote efficient solutions between capital and O&M because the revenue allowance was not predicated on actual plant additions; rather, was simply formulaic. In 2017, the Massachusetts Department of Public Utilities ("MDPU") approved a negative X factor within a revenue cap for NSTAR Electric Company d/b/a Eversource Energy – and it remained operative for the five-year term of the plan. However, the fact is that – during an extended stay-out period, there is no incentive to incur any greater level of expense than is absolutely necessary to run the business. Therefore, there is no greater impetus than would exist in any event to make the optimal choice between expense and capitalization, where such a choice exists. And again, with the negative X factor, the MDPU felt it had no line of sight as to whether funds allowed to NSTAR Electric through the annual PBR allowance were, indeed, being leveraged for system investment.

Therefore, in 2022, the MDPU instituted the K-Bar providing an allowance for system infrastructure projects, coupled with reporting requirements on investment levels. The MDPU maintained the I-X formula to cover the O&M portion of the approved revenue requirement, which is what the Company is proposing in this case.

In reality, there are very few instances when system needs can be easily transitioned between a capital-work solution or a work solution that can be expense. The prudence review is the primary and most effective tool that regulators possess for evaluating these situations.

[ii] OCC-857 Question:

(Capital Support Mechanism) On p. 101 of Exhibit CLP-ELP-1, the Company states that, "As part of the Company's annual RAM compliance filing, actual plant additions placed in service during the applicable plan year will be reconciled against the approved forecast." In the Company's response to EOE-156, Witness Horton states that prudence reviews would be included in the annual reconciliation process.

a. Provide a detailed plan for how the Company envisions the annual reconciliation process would proceed and how long the process would take both as a whole, and for each step. Please identify what filings would be made, whether and how discovery would be allowed, and what types of determinations would be required by the Authority.
b. Where in the reconciliation process will the distinction and differences be identified between realized annual plant addition costs and the associated rate base, and the return, taxes, and deprecation on rate base that are included in the going-in revenues?
c. Will the annual PBR reconciliations be assessments of the whole Company's rate base with calculations of commensurate return, tax and depreciation, or will it be an incremental adjustment based on annual plant additions? Please explain.
d. Provide one or more examples, as appropriate, showing how the annual capital recovery process, including reconciliation, would function, including detailed calculations in the form to be used in the annual adjustment filings.
e. Provide a list of all types of costs that will be included in the capital recovery reconciliations.

OCC-857 Response:

a. The Company has given this process a lot of thought based on discussions throughout the PBR dockets. Based on input from those sessions, the Company's proposal is to align the Performance Based Multi-Year Rate Plan (PBMRP) with the Rate Year, and as much as possible, aligns with the existing annual RAM ratemaking process. As such, the Company proposes that PBMRP adjustments occur on each July 1, starting with July 1, 2027, and annually thereafter. For each year that the PBMRP mechanism is in effect, the Company would submit an Annual PBR Plan Compliance Filing to PURA in the annual RAM proceeding. The annual compliance filing would include, among other things:

(1) the calculation of the annual revenue-cap adjustment;
(2) the new proposed rate using the PBR formula;
(3) an earnings-sharing computation;
(4) cost documentation for the Company's capital investments;
(5) the calculation and reconciliation of the annual capital-cap adjustment;
(6) documentation of metric performance and resulting penalties or incentives; and
(7) bill impacts of the new rate by rate class.
(8) as applicable, any request for exogenous cost recovery.

With respect to the capital-support mechanism or "F" factor in the formula, the Company proposes a mechanism based on a fixed annual capital investment level for each year of the PBMRP, with reconciliation through PURA's annual RAM proceedings. The fixed annual investment level would initially be set at the Company's capital forecast, as approved in this proceeding, and would be subject to downward-only reconciliation1 in the event that either i) the Company's actual plant in service is lower than projected and utilized in establishing the initial F-Factor for that Rate Year or ii) PURA ultimately denies as imprudent a level of investment that was initially included in the F Factor allowance. In this way, customers are assured that rates ultimately reflect the costs of system investments that are actually in service, and have been found prudently incurred by PURA.

As described in its Exhibit CLP-ELP-1 testimony, the Company has presented different investment trajectories in the Company's 5-Year targeted system performance (TSP) and is proposing to establish the capital support mechanism of the PBR adjustment consistent with the annual capital funding requirements presented in Figure 7 of the Exhibit CLP-ELP-1 testimony. As part of the Company's annual RAM compliance filing, actual plant additions placed in service during the applicable plan year would be reconciled against the approved forecast that would have been utilized in the prior PBMRP filing to establish the F-Factor initially.

Following PURA's determination that the Company's actual plant additions are prudent, used and useful, the Company's allowed rate base and associated revenue requirement for that year will be limited to the lesser of (1) the total revenue requirement for the forecasted capital approved in this proceeding; or (2) the total revenue requirement for the actual plant in service. As described previously, if the Company's actual capital additions exceeds the forecasted amount approved in this proceeding, the Company would not be permitted to seek recovery of the incremental investment during the initial four-year PBMRP Term. Any such investment would instead remain subject to review and consideration in a subsequent base rate proceeding or successor PBMRP Term.

The Company's proposed capital funding mechanism sets a defined cap on capital recovery during the plan term, providing customers with greater rate certainty and placing the risk (and cost) of increased capital spending on the Company during the course of the PBMRP. The annual reconciliation further protects customers by blocking recovery of investments that are delayed, deferred, canceled, or not placed in service, since those costs would not be reflected in the "F" factor upon reconciliation, which is based on plant in service. For these reasons, the

proposal aligns cost recovery with prudent investment and incentivizes efficient execution of the capital program, all while minimizing customer over-collection.

Based on the above framework, an exhibit that demonstrates a revenue requirement consisting of: (1) a reconciliation of actual plant additions placed in service during the previous calendar year against the approved forecast (also referred to as the F-factor allowance) for that calendar year, and (2) the F-factor allowance for the new Rate Year beginning July 1st, would be filed on or about March 1st of each year consistent with the timing of all other RAM component reconciliations. Concurrent with that timing, all plant additions documentation for the previous calendar year included in the above reconciliation will also be filed on or about March 1st as part of the same filing.

Further, under the Company's proposed timeline, the revenue requirement resulting from the reconciliation of the prior year's F-factor allowance and the new Rate Year's F-factor allowance will go into effect on July 1, following the March 1st filing. As part of the RAM process, PURA performed prudence reviews of capital documentation filed for the ESI, including discovery, between March 1st and September 1st, the date on which additional RAM rate changes were made. Even though PBMRP rates would go into effect on July 1st, the Company proposes that this timeline continues to be used for capital prudence reviews under the PBMRP.

To the extent PURA's prudence review warrants any adjustment to the revenue requirement that went into effect on July 1, the Company will calculate the excess revenue collected from customers over the period of July 1 through August 31 and include this amount, plus carrying costs for those 2 months, in the RDM's allowed revenue target for the July 1 through June 30th Rate Year.

b. Please refer to subpart (d) of this question.

c. Please refer to subpart (d) of this question.

d. Please refer to the example shown in EOE-156, Attachment 1, pages 4 through 12, showing how the annual capital recovery process, including reconciliation, would function, including detailed calculations in the form to be used in the annual adjustment filings. Please note that pages 4, through 12, show an illustrative example for all four Rate Years contemplated for the duration of the PBMRP; however, the annual filing would only be for a single year of the PBMRP. As part of this example, please refer to the differences between realized annual plant addition costs and the associated rate base, and the return, taxes, and depreciation on rate base that are included in the going-in revenues found in EOE-156, Attachment 1, worksheet "PBR-7 Going-In Capital RR", Lines 13-16. Additionally, the detailed calculations shown in EOE-156, Attachment 1, pages 4 through 12, demonstrate that the annual PBR reconciliations will be an assessment of the Company's total accumulated depreciation included in base distribution rates (i.e., customers will be receiving credit for the increase in the Company's accumulated depreciation for all capital included in base distribution rates), as opposed to the Company's entire rate base (the Company considers its entire rate base to include other rate base items such as deferred assets and liabilities, etc.).

e. The revenue requirement for capital recovery will include appropriate recovery of net plant in service, accumulated deferred income taxes ("ADIT") and accumulated depreciation for the cumulative additional plant additions and will include a pre-tax return on investment (i.e. return on rate base including income taxes), return of investment (i.e. depreciation), property taxes, gross earnings tax and uncollectible expense.

[iii] OCC-858 Question:

Refer to Exhibit CLP-ELP-1, figure 7. Please explain whether the amounts shown in Figure 7 are capital expenditures versus plant additions. Please explain any differences in the nature, or timing of the amounts shown in Figure 7 and the amounts of plant addition that would be used in comparing [i.e., determining "lessor of"] annual plant addition costs in the annual reconciliation filings.

a. Please identify, in disaggregated table form, all of the component costs included in each category of the amounts shown in Figure 7.

OCC-858 Response:

Plant additions and capital expenditures represent two different ways of viewing the same underlying investment. Capital expenditures are generally organized and managed around specific business objectives, programs, projects, or asset installation efforts, such as substation expansions, feeder rebuilds, pole replacement programs, or other distribution system investments. Capital expenditures are incurred over the course of project execution and may span multiple months or years depending on project scope, complexity, and construction schedules.

Plant additions, by contrast, are recognized when utility assets are placed in service and meet the applicable accounting criteria for recording as utility plant. Accordingly, a plant addition is generally recorded at a specific point in time, whereas the associated capital expenditures may have been incurred over an extended period.

The Company develops its forecast of plant additions using its capital investment plans, project schedules, anticipated in-service dates when possible, and historical experience. However, actual in-service dates may differ from forecasted in-service dates (where available) due to changes in project scope, construction sequencing, permitting, material availability, operational considerations, weather, or other factors. Consequently, the timing of annual plant additions may differ from the timing of annual capital expenditures.

While such timing differences may occur in any given year, over a multi-year period it is reasonable to expect that plant additions, together with associated cost of removal, will generally track with capital expenditures.

The amounts shown in Figure 7 are forecasted capital expenditures associated with the Company's planned investment programs. As stated in its response to OCC-423i and other interrogatories, the Company's annual F-Factor reconciliation would consider specifically the plant additions actually placed in-service through the calendar year-end prior to a given annual filing.

For subpart (a) of this request, please refer to OCC-858, Attachment 1.

[iv] EOE-371 Question:

(F-FACTOR; TARGETED SYSTEM PERFORMANCE PLAN) Refer to Response to EOE-156, Att.1-Att.2. The Company's F-Factor Excel spreadsheet (PBR-4 F-Factor tab) details monthly Plant Additions, Retirements, and Cost of Removal and cites "Exhibit CLP-ELP-1, Figure 7, annual figure divided by 12 less COR" and "Per Company Financial Forecast". Additionally, the PBR-6 Capital Expense Forecast tab details similar annual information by category. Please provide the underlying information used to derive the cited Figure 7 and the Financial Forecast. As part of the response, provide a detailed listing of all planned capital additions, the anticipated in-service date, the total amount per addition, the category, and any additional details available to assist in understanding the nature and timing of the planned capital additions. This request also attempts to understand the level of information available for parties to assess if the planned capital additions within the TSP are adequately substantiated for both necessity and anticipated cost.

EOE-371 Response:

Please refer to the Company's response to interrogatory OCC-858i, which describes the capital expenditure forecast as well as plant placed into service. Additionally, OCC-858, Attachment 1, provides additional details of the investments comprising the amounts shown in Figure 7.

For additional discussion of the Company's TSP and proposed F-Factor, please refer to the Company's responses to interrogatories OCC-857ii, EOE-372iii, and EOE-374iv. As explained therein, the capital forecast presented in this proceeding serves as the foundation of the Company's proposed F-Factor framework.

As the Company explained in response to EOE-374:

"[…] the Company is proposing a hard cap on core capital investment eligible for the F-Factor based on the capital forecast presented in this proceeding. By doing so, the Company can provide upfront, during this proceeding, indicative revenue increases necessary to support those investments while committing to cap resulting revenue increases during the PBMRP even if actual capital investment exceeds the forecast. Additionally, the downward-only reconciliation of the Company's proposed F-Factor protects customers from theoretically-excessive investment, including even investments unforeseen today."

The information underlying Figure 7 of Exhibit CLP-ELP-1 and the F-Factor calculations reflects the Company's current assessment of the investments necessary to maintain and improve the system over the PBMRP term, based on the operating conditions, planning assumptions, and system objectives known today. Accordingly, the forecast serves two critical purposes in this proceeding: it establishes the maximum level of capital investment eligible for recovery through the F-Factor (excluding AMI and other legislatively mandated capital programs not contemplated today) and provides the basis for the illustrative revenues necessary to support those investments.

Consistent with the structure of the proposed PBMRP, the Company's proposal does not require a determination, in this proceeding, of the prudence of individual capital projects that may ultimately be undertaken during the plan term. Rather, the focus at this stage is appropriately placed on the Company's TSP, including the system needs, operating conditions, and policy objectives currently facing the Company, and the revenues necessary to support the investments intended to address those needs and achieve the objectives of the PBMRP, based on the information available today.

The proposed annual reconciliation and prudence review is the mechanism through which the necessity, reasonableness, execution, and support for specific investments can be evaluated based on actual facts rather than forecasts. By the time of prudence review, stakeholders will have access to the completed investment, project-specific documentation, actual costs, rationale, and the circumstances that existed when the investment decision was made. Accordingly, the annual review process places parties in a substantially better position to evaluate prudence than would be possible in this proceeding, which necessarily relies on forward-looking forecasts and planning assumptions and precedes the investments themselves. This distinction is important because it aligns the review with the information available at each stage of the process. This proceeding necessarily relies on forecasts and planning assumptions to establish prospective investment levels and associated revenue requirements, while the annual reconciliation permits review of actual investment decisions based on a complete factual record available at that time.

This structure also provides important customer protections. Customer rates ultimately reflect only prudent investments, not merely the projected investments and associated revenue requirements presented today. Recovery remains subject to review through the annual reconciliation process, and only investments found prudent are eligible for recovery through the F-Factor. At the same time, the Company's proposed hard cap ensures that recoverable capital investment cannot exceed the forecasted level of investment presented and approved in this proceeding. Taken together, these features protect customers from recovery of imprudent investments, recovery of capital investment

above the level forecast and approved in this proceeding, and the rate shock commonly experienced with traditional ratemaking.

Date Filed: October 23, 2026

Witness: David L. Gladey and Jennifer A. Schilling
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-1, pp. 33–36 and 67–71; Exhibit CLP-TSP-2, pp. 45–48; and Exhibit CLP-TSP-3, pp. 91–92 and 136–139. Please describe the Company's current and planned use of artificial intelligence and machine learning technologies in Connecticut. In the Company's response, please include the following:

a. whether the use case is currently in practice, being piloted, or has been proposed for future development;
b. the expected benefit to customers;
c. the anticipated implementation timeline;
d. and any significant data, cybersecurity, workforce, or other foreseeable barriers to implementation.

Response:

Eversource, consistent with other utilities and industries, can use AI in two main ways; first, use AI as a productivity enhancing and coding and analytics support tool and second, build or buy software tools and applications that have AI embedded. Regarding the first type of AI use, as a workforce assistance tool, at the time of this response, the Company has enabled business users to use Microsoft Copilot, as an overall personal productivity enhancing tool. Microsoft Copilot is not connected to any Company databases or software systems. Moreover, AI can run under the hood of various applications and software with or without the user's knowledge or ability to choose or not to use it. As a simple example, a search in a web browser still results in an AI-generated response. Many cloud based (SaaS) systems are continuing to introduce AI capabilities on a day to day to basis and the expectation is that AI capabilities will be embedded in progressively more commercial tools.

Regarding AI-embedded tools, there is a limited number of internally developed tools that run AI, currently utilized at CL&P. For example, the Control Room Call Analytics Dashboard is used by System Operations Management to efficiently flag training opportunities by analyzing calls between operators and field crews.

The Company continues to research and review novel and emerging technologies. We expect future AI products and outputs to increase capabilities while keeping humans in control of decisions and outcomes to promote safe and reliable service. Cyber and physical security of our

field staff and customers will always be a red line in evaluating the operationalization of any technology, including AI. As is the case for many other companies and industries, the future of AI applications at Eversource is highly volatile and unpredictable at this time.

Date Filed: October 23, 2026

Witness: David L. Gladey and Jennifer A. Schilling
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-1, pp. 33–36 and 67–71; Exhibit CLP-TSP-2, pp. 45–48; and Exhibit CLP-TSP-3, pp. 91–92 and 136–139. Did the Company use any artificial intelligence or machine learning in development of the proposed TSP? If not, explain whether and when the Company expects to incorporate those capabilities into its planning process.

Response:

The Company did not directly use AI tools, like ChatGPT or Claude or similar models, in its development of the TSP. The Company notes that AI can run under the hood of various applications and software with or without the user's knowledge or ability to choose or not to use it. As a simple example, a search in a web browser still results in an AI-generated response. The Company continues to actively evaluate AI capabilities and use cases.

Date Filed: October 27, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-3. For each proposed substation or distribution-capacity project identified, please briefly identify the principal alternatives considered, including:

a. load transfers;
b. equipment uprating;
c. storage
d. demand response;
e. flexible interconnection;
f. or other non-wires alternatives.
g. Please provide the estimated cost, implementation timeline, and principal reason each alternative was rejected or not selected. If no alternatives analysis was performed, explain why.

Response:

The substation capacity projects identified in the workbooks are in various stages of the project-approval process. None of the projects have reached a stage that would have received a detailed NWA analysis to date. As these projects proceed through the solution selection and engineering stages, NWA and other alternatives will be vetted. The results will be submitted during the annual grid needs filing as part of the NWS docket. For additional project details, please refer to the Company's response to OCC-599[i], identifying current project status, estimated budget, and any alternatives identified at this time.

The line capacity projects identified currently exceed the planning criteria based on metered data and NWS solutions were analyzed as alternatives to traditional line projects. Demand response and flexible interconnections were not evaluated as alternatives due to the lack of both a DERMS system and AMI. The Company submitted all capital projects to the process monitor as part of Docket No. 25-08-08 and the ongoing Docket No. 26-08-08.

Please refer to BETP-025, Attachment 1, identifying alternatives reviewed for distribution line projects. Please note that the PAF reflects only alternatives that were evaluated and determined to be feasible. As an example, load transfer options that were found to be infeasible were not included among the listed alternatives.

Prior Referenced Response:

[i] OCC-599 Question:

Refer to Exhibit CLP-TSP-3 at 22–24.

a. Provide the data underlying the headroom and constrained-area presentations on pages 22–24. For each substation identified as constrained, provide its normal and emergency rating, five-year historical load and peak load data, available headroom, forecast first year of violation, and proposed project cost.
b. For each constrained substation identified, provide the existing analysis of temporary and permanent load transfers. Identify the receiving substation or feeder, available transfer capacity, MW that could be transferred, required enabling work, estimated cost, and reason any transfer was rejected. Please confirm if no transfer analysis was performed.
c. Provide a summary of each actual substation capacity violation and stranded-load event experienced from 2016 through the present. Identify the substation, date, maximum loading, applicable rating, duration, contingency, customers at risk, customers interrupted, and whether load transfer prevented or reduced an outage.

OCC-599 Response:

a. The graphic depicted in CLP-TSP-3, at 22, is derived from headroom data for substations with actual values, time series data, and ratings shown on our public maps using the Eversource CT Grid Connection Navigator. Loads are based on our most recent summer peak year, 2025. Please refer to OCC-599, Attachment 1 CONFIDENTIAL, for project forecast violation year and the 5-year historical peak load data for each respective project. The table contains the LCC rating of each substation which is the planning criteria identified within the DSPG, please refer CLF-SC-023, Attachment 1. The following substations have projects initiated and have obtained at a minimum a conceptual level estimate:

Substation	**Estimated Project Cost**
West Brookfield 14H	$16,900,000
Beacon Falls 11N	$12,632,000
Franklin Drive 1B	$17,986,000
Southington 4C	$9,772,600
Berlin 6A_13.8kV	$23,199,000
Westside 7A	$18,399,000
Hopewell 22R	$17,518,000

All other substations within the attachment have not had a comprehensive evaluation to identify possible solutions and the costs associated with those solutions. The table below depicts a high-level tabletop analysis for possible projected cost of a substation solution. These costs will be refined as these projects progress through the funding process and receive full engineering analysis for solutions and conceptual level estimates.

Substations	**High Level Estimate**	**Project Status**
Waterside 22M	$600,000	Investigating Project Need
Flax Hill 24A	$500,000	Investigating Project Need
Rocky Hill 12Y	Less than $250,000	Investigating Project Need – Anticipating Permanent Load Transfer from West Brookfield 14H with settings changes only
Triangle 11A	$4,800,000	Initial Funding Approved
Middle River 28M	$500,000	Investigating Project Need
Rockville 14W	$10,000,000	Initial Funding Approved
Campville 14R	$52,300,000	Partial Funding
Baldwin 13F	$20,250,000	Initial Funding Submitted
Tracy 14M	$9,900,000	Initial Funding Approved
Frybrook 13B	$20,000,000	Initial Funding Approved
Brooklyn 30Y	Less than $250,000	Investigating Project Need – Anticipating Permanent Load Transfer from Tracy 14M or Frybrook 13B with settings changes only

b. Prior to initiating a funding project, permanent load transfers are, in many cases, a preferred solution if the conditions at the constrained substation and the adjacent area support this as these are typically substantially lower cost than substation investments and have a much more rapid deployment timeline. Historically these load transfers were not explicitly tracked, and the Company does not possess historical data as it pertains to deferrals by means of permanent load transfer. As of 2024 the Company identified this opportunity to begin having a detailed record of load transfers, partly in response to increasingly constrained regional capacity. The Company is now prepared to track these transfers in the Step Load Tracker as a load transfer on the receiving substation and a negative load transfer to the originally constrained station. This tracker will not only allow the forecasted load transfer to be visible but will also allow for historical reporting of deferred major capital upgrades through completed load transfers.

   The newly identified projects are in early stages of development and have not yet completed the solution selection process yet. Therefore, these projects would not yet have any tracked load transfers or analyses completed to date. Following initial funding of these projects, all available solutions including permanent load transfers, non-wires solutions, and traditional solutions are identified and evaluated for suitability and for viability. No potential solutions have been rejected at this time from these newly identified projects. Temporary transfers are reserved for substations anticipating overload during a current planned peak event, planned or unplanned outages, or other transient system events. Temporary solutions place the system in an abnormal condition which can impact operations, protections and controls, and automations within the system and are not used as a long-term solution except where necessary to address real-time operational needs that do not have a permanent solution placed into service.

c. All substation forecasted violations are mitigated by using pre-contingent load transfers to adjacent substations with remaining capacity. In accordance with planning criteria in the Distribution System Planning Guide (CLF-SC-023, Attachment 1), the Company plans and designs its system to avoid overload of major substation assets such as transformers during an N-1 event. During real-time operation, these overload scenarios are avoided

through the use of monitoring technology and planned mitigation measures. However, the Company's substation planning group recreates a normalized substation load to aid in the process of forecasting for future years.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Integrated Distribution System Plan) Refer to Exhibit CLP-TSP-1, Exhibit CLP-TSP-1, p. 69. Please explain further the Company's statement that "the Companies have provided their version of the IDSP with reduced scope". Provide specifics on where the Company's TSP differs in scope from the Authority's Version in Docket No. 21-05-15RE03.

Response:

Based on the question, the Company clarifies the comment referenced in Exhibit CLP-TSP-1, at page 69. The "reduced scope" version of the IDSP referenced here refers to the Company's response to a proposal issued by PURA on what the IDSP should include, not the TSP submitted in this filing.

The Company submitted a proposal for a reduced scope version of the IDSP[1] for PURA to consider in Docket No. 21-05-15RE03, in order to focus on customer affordability and delivering benefits at a lower cost, with the key focus on:

1. A more contained and streamlined stakeholder process;

2. A reduced number of scenarios for the Company to consider and develop as part of planning; and

3. A more limited granularity of system modeling and forecasting.

PURA, in its most recent proposed final decision, made certain modifications to the requirements (with the exception of the stakeholder process) that align with the Company's request ask for two incremental FTEs as part of this filing (please refer to the Company's response to OCC-835[i]).

[1] The Company filed this proposal as written exceptions in response to the draft decision for Docket 21-05-15RE03 on Aug 28th 2025. Please see the link to the document: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/6ec4c362aab351ff85258cf400701215/$FILE/Docket%20No.%2021-05-15RE03%20-%20UI%20CLP%20Joint%20Written%20Exceptions%208.28.25.pdf

In the Company's response to OCC-566[ii], the Company has provided a more detailed mapping of its TSP content (which is not the IDSP) to the IDSP proposed outline.

Prior Referenced Responses:

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[i] OCC-835 Question:

Payroll. Refer to the response to OCC-333 which states that of the 41 new positions requested, 21 vegetation management, 5 power quality positions and 2 distribution planning and forecasting positions are contingent on PURA's approval in this case. If they are contingent on PURA's approval, explain how these positions are necessary.

OCC-835 Response:

For the 21 vegetation management positions, all but one (1) of these are already included in the current vegetation management operations and are necessary for the accomplishment of the vegetation programs. The Company is proposing a shift from contract to internal resources in this case.

As noted in the Company's response to OCC-333:

"The Vegetation Management positions allow the Company the opportunity to improve the system's reliability and improve cost-efficiency by transitioning more work in-house to restructure vegetation management performance for the benefit of our customers. While the twenty-one (21) Vegetation Management positions appear to be incremental, in reality there is only 1 incremental resource. Of the twenty-one (21), eight (8) of the FTEs are the result of 16 employees who currently split their time 50%/50% between O&M and capital work shifting to solely working on the proposed combined O&M program, if approved, results in the equivalent of 8 incremental employees working on the O&M program; twelve (12) resources would be converted from contracted resources to internal resources of which the Company's proposed vegetation management expenses in Exhibit CLP-REVREQ-2, Work Paper C-3.31 reflect the reduction in outside contractor services; and one (1) resource would be truly incremental."

The five (5) power quality positions allow the Company to better serve our customers with dedicated resources that can troubleshoot, analyze, and identify power quality problems. Power Quality is typically a deviation from sinusoidal voltage or frequency and encompasses a wide variety effects, ranging from voltage sags and swells, surges, transients, low power factor, harmonics and other phenomena that disrupt service or damage customer and utility equipment. The causes of these issues can be failing equipment, lightning, equipment operation or installation as well as customer loads and DER, identifying the causes and mitigation requires specialized skills, field data and analytics. Currently within the Company there is no dedicated group responsible for resolving customer power quality issues This group will take ownership of these complaints and problems and troubleshoot customer power quality issues by taking actual field measurements at both the Company and customer premises. With field measurement and further engineering analysis, the power quality group will be able to identify the source of power quality concerns which could be at the utility side or at the customer side. Based on the group's assessment the Company will be able to improve response to customer power quality concerns and improve customer service.

The two (2) distribution planning and forecasting positions are designated resources for forecasting and modeling in distribution planning to comply with PURA's requirements outlined in the IDSP for advanced forecasting, 8760 forecasting, and larger number of scenarios, as well as to manage the stakeholder input, verification, and data sharing efforts associated with the IDSP docket. As stated by the Company in 21-05-15 RE03, compliance with an IDSP as

outlined by the Authority will require significant additional efforts. Not adding these incremental positions would severely hamper the Company's ability to:

- Meaningfully engage with the stakeholder process, review recommendations, data sets, and provide adequate responses and justifications to stakeholders
- Limit the ability to develop more than the currently staffed and resourced for single scenario peak load forecast
- Jeopardize the 8760 model delivery at circuit levels as envisioned by the Authority and Stakeholders

Supporting this effort would in turn provide the Company with these abilities, which would provide the Authority and stakeholders with more granular data as envisioned by the IDSP to better understand investment decisions.

[ii] OCC-566 Question:

In Exhibit CLP-TSP-1, Page 13, Eversource notes the following: "*The purpose of our joint testimony is to present CL&P's 5-Year Targeted System Performance Plan (the "TSP Plan" or the "Plan"), covering the planning horizon for operations and investment on the Company's distribution system over the timeframe of January 1, 2027, through December 31, 2031. A summary narrative of CL&P's State of the System report providing a foundational perspective on the 5-Year Plan is provided herewith as Exhibit CLP-TSP-2. In addition, a detailed presentation of the 5-Year TSP framework is presented as Exhibit CLP-TSP-3*."

The proposed decision issued on July 17, 2026, in docket 21-05-15RE03 lists the following content items for inclusion in an IDSP document:

a. Executive Summary - identifies key points from each section of the document;
b. Planning Policy – discusses relevant state and local goals and policies that inform grid planning;
c. Current State of the System – provides an overview of existing grid conditions including but not limited to capacity, reliability, and DER integration issues;
d. IDSP Methodology – explains the planning methods used to produce the IDSP;
e. Stakeholder Engagement and Social Equity – specifies how stakeholders participate in the IDSP process, as well as social and environmental equity considerations;
f. Load Forecasting – consists of all components of peak load;
g. Grid Needs Assessment – consists of various capacity, reliability, and resiliency analyses substantiating investment needs;
h. Solution Selection Process – provides the criteria and methods used to identify, assess, compare. and select both traditional and non-traditional grid capital investments for implementation;
i. Capital Investment Plan – lists, prioritizes, and describes all planned
j. investments for a ten-year planning horizon; and
k. Long-Term Strategic Plan – provides an overview of strategic plans for the grid beyond a ten-year planning horizon.

For each of the content items above, please share what aspects of the submitted TSP Plan represent information that would be included in each of the proposed IDSP sections.

Please include exhibit and slide or page numbers for any content that would belong in each of the content sections.

OCC-566 Response:

For the purpose of answering this question, the Company is assuming that the IDSP referenced in the question is as described in PURA's proposed final decision issued on July 17, 2026, in Docket No. 21-05-15RE03, and as proposed and discussed by the EDCs in Technical Meetings #10 to #12. As designed therein, the IDSP is intended to be a cohesive, strategic plan for ensuring safe, reliable and resilient electric service for all customers while supporting state clean energy and decarbonization goals. Given the scope of the proposed IDSP, with expanded requirements for analytics, stakeholder engagement and review, the EDCs expressed concerns about the timeline, process and specific elements in Written Comments and Technical Sessions. Consequently, the TSP Plan aligns generally with the IDSP content, particularly in terms of the state of the system and investment plans to address current and projected needs, while also reflecting practical differences.

More specifically, the TSP aligns with proposed IDSP sections, as follows:

a. Executive Summary - identifies key points from each section of the document;
   Please refer to:
   Exhibit CLP-TSP-1
   Exhibit CLP-TSP-3: Page 3-7

b. Planning Policy – discusses relevant state and local goals and policies that inform grid planning;
   Please refer to:
   Exhibit CLP-TSP-2: Page 20-21

c. Current State of the System – provides an overview of existing grid conditions including but not limited to capacity, reliability, and DER integration issues;
   Please refer to:
   Exhibit CLP-TSP-2
   Exhibit CLP-TSP-3: Page 13-38

d. IDSP Methodology – explains the planning methods used to produce the IDSP;
   Please refer to:
   Exhibit CLP-TSP-2: Page 9-20, 24-28
   Exhibit CLP-TSP-3: Page 33-34, 83-92, 96-120, 138-139, 141-149

e. Stakeholder Engagement and Social Equity – specifies how stakeholders participate in the IDSP process, as well as social and environmental equity considerations;
   Please refer to:
   Exhibit CLP-ELP-1: Page 19, 29

f. Load Forecasting – consists of all components of peak load;
   Please refer to:
   Exhibit CLP-TSP-2: Page 20-24
   Exhibit CLP-TSP-3: Page 18-20, 91-92, 138

g. Grid Needs Assessment – consists of various capacity, reliability, and resiliency analyses substantiating investment needs;
   Please refer to:
   Exhibit CLP-TSP-3: Page 51, 56-81, 93-95, 102-106, 114-120, 142-149

h. Solution Selection Process – provides the criteria and methods used to identify, assess, compare. and select both traditional and non-traditional grid capital investments for implementation;
Please refer to:
Exhibit CLP-TSP-3: Page 88-90

i. Capital Investment Plan – lists, prioritizes, and describes all planned investments for a ten-year planning horizon.
Please refer to:
Exhibit CLP-TSP-1: Page 40-72;
Exhibit CLP-TSP-2: Page 46-48;
Exhibit CLP-TSP-3: Page 7-12, 45-81, 102-105, 107-149

j. Long-Term Strategic Plan – provides an overview of strategic plans for the grid beyond a ten-year planning horizon.
Please refer to:
Exhibit CLP-TSP-2: Page 20-21

Date Filed: October 26, 2026

Witness: John P. DiPaola-Tromba
Request from: Department of Energy and Environmental Protection

Question:

(Substation Transformers) Refer to Exhibit CLP-TSP-1, Exhibit CLP-TSP-1, pp. 55-56. Please explain the Company's rationale for targeting an average age of approximately 35 years when substation transformers typically have a design life of 40 years. Furthermore, please define "design life" and discuss whether there are any actions that can be taken to extend the life of these assets and whether the Company has taken such actions.

Response:

Based on industry experience, transformers can operate beyond their typical design life of 40 years, although the risk of failure exponentially increases after 70 years of service life, due to paper insulation degradation. OCC-596, Attachment 1 CONFIDENTIAL, provides a CIGRE study from 2024, showing the failure rate of transformers has a noticeable increase starting at 40 years and exponentially increases as the asset exceeds 65 years old. This study reviewed analysis of thousands of transformers including many voltage classes from around the world to build depth into the data available. OCC-596, Attachment 2 CONFIDENTIAL, is an EPRI paper discussing "Large Transformer End-of-Expected Life" that notes "the useful life of a large, oil-filled transformer is between 30 and 40 years with insulation or bus supports being the most likely to fail due to age. For the insulation, thermal aging of the paper insulation is the likely cause of failure."

OCC-596, Attachment 3, is a Department of Energy report from 2024, citing that large power transformers "are typically considered to have a design lifetime on the order of 40 years. In 2014, a DOE report estimated that the average age of LPTs in the North American grid was 38–40 years, indicating that a substantial fraction of those LPTs are at, or over, that design lifetime and that these LPTs will ultimately need to be replaced or refurbished. These industry research groups and others have provided basis within their published studies to support the concerns of failure with any transformer over 40 years in-service.

Based on this industry knowledge base, Eversource's Asset Health philosophy for transformers is to operate transformers to their maximum useful life, but plan to maintain a transformer fleet that does not exceed 70 years of age and maintains an *average age* of approximately 35 years. The objective is to find the balance between affordability and preventing an aged transformer fleet that approaches the "knee of the curve," resulting in failure rates that increase significantly. With a large portion of the transformer fleet being between 50 and 80 years old, as these transformers

continue to approach and exceed 70 years, the rate of failure will increase rapidly. Due to the complexity and time duration of procuring and replacing transformers, a significant increase in failures would result in the inability to maintain reliability by reactively replacing an increased volume of transformer failures.

Please refer to the response and attachments to OCC-596[i], for additional information on this topic.

In addition, Eversource employs several methods to both actively and passively monitor the health of all power transformers within its service area. Active and continuous monitoring methods include out-of-specification alarming. Remote alarming (if applicable) is conducted through the Eversource SCADA system with alarms existing for bushing monitoring, LTC trouble, dissolved gas, oil level alarms, and oil temperature alarms, among others. Per industry best practices, local alarming is performed through panel indication lamps with corresponding nameplate alarm descriptions and annunciation technologies such as bulb annunciators and Human Machine Interfaces (HMI's).

The preventive maintenance procedures for power transformers are documented within the Eversource Maintenance Program (EMP) 5.58 Station Transformers and Oil-Filled Shunt Reactors. The inspection and maintenance tasks are catalogued into three (3) categories which include a list of asset conditions for real-time condition monitoring, time-based regular inspections, and condition-based maintenance activities. These are described in more detail below:

Condition Monitoring: Various parameters related to power transformer health are actively monitored as applicable. The monitoring is performed both locally and remotely with local monitoring performed by individual equipment alarms and station annunciators. Remote monitoring is performed via Supervisory Control and Data Acquisition (SCADA) to enable real-time asset parameter output and SCADA equipment alarms. Such parameters include temperature, oil level, pressure, and load tap changer (LTC) status.

Time-Directed Maintenance and Inspections: Eversource has established multiple routine maintenance activities required to be performed for all power transformers within specific time intervals. These activities include monthly visual inspections, annual oil sampling including dissolved gas analysis (DGA), thermographic readings, LTC maintenance, and major maintenance activities. Major maintenance activities include power factor testing, bushing testing, excitation testing, confirmation of proper operation and integrity of pressure relief devices and ensuring all alarms operate properly.

Condition-Based Maintenance: These activities are on an as-needed basis when identified upon visual inspection, when performing time-directed maintenance activities, and when output from condition monitoring devices indicate outside normal operating values. Such activities include, but are not limited to, acoustic measurements, core grounding tests, leak repairs, and chassis repair.

Substation Technical Engineering leverages data collected by the CASCADE, PTX Analysis, and substation equipment databases to perform asset condition assessments of power transformers. The reports are based on the following six (6) parameters with recommendations for replacement by the Substation Technical Engineering team being based upon whether two (2) of the six parameters are considered high risk:

- Oil Analysis Results
    - DGA
    - Fluid Quality Analysis
    - Furan Analysis on Main Tanks
- Age
- Loading
- Maintenance History
- Historical Test Data
- Physical Inspection Findings

The above practices are applicable to all power transformers. Asset age and condition will prompt enhanced inspection, testing, monitoring, and maintenance as noted in the EMP toward the goal of maximizing the usable life of a transformer.

Historically the Company has effectively maximized the life of Transformers by extensive maintenance and monitoring practices, evidenced by the age demographics of the fleet which far exceed the typical design life of 40 years. While this practice continues, the risk profile of an aging fleet compounded by longer lead times and more challenging outage constraints has resulted in a need to initiate planned replacements, beyond the historical average of 1-2 transformer replacements per year, to minimize overall impact of a failed transformer and maximize efficiency. A typical transformer replacement can take from 2 to 5 years to plan and execute. From the time of identification of deteriorating health, the transformer will continue to degrade over the course of the project execution time period. While spares are an effective mitigation plan for emergent failures, it is not a “one-size fits all” long-term mitigation plan to address the fleet risk because depending on when the failure or urgent replacements occur, it may happen at a high-risk period of the year which cannot be controlled exposing the system and customers to a much higher risk. Allowing transformers to run to failure also poses a serious safety risk to both the public and utility

workers. Additionally, a failed transformer could cause damage to adjacent healthy equipment compounding the negative impact.

Prior to initiation of a transformer replacement project, the various subject matter experts (SMEs) will confer and review the nameplate data, maintenance records, and PTX scores of the unit. If a transformer is reviewed and a capital project is not to be initiated, the transformer is typically recommended to have further evaluation for maintenance mitigation of the found issue. This may include repairs or minor refurbishment actions that enable the power transformer to be reenergized and placed back in-service.

If the transformer is identified as requiring a capital project an initial funding is established and a project team assembled. The project team includes a team of SMEs and they are required to review the technical and financial feasibility of transformer replacement, transformer refurbishment, load transfer options, and usage of existing spare transformer inventory for a replacement. After the feasible options are developed, the project team will proceed with a formal review of the multiple feasible options within the procedures of the Eversource Solution Design Committee.

Please refer to the response and attachments to OCC-597[ii], for additional information on this topic.

Prior Referenced Responses:

[i] OCC-596 Question:

Refer to Exhibit CLP-TSP-1, at 55, "…plan to maintain a transformer fleet that does not exceed 70 years of age." Identify every law, regulation, manufacturer requirement, or mandatory engineering standard that requires a substation transformer to be retired at 40 years, 70 years, or any other specified age. If no such requirement exists, please confirm.

a. Provide all existing studies, analyses, and historical data relied upon by the Company to conclude that transformer failure risk increases rapidly as transformers approach or exceed 70 years of age. If the Company has not performed an empirical analysis using its transformer-failure experience, please justify.
b. Provide the Company data and analyses used to establish the transformer age thresholds or replacement criteria in the TSP, including the stated 40-year useful life and increased failure risk near 70 years. Include the age and cause of failure for each Company transformer that failed during the period covered by the analysis. If the criteria are not based on the Company's actual failure experience, identify the source on which they are based.

OCC-596 Response:

There are no laws, regulations, manufacturer requirements, or mandatory engineering standards that require substation transformers to be retired at a specific age. The age of a power transformer is one of the most important factors in assessing asset condition. Although actual service life varies widely depending on the manufacturer's design, quality of assembly, materials used, operating history, current operating conditions, and maintenance history, the average

expected life for an individual transformer is approximately 40 years according to industry consortiums, and manufacturers. International reliability surveys (i.e., CIGRE) report major failure rates on the order of ~0.3% per transformer-year across large populations, with failure behavior influenced by aging and asset condition. Industry asset-management guidance supports risk-based decision-making that balances failure risk and cost.

Eversource employs several methods to both actively and passively monitor the health of distribution power transformers within its service area. Active and continuous monitoring methods include out of specification alarming. Alarms may include indications for bushing monitoring (if applicable), LTC trouble, dissolved gas (if applicable), oil level alarms, and oil temperature alarms, among others.

This information along with periodic maintenance and testing reports provide data into Eversource's condition-based asset management methodology that draws on multiple sources including:

- Transformer nameplate characteristics
- Oil quality and DGA trends
- Abnormal thermal, electrical, or core indicators derived from PTX health modeling
- Maintenance and inspection records
- Power Factor Testing

Eversource utilizes a detailed asset health score generated through the Electric Power Research Institute (EPRI) PTX tool to assess power transformer asset health. OCC-596, Attachment 4 CONFIDENTIAL, is a technical guide to the EPRI Power Transformer Expert System (PTX). The PTX tool evaluates normal degradation, abnormal operating conditions, oil quality, and age to produce two critical indicators: the Long-Term Health Index (LTI) and the Short-Term Health Index (STI). The PTX health index is measured in the range of 0 to 1, with 0 meaning healthy and 1 needing immediate replacement. A value greater than 0.5 is considered poor health, such that if repair/replacement is not performed the transformer will continue to decline leading to equipment failure.

Eversource has 27 transformers in CT, or about 8.6% of the fleet, that fall within the range considered to be in poor condition. This means that without repair or replacement, their condition is expected to continue declining, increasing the risk of equipment failure. As a result, Eversource continues to prioritize and initiate replacement projects for these transformers.

Attachments included note that multiple industry sources discuss aging and failure rates of substation power transformers.

- OCC-596, Attachment 1 CONFIDENTIAL, A2 Cigre Brochure 939 AC Transformer Reliability
- OCC-596, Attachment 2 CONFIDENTIAL, 1013566 Plant Support Engineering Large Transformer End of Expected Life Considerations and the Need for Planning
- OCC-596, Attachment 3, EXEC-2022-001242 - Large Power Transformer Resilience Report 7-10-24
- OCC-596, Attachment 4 CONFIDENTIAL, 3002026877_Power Transformer Expert System (PTX) Software Application Guide_ Introduction to PTX, Overview, Technical Basis and Application Information

Based on industry experience, while transformers can operate beyond their typical design life of 40 years, the risk of failure exponentially increases after 70 years of service life, due to paper insulation degradation. OCC-596, Attachment 1 CONFIDENTIAL, a CIGRE study from 2024, shows the failure rate of transformers has a noticeable increase starting at 40 years and exponentially increases as the asset exceeds 65 years old. This study reviewed analysis of thousands of transformers including many voltage classes from around the world to build depth into the data available. OCC-596, Attachment 2 CONFIDENTIAL is an EPRI paper discussing "Large Transformer End-of-Expected Life" which notes "the useful life of a large, oil-filled transformer is between 30 and 40 years with insulation

or bus supports being the most likely to fail due to age. For the insulation, thermal aging of the paper insulation is the likely cause of failure."

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As a result, Eversource's Asset Health philosophy for transformers is to operate transformers to their maximum useful life, but plan to maintain a transformer fleet that does not exceed 70 years of age and an average age of approximately 35 years. The objective is to find the balance between affordability and preventing an aged transformer fleet that approaches the "knee of the curve" which results in failure rates that increase significantly. With a large portion of the transformer fleet being between 50 and 80 years old, as these transformers continue to approach and exceed 70 years, the rate of failure will increase rapidly. Due to the complexity and time duration of procuring and replacing transformers, a significant increase in failures would result in the inability to maintain reliability by reactively replacing an increased volume of transformer failures.

The six most recent failures of transformers in CT were all attributed to internal failures of the transformer. The ages of the failed transformers were 32, 50, 52, 52, 56, and 83 years old at the time of the failure.

[ii] OCC-597 Question:

Refer to Exhibit CLP-TSP-1, at 55. For each proposed proactive replacement, identify whether the Company evaluated continued operation through enhanced inspection, testing, monitoring, maintenance, refurbishment, loading limits, load transfer, or use of a spare transformer. Provide each existing analysis and state whether it found that replacement could be deferred by one, three, or five years. If no deferral or life-extension or alternate analysis was performed, please confirm the reason.

OCC-597 Response:

Eversource employs several methods to both actively and passively monitor the health of all power transformers within its service area. Active and continuous monitoring methods include out-of-specification alarming. Remote alarming (if applicable) is conducted through the Eversource SCADA system with alarms existing for bushing monitoring, LTC trouble, dissolved gas, oil level alarms, and oil temperature alarms, among others. Per industry best practices, local alarming is performed through panel indication lamps with corresponding nameplate alarm descriptions and annunciation technologies such as bulb annunciators and Human Machine Interfaces (HMI's).

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Substation Technical Engineering leverages data collected by the CASCADE, PTX Analysis, and substation equipment databases to perform asset condition assessments of power transformers. The reports are based on the following six (6) parameters with recommendations for replacement by the Substation Technical Engineering team being based upon whether two (2) of the following (6) parameters are considered high risk:

- Oil Analysis Results
    - o DGA
    - o Fluid Quality Analysis
    - o Furan Analysis on Main Tanks
- Age
- Loading
- Maintenance History
- Historical Test Data
- Physical Inspection Findings

The above practices are applicable to all power transformers. Asset age and condition will prompt enhanced inspection, testing, monitoring, and maintenance as noted in the EMP toward the goal of maximizing the usable life of a transformer.

Historically the Company has effectively maximized the life of Transformers by extensive maintenance and monitoring practices, evidenced by the age demographics of the fleet which far exceed the typical design life of 40 years. While this practice continues, the risk profile of an aging fleet compounded by longer lead times and more challenging outage constraints has resulted in a need to initiate planned replacements, beyond the historical average of 1-2 transformer replacements per year, to minimize overall impact of a failed transformer and maximize efficiency. A typical transformer replacement can take from 2 to 5 years to plan and execute. From the time of identification of deteriorating health, the transformer will continue to degrade over the course of the project execution time period. While spares are an effective mitigation plan for emergent failures, it is not a “one-size fits all” long-term mitigation plan to address the fleet risk because depending on when the failure or urgent replacements occur, it may happen at a high-risk period of the year which cannot be controlled exposing the system and customers to a much higher risk. Allowing transformers to run to failure also poses a serious safety risk to both the public and utility workers. Additionally a failed transformer could cause damage to adjacent healthy equipment compounding the negative impact.

Prior to initiation of a transformer replacement project, the various subject matter experts (SMEs) will confer and review the nameplate data, maintenance records, and PTX scores of the unit. If a transformer is reviewed and a capital project is not to be initiated, the transformer is typically recommended to have further evaluation for maintenance

mitigation of the found issue. This may include repairs or minor refurbishment actions that enable the power transformer to be reenergized and placed back in-service.

If the transformer is identified as requiring a capital project an initial funding is established and a project team assembled. The project team includes various SMEs and they are required to review the technical and financial feasibility of transformer replacement, transformer refurbishment, load transfer options, and usage of existing spare transformer inventory for a replacement. After the feasible options are developed, the project team will proceed with a formal review of the multiple feasible options within the procedures of the Eversource Solution Design Committee.

Using the nameplate data with age and ratings combined with the PTX scores, the power transformers noted in Exhibit CLP-TSP-1, at 55 have been identified to proceed with the initial capital project evaluation within the Targeted System Plan. As these evaluations are completed, the power transformers will be prioritized and projects initiated as confirmed. The project sequencing and deferral options will be evaluated within this review.

The two active and ongoing projects for transformer replacements included within the Targeted System Plan followed the processes noted above, were prioritized within the project portfolio, and are planned to be placed in-service in 2028.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Load/DER Forecast) Refer to Exhibit CLP-TSP-1, Exhibit CLP-TSP-1. Please provide all assumptions the Company relied on for its TSP capacity planning, including historical and forecasted substation and circuit peak loads, specific large customer changes, planned circuit changes and estimated growth and retirement of distributed energy resources and energy efficiency.

Response:

The Company utilizes its bulk-substation peak load forecasts for distribution planning purposes. Please refer to the Company's response to OCC-591[i] for details on assumptions around forecasted loads, customer growth, large customer loads, energy efficiency and more.

Prior Referenced Response:

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[i] OCC-591 Question:

Refer to Exhibit CLP-TSP-1 at 49.

a. Provide all load forecast models supporting each proposed line and substation capacity project.
b. Provide all assumptions for EV, heat pump, solar, storage, C&I load growth, data centers, step loads, and economic development load.
c. Identify any capacity projects that could be deferred by NWA, DERMS, AMI-enabled load management, or targeted demand response.
d. For each proposed capacity project, quantify the forecast overload in MVA, MW, amperes and the number of violating hours in each year.
e. For every project passing or nearly failing NWA screening, provide the full benefit-cost analysis, all sensitivities, evaluation workpapers and comparison of the NWA with load transfer, staged construction and the traditional solution. Quantify the present value of deferral for one, three, five and ten years.

OCC-591 Response:

a. Please refer to OCC-591, Attachment 1 CONFIDENTIAL, for a 10-year forecast for each identified substation capacity project. Long-term load forecasts are not generated at the individual feeder level. Line capacity projects are based on actual metered data versus a forecast. Feeder level forecasts become inherently less accurate as stochastic customer behavior of just a few customers can swing forecast results wildly and cause large errors, as compared to large groups where such effects average out. In addition, unlike substation

investments, feeder upgrades can be done on a short turnaround time, allowing the Company to respond to actual loading on the system rather than forecasts.

b. The individual substation forecasts are located within each worksheet in OCC-591, Attachment 1 CONFIDENTIAL, and are broken into the individual categories the Company tracks.

For details on known, firm distribution connected data centers in the Company's forecast, this would be factored into the Step Loads category. Please refer to the Company's response to information request OCC-465 for details on how the Company accounts for Step Loads.

C & I load growth and economic development load is aggregated into the Trend category unless they are individual requests for interconnection that are considered step loads.

Please refer to the Company's response to CLF-SC-022 request on how the Company accounts for EV, heat pumps, and solar.

c. The substation capacity projects identified in the workbooks are in various stages of the project-approval process. None of the projects have reached a stage that would have received a detailed NWA analysis to date. As these projects proceed through the solution selection and engineering stages, NWA and other alternatives will be vetted. The results will be submitted during the annual grid needs filing as part of the NWS docket.

The line capacity projects identified currently exceed the planning criteria based on metered data and NWS solutions were analyzed as alternatives to traditional line projects. No existing line capacity projects could be deferred by NWA, DERMS, AMI-enabled load management, or targeted demand response. The Company submitted all capital projects to the process monitor as part of Docket No. 25-08-08 and the ongoing Docket No. 26-08-08.

d. Please refer to OCC-591, Attachment 1, for a 10-year forecast for each identified substation capacity project. Each proposed capacity project within the attachment, shows the forecast overload in MVA. The number of violating hours in each year has not yet been analyzed but this would be conducted during the NWS program process.

Forecasting is not performed at the distribution line level as these capacity projects can be executed in a short timeframe when compared to substation capacity projects. Please refer to OCC-591, Attachment 2, for the proposed line capacity projects based on actual metered data, and circuit overloads in MVA and Amps. The number of violating hours in each year is not available.

e. As part of that PURA approved process, the complete Benefit Cost Analysis (BCA) is available only after projects advance to a competitive solicitation, as the analysis relies on pricing and solution details provided by developers through the solicitation process. Without developer-specific cost information, a comprehensive BCA cannot be completed. As noted in PURA's Final Decision in Docket No. 26-08-08, no project was ordered to proceed with a competitive solicitation.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-1 pp. 29-30. The Company implies a change in the load growth pattern that is changing the investment needs. Please provide examples of this and identify, if possible, what is causing the growth and if the growth is happening in areas with a definable set of characteristics.

Response:

In the referenced section of CLP-TSP-1 the Company outlines a couple of key items:

1. Over the past decade, the Company has used all available methods to increase the load-serving ability of the distribution system by transferring loads from heavily loaded substations and circuits to neighboring infrastructure. On this point, it is important to note that load transfer between substations does not increase system capacity, but instead, actually diminishes operational flexibility by using transfer capacity intended for emergency conditions to serve load. Load transfer also increases area-wide constraints and risks by moving load to substations outside the natural service area and places the system in a less reliable, off-nominal configuration, compared to the native design. The result of these actions is that, over time, on large portions of the system, the Company is now faced with very little spare capacity and room to maneuver.

2. A compounding effect of Item #1, above, is that load growth, especially driven by larger commercial developments, such as shipping and storage facilities that require significant amounts of land, generally materializes in electrically weaker areas where the infrastructure design is a function of lower-demand rural use, which is now causing these types of substations to be loaded beyond respective thermal capacity limits very quickly. With the area electric system so constrained (as discussed in Item #1), the Company has limited maneuverability to accommodate large new loads and economic growth, which results in the need for substation upgrades to maintain safe, reliable operation of the system and provide the required quality of service for customers.

3. Another effect is that DER growth has developed in a proportionally inverse manner to load density and consequently to infrastructure strength and capacity. Land is the single largest indicator for large-scale solar development potential and land is cheap and abundant

in most areas where electric demand is low. This potentially leads to large amounts of generation injected into areas of the system that were not designed for the ensuing thermal capacity loading on distribution equipment.

Date Filed: October 28, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-1 pp. 29-30. Has the Company raised this change in load growth pattern and the cost implications in a proceeding before the Authority in any of the Equitable Modern Grid Dockets and annual dockets that were the outgrowth of those dockets. Also include in your response, an explanation of:

a. the cost implications to non-participating customers as a result of the phenomena described;
b. are the costs described here included within the interconnection costs of the DERs that are interconnecting in these areas;
c. is whether or not the Company is proposing that the costs described here should be borne by all ratepayers or the interconnecting customers.

Response:

Please refer to the Company's response to BETP-029[i] for the Company's response. Yes, the Company has raised these issues in various proceedings before the Authority, such as 22-06-29 RE01.

a. The testimony does not describe a specific cost impact to non-participating customers. Rather, it explains how changing patterns of customer load growth and distributed energy resource ("DER") development are creating new planning challenges for the distribution system.

   To the extent infrastructure investments are required to maintain safe and reliable service and support customer load growth, those investments are evaluated and implemented in accordance with existing distribution planning practices and cost recovery mechanisms.

   In contrast, upgrades required solely to accommodate the interconnection of a DER facility are generally the responsibility of the interconnecting customer. As discussed elsewhere in this filing, the proposed SHARE framework is intended to facilitate a more equitable allocation of DER-related interconnection costs among participating beneficiaries and does not shift those costs to non-participating customers.

b. DER developers bear the cost of system upgrades required to interconnect a DER facility. Under the current interconnection framework, when a DER project triggers the need for

upgrades to accommodate its interconnection, those upgrade costs are generally assigned to the interconnecting customer. As a result, the first developer whose project causes a system constraint to be identified may be responsible for funding upgrades that subsequently provide benefits to future interconnection customers. Here is a first pass at this:

For localized distribution line upgrades, this cost allocation approach may not be prohibitively expensive. However, for larger infrastructure investments, such as substation upgrades required to mitigate hosting-capacity limitations, the costs can become substantial and may present a barrier to interconnection for individual developers.

The proposed SHARE framework is intended to address this issue by allowing the Company to facilitate a group study for multiple interested interconnection customers seeking capacity within the same constrained area. Through this process, the costs of interconnection upgrades identified through the group study would be allocated among participating DER developers on a pro-rata basis. Accordingly, the types of costs described in the testimony would continue to be borne by interconnecting customers; however, under the proposed SHARE framework, such costs could be shared among multiple participating beneficiaries rather than being assigned to a single developer under the traditional interconnection process.

c. The question appears to be mixing two different aspects of the reference into a single bucket for discussion. First, for DER development, the Company's SHARE proposal would allocate costs based on a beneficiary pays principle.

New load in the region is required to pay, net of any revenue credits, cost for their interconnection. Substations which run out of available load serving capacity, and if triggered by load growth, will be paid for by ratepayers unless they can be part of a SHARE region – in which it then goes back to beneficiary allocation of cost.

The Company is not proposing that the costs of DER-driven interconnection upgrades be borne by all ratepayers. Rather, the Company proposes that such costs continue to be borne by the interconnecting customers that benefit from the additional hosting capacity created by those upgrades.

The proposed SHARE framework modifies the allocation of such costs among participating DER developers but does not alter the underlying beneficiary-pays principle. Under the current interconnection process, the first developer to trigger a system constraint may be required to fund the full cost of a necessary upgrade. Under the proposed SHARE framework, the Company would facilitate a group study and allocate the costs of identified interconnection upgrades among participating DER developers on a pro-rata basis.

To the extent a project also addresses separate load-serving, reliability, or other system needs, those benefits would continue to be evaluated consistent with existing planning and cost-allocation practices. The Company's proposal is intended to ensure that the costs associated with creating additional DER hosting capacity are borne by the customers benefiting from that capacity while allowing project implementation costs to be shared more efficiently among participating stakeholders.

Prior Referenced Response:

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[i] BETP-029 Question:

Refer to Exhibit CLP-TSP-1 pp. 29-30. The Company implies a change in the load growth pattern that is changing the investment needs. Please provide examples of this and identify, if possible, what is causing the growth and if the growth is happening in areas with a definable set of characteristics.

BETP-029 Response:

In the referenced section of CLP-TSP-1 the Company outlines a couple of key items:

1. Over the past decade, the Company has used all available methods to increase the load-serving ability of the distribution system by transferring loads from heavily loaded substations and circuits to neighboring infrastructure. On this point, it is important to note that load transfer between substations does not increase system capacity, but instead, actually diminishes operational flexibility by using transfer capacity intended for emergency conditions to serve load. Load transfer also increases area-wide constraints and risks by moving load to substations outside the natural service area and places the system in a less reliable, off-nominal configuration, compared to the native design. The result of these actions is that, over time, on large portions of the system, the Company is now faced with very little spare capacity and room to maneuver.

2. A compounding effect of Item #1, above, is that load growth, especially driven by larger commercial developments, such as shipping and storage facilities that require significant amounts of land, generally materializes in electrically weaker areas where the infrastructure design is a function of lower-demand rural use, which is now causing these types of substations to be loaded beyond respective thermal capacity limits very quickly. With the area electric system so constrained (as discussed in Item #1), the Company has limited maneuverability to accommodate large new loads and economic growth, which results in the need for substation upgrades to maintain safe, reliable operation of the system and provide the required quality of service for customers.

3. Another effect is that DER growth has developed in a proportionally inverse manner to load density and consequently to infrastructure strength and capacity. Land is the single largest indicator for large-scale solar development potential and land is cheap and abundant in most areas where electric demand is low. This potentially leads to large amounts of generation injected into areas of the system that were not designed for the ensuing thermal capacity loading on distribution equipment.

Date Filed: October 28, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-1 p. 32. Please provide additional information regarding the specific electrical system limitations that the Canadian Company required. Please explain what upgrades were needed and the costs associated with the necessary upgrades?

Response:

The testimony cited in the question was intended to illustrate the challenges associated with serving very large new load requests in portions of eastern Connecticut and was not intended to imply that the Company had completed a detailed engineering assessment or developed a formal estimate of the upgrades and costs required to serve the project. Rather, the testimony reflected a preliminary assessment that the Company's existing infrastructure could not support the customer's requested load within the customer's required timeframe.

The prospective customer was evaluating a manufacturing facility with anticipated electrical demand of a magnitude that would ultimately exceed the capabilities of the existing local distribution system and likely require a dedicated bulk power supply solution. Based on preliminary discussions, the Company determined that sufficient capacity could not be provided within the customer's required timeframe and that available substation headroom in the area was insufficient to support a practical phased-service approach for initial operations pending development of longer-term infrastructure. Given those constraints, the customer did not pursue the proposed development further, and the project did not progress to a stage at which the Company would perform a detailed engineering analysis or develop a formal estimate of the required upgrades and associated costs.

The limitations identified during these preliminary discussions were driven by broader distribution system characteristics in portions of eastern Connecticut, where the electric grid serves a largely rural geography. In many areas, substations are widely spaced, circuit lengths are long, and existing infrastructure was designed to support historically lower levels of customer demand. As a result, available electrical capacity can be limited, particularly in locations experiencing significant commercial and industrial growth.

In recent years, the magnitude of individual load requests has increased substantially compared to historic levels. This trend is being driven by factors such as the expansion of manufacturing

facilities, growth in large-scale warehouse and distribution centers, deployment of electric vehicle charging infrastructure, increased adoption of electric heating technologies such as heat pumps, and greater use of automated and robotic industrial processes. These projects often require significantly larger electrical service capacities than traditional commercial developments.

When new load requests exceed the available capacity of the local distribution system, upgrades may be required to maintain system reliability, voltage performance, and compliance with planning and operating criteria. Depending on the location and magnitude of the requested load, necessary upgrades can include distribution feeder reinforcements, conductor replacements, installation of voltage support equipment, substation transformer upgrades, expansion of existing substations, or construction of new distribution infrastructure.

The specific upgrades required and the associated costs are highly dependent on the location of the proposed load, the amount of available capacity on the existing system, and the overall magnitude of the requested demand. Consequently, upgrade costs can vary significantly from project to project, ranging from relatively modest distribution modifications to substantial investments in substation and feeder infrastructure where existing system capacity is insufficient to accommodate the requested load.

For the specific project under discussion, preliminary assessments indicated that serving the customer's full long-term load would require significant infrastructure development beyond the capabilities of the existing local distribution system. In addition, available substation capacity in the area was insufficient to support a practical phased-service approach that could accommodate the customer's interim operational needs while longer-term infrastructure solutions were planned and constructed. As a result, the Company's assessment was that it could not support the customer's anticipated load within the customer's required timeframe.

Eversource remains willing to work with project developers to evaluate potential service solutions as projects advance. Should the developer elect to proceed with a high-level engineering study, Eversource will continue to assess infrastructure requirements, available service alternatives, project phasing opportunities, and associated costs needed to reliably accommodate the proposed development.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

Refer to Exhibit CLP-TSP-1, p. 34. The Company's model that includes the past 20 years of upgrades and shows the benefits of every dollar invested in terms of SAIDI and SAIFI. Has the Company identified any trend on reliability improvement and money invested? Specifically, are there diminishing returns on investment at a certain point of reliably? Are there any inflection points?

Response:

The Company's reliability optimization model evaluates potential reliability projects by estimating their expected reliability benefits, including SAIDI and SAIFI improvements, relative to their cost. This model has identified that, over time, diminishing returns of reliability projects are expected.

The model ranks potential investments according to their cost effectiveness. Consistent with reliability planning principles, the projects with the greatest expected reliability benefit per dollar invested are generally identified first. As additional projects are considered, the incremental reliability benefit achieved per dollar invested typically declines. In other words, over time, progressively larger investments are generally required to maintain or improve reliability performance.

Not all projects that improve reliability should be identified through the ReBOT tool, whose focus is on zones with multiple feasible mitigations. Potential reliability improvements evolve over time due to factors such as asset aging, changing system conditions, weather impacts, vegetation growth, and the inherently stochastic nature of outage events. Also, as previously identified projects are completed, and updated reliability performance data are integrated into the tool, new opportunities for cost-effective reliability improvements may emerge. Consequently, the Company continually evaluates reliability investment opportunities and assesses their expected benefits and costs as part of its ongoing planning process.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-2 p. 88, Exhibit CLP-TSP-4. Did the Company submit Exhibit CLP-TSP-4 as a compliance filing to Order No. 12 on Docket No. 17-12-03RE08, on or before the deadline of October 7, 2022? If not, please explain why.

Response:

Order No. 12, in Docket No. 17-12-03RE08 specifies that the EDCs shall "submit for Authority review and approval a detailed scope of work, timeline and anticipated budget for completing its Climate Vulnerability Study…" (emphasis added). Eversource Energy and Avangrid jointly submitted a compliance filing in compliance of this Order on October 7, 2022.

Please refer to BETP-033, Attachment 1, for a copy of this compliance filing.

There is no Order in Docket No. 17-12-03RE08 that directs the EDCs to submit the actual completed Climate Vulnerability Study by a specific deadline, except that, Order No. 13 directs the EDCs to utilize the Climate Vulnerability Study results as part of the Reliability and Resilience Frameworks in the next rate case.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4. In the Final Decision of Docket No. 17-12-03RE08, on p. 79, the Authority instructed the Company to consider the findings of three climate change reports that were specific to Connecticut. Can the Company explain how these three reports were consulted and, if at all, incorporated into the findings of this exhibit?

Response:

The Company reviewed the three climate change reports and all reports are Connecticut specific. From a methodology and process standpoint, the Company did not find that these three climate change reports are contradictory to its Climate Vulnerability Assessment. However, the Connecticut Physical Climate Science Assessment Report and the CIRCA Sea Level Rise in Connecticut Final Report are older reports, consistent with older Global Climate Models than the ones used in the Company's Climate Vulnerability Assessment (CVA). Further, because the Company's ultimate interest is to evaluate the need for a targeted climate adaptation plan, it is important that a CVA include projections for multiple years to prioritize based on the projected changes over time. For example, the CIRCA Sea Level Rise is published for 2050 only. For efficiency and consistency reasons, the Company proceeded with a comprehensive climate study across its tristate territory.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4, p. 13. Please define and explain an "optimal climate adaptation plan," and describe how this plan can be developed and implemented within the Company's estimated 18-month schedule from approval?

a. Can the Company explain why Phase 3 of the Vulnerability Assessment remains incomplete as of the date of this interrogatory issuance?

Response:

Although what the "18-month schedule" is referring to and what approval is referred to, the Company's reference to optimizing the climate adaptation plan refers to proceeding with investments that are effective and efficient in increasing the resilience of the system. As outlined in the analysis of the risk in CLP-TSP-4, the climate conditions assessed as part of the climate vulnerability study are for 2050. This gives the Company sufficient time to deploy potential needed climate adaptation mitigations. The Company notes that recent studies indicate that the pace of climate change may dictate that such analyses are repeated in later years or are performed regularly with some periodicity that is appropriate to capture changes in climate conditions from the previous study. This is of course dependent on the periodicity of the Global Climate Models (GCM) updates.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4. Did the Company review the 2025 Connecticut Grid Resilience Assessment, issued by the University of Connecticut Eversource Center, as part of its preparation of the Climate Vulnerability Study?

a. Did the Company participate in the development of the 2025 Connecticut Grid Resilience Assessment

Response:

Please refer to CLP-TSP-4, at 10. The climate hazard assessment was completed in early 2025. The 2025 Connecticut Grid Resilience Assessment was published in November 2025.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4. Did the Company consult UConn Connecticut Institute for Resilience & Climate Adaptation's (UConn CIRCA) maps to assess potential future coastal flooding. If no, please explain why.

Response:

For consistency and cost effectiveness of conducting the Climate Vulnerability Study, the Company performed a tri-state study, covering its territory across New Hampshire, Massachusetts and Connecticut and as a result, state-specific studies could not be used as inputs. However, the underlying model used in CIRCA maps is from NOAA, so the model used in CVA is the core of the CIRCA maps.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4 p.45. Please explain the methodologies used and why these approaches were taken in the "Engineering Risk Assessment" section of the Company's Climate Vulnerability Assessment. Additionally, please identify the sources and resources that behind the methodologies chosen in this study.

Response:

The Company understands this question to refer to the risk quantification in CLP-TSP-4 that shows risk as the product of threat, vulnerability and consequence. This quantification of risk is considered industry standard, as supported by the references provided on the same page. Please refer to BETP-038, Attachment 1.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4, p.58. Please identify the sources and resources used to support the "Sensitivity Analysis."

a. Please explain the difference between the Risk MAP and Flood Insurance Rate Maps.

Response:

Please refer to Risk Mapping, Assessment and Planning (Risk MAP) | FEMA.gov. Per FEMA's webpage, MAP, which stands for Mapping, Assessment and Planning is the process to create maps that visualize flood risk. These maps are called Flood Insurance Rate Maps or FIRMs.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4 pp. 28, 50-53. Why did the Company not include extratropical cyclones in the analysis of storm surge?

a. Did the Company base storm surge levels on the Saffir-Simpson classification?
b. Did the Company consider other factors that impact storm surge levels not captured by Saffir-Simpson? If yes, please describe the factors and explain why these factors were considered.

Response:

a. Yes, the Company's reference to Category 1, 2 and 3 of storms is consistent with NOAA's SLOSH maps that are based on the Saffir-Simpson classification.

b. No, the Company did not. The Company is not aware of any available data that projects storm surge from extratropical cyclones, hence this was not part of the coastal flooding analyses.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4 p. 59. Please provide datasets, sources, and resources used to record the wind speed data and please include the following:

a. Exact location and gauge height;
b. maintenance and calibration records;
c. any additional relevant data that supports the records for these wind speeds.

Response:

The Company did not perform wind speed recordings. The historical values reported in CLP-TSP-4 utilize DTN's Connecticut weather stations datasets.

Date Filed: October 26, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Department of Energy and Environmental Protection

Question:

(Climate Change Vulnerability Study) Refer to Exhibit CLP-TSP-4 p. 29-44. Please explain the goal of the two case study extreme event scenarios and how they relate to understanding the Company's climate change vulnerability.

Response:

The goal of these two extreme event scenarios is to supplement the global climate model-based projections of climate hazards and provide a more comprehensive view of the potential risks of extreme events and the associated expected value of climate adaptation. The global climate model-based projections of climate hazards have technical limitations on their extension to extreme events. For example, the two extreme events studied use historical events to contemplate a plausible sequence of occurrences of climate hazard maxima and assess the increase in risk when this happens back-to-back, as opposed to global climate model-based projections of climate hazards that can only evaluate these hazards independently.

Date Filed: October 27, 2026

Witness: Jared A. Lawrence, Shamus O'Brien, Edward A. Davis and Kimberly R. Parsons
Request from: Department of Energy and Environmental Protection

Question:

(TVR interim or bridge offerings) Refer to Exhibit CLP-AMI-1, pp. 11-12 n.1, and Exhibit CLP-AMI-2, pp. 80-82. Please identify the residential and commercial rate offerings the Company expects to propose as interim or bridge solutions by the October 1, 2027, deadline in Conn. Gen. Stat. Sec. 16-243n and explain how each proposal will address:

a. default enrollment with an opt-out;
b. applicable retail rate components;
c. seasonal and on-peak/off-peak design;
d. customer protections;
e. customer education; and
f. empirical support for the rate differential.

Response:

Details of these offerings and how each of the following items will be addressed will be provided in the Company's proposed interim rate filing with PURA. The Company notes that proposed rates for the interim, bridge solution are expected to be subject to the same metering and billing capabilities and constraints as with current rates. Current structures and the outcomes for rates in the current rate case are expected to inform and provide the foundation for proposed interim or bridge rate solutions. The Company is not providing its proposed interim solutions at this time but is mindful of the referenced statutory requirements represented in the questions posed and offers the following.

a. The Company's current rates, structures and metering and billing capabilities are anticipated to provide the foundation for proposed interim solutions. Given that current rates consist of optional residential and a combination of optional and mandatory commercial class time-varying rates that apply to certain components of rates, a proposal for moving to new, default rate structures will require consideration of impacts due to changes in rates and a transition plan to migrate customers to proposed new structures.

b. Current time-varying structures apply to the transmission and generation supply components of service. The Company anticipates that such current rate structures and any changes determined within the current Distribution rate case will provide the foundation

for proposed interim rates. The Company will address proposed interim rate solutions that require changes to these components of service, and that may apply to Distribution rates, as part of its proposed interim rate submittal.

c. Current time-varying rates employ a 2-period, time-of-day (i.e., peak vs. off-peak) fixed rate structure that is expected to provide the basis for future time-varying structures for the proposed interim rate design. Such structures may be proposed on a seasonal basis for some components of service in the proposed interim rate design.

d. The Company expects consumer protections afforded by the Company's tariff (i.e., the terms and conditions for distribution service and for generation supply), "consideration for principles of gradualism and customer acceptance" in proposed rates, and further "established exceptions as deemed appropriate by the authority, including, but not limited to, for medically protected and financial hardship customers", pursuant to Conn. Gen. Stat. Sec. 16-243n, Section 20, part (b)(4), effective July 1, 2025, will be addressed as part of the Company's proposed interim rate design.

e. A marketing, education and outreach plan for residential and commercial customers will be developed to educate customers about any interim or bridge solutions proposed, as those options become available, to inform them of the benefits, necessary behavior modifications and the steps to enroll or unenroll as necessary.

f. Empirical support for the rate differential for peak and off-peak rates being addressed in the current Distribution rate case, including calculations and applications in proposed rate design and as informed by the marginal cost analysis performed as part of the current case, is expected to provide insight into the cost basis for setting a peak and off-peak differential for distribution and transmission rates anticipated to be to be developed and submitted as part of the October 1, 2027 filing. Consideration of differentials reflected in statutory or regulatory constraints and requirements are expected to be reflected in the Company's proposed generation supply rates portion of service in the proposed interim rate solution.

Date Filed: October 27, 2026

Witness: Jared A. Lawrence
Request from: Department of Energy and Environmental Protection

Question:

(TVR interim or bridge offerings) Refer to Exhibit CLP-AMI-1, pp. 11-12 n.1, and Exhibit CLP-AMI-2, pp. 80-82. Provide the process that Eversource anticipates utilizing for replacing or transitioning the interim TVR bridge offerings to the ultimate AMI-enabled time-varying rates proposed by Eversource to be implemented following AMI deployment.

Response:

The discussion in the section, Time-Varying Rates Implementation Timeline, on pages 80-82 of Exhibit CLP-AMI-2 provides an outline of the process and approach proposed to be employed. The Company plans to include an updated outline and narrative regarding this process, reflecting the outcome and implications from the current rate case that may affect the deployment of AMI or the corresponding implementation timeline as part of its proposed interim rate proposal.

Date Filed: October 26, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Department of Energy and Environmental Protection

Question:

(Rate 7) For calendar years 2020 through 2025, provide a summary table for residential Rate 7 showing:

a. year-end enrollment;
b. new enrollment and departures;
c. average annual on-peak and off-peak usage per customer; and
d. the average bill under Rate 7 compared with the bill the same customers would have received under Rate 1.

Response:

Please refer to BETP-045, Attachment 1, for the requested information for subparts (a), (c), and (d). The Company is unable to provide the requested information for subpart (b) due to limitations in queries to identify account changes specifically resulting from a change in rate class.

Date Filed: October 27, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Department of Energy and Environmental Protection

Question:

(Rate 7) Within the past five years, has the Company performed, or has the Company retained a consultant to perform, any analysis of its current Rate 7 customer usage. If yes, please describe the analysis performed, who performed the analysis and the conclusions reached from that analysis. Please then explain how those findings informed the proposed Rate 7 design in this case and, if known, will inform the Company's October 1, 2027 TVR application.

Response:

The Company has performed and utilized analysis of customer usage and demand for the 2025 Test Year (i.e., load research analysis) and performed a class bill frequency analysis (see Exhibit CLP-RATES-4) as part of this case. The Company has also analyzed billed usage and developed proposed, rate year billing determinants reflecting the changes to usage forecast for the rate year, as applied to billing determinants and the design of proposed rates. The Company's consultant, Amparo Nieto, has also conducted a marginal cost-of-service study and allocated cost of service study, which included the evaluation of Distribution costs, their class allocations, and the marginal cost to provide Distribution service to Rate 7. The allocation of revenue requirements and design of rates for Rate 7, both at a class level and on a time-of-day basis, are based on the results of these analyses, as detailed in the Company's rate proposal (see Exhibits CLP-RATES-1, CLP-ACOS-1 and CLP-MCOS-1, and corresponding exhibits referenced therein). As indicated in the Company's response to BETP-43[i], the current and proposed rate design for all components of service for residential and commercial rate classes, and thereby, Rate 7, may provide the foundation and basis for development of the Company's October 1, 2027 TVR application, including the aspects of that application relevant to Rate 7. The marginal cost study results provides a source of empirical data and may be an important part of any consideration for the design of any potential time-varying Distribution rate proposal submitted for Rate 7, as part of the October 1, 2017 application. The use of these or other findings may be reflected in that application.

Prior Referenced Response:

[i] BETP-043 Question:

(TVR interim or bridge offerings) Refer to Exhibit CLP-AMI-1, pp. 11-12 n.1, and Exhibit CLP-AMI-2, pp. 80-82. Please identify the residential and commercial rate offerings the Company expects to propose as interim or bridge

solutions by the October 1, 2027, deadline in Conn. Gen. Stat. Sec. 16-243n and explain how each proposal will address:

a. default enrollment with an opt-out;
b. applicable retail rate components;
c. seasonal and on-peak/off-peak design;
d. customer protections;
e. customer education; and
f. empirical support for the rate differential.

BETP-043 Response:

Details of these offerings and how each of the following items will be addressed will be provided in the Company's proposed interim rate filing with PURA. The Company notes that proposed rates for the interim, bridge solution are expected to be subject to the same metering and billing capabilities and constraints as with current rates. Current structures and the outcomes for rates in the current rate case are expected to inform and provide the foundation for proposed interim or bridge rate solutions. The Company is not providing its proposed interim solutions at this time but is mindful of the referenced statutory requirements represented in the questions posed and offers the following.

a. The Company's current rates, structures and metering and billing capabilities are anticipated to provide the foundation for proposed interim solutions. Given that current rates consist of optional residential and a combination of optional and mandatory commercial class time-varying rates that apply to certain components of rates, a proposal for moving to new, default rate structures will require consideration of impacts due to changes in rates and a transition plan to migrate customers to proposed new structures.

b. Current time-varying structures apply to the transmission and generation supply components of service. The Company anticipates that such current rate structures and any changes determined within the current Distribution rate case will provide the foundation for proposed interim rates. The Company will address proposed interim rate solutions that require changes to these components of service, and that may apply to Distribution rates, as part of its proposed interim rate submittal.

c. Current time-varying rates employ a 2-period, time-of-day (i.e., peak vs. off-peak) fixed rate structure that is expected to provide the basis for future time-varying structures for the proposed interim rate design. Such structures may be proposed on a seasonal basis for some components of service in the proposed interim rate design.

d. The Company expects consumer protections afforded by the Company's tariff (i.e., the terms and conditions for distribution service and for generation supply), "consideration for principles of gradualism and customer acceptance" in proposed rates, and further "established exceptions as deemed appropriate by the authority, including, but not limited to, for medically protected and financial hardship customers", pursuant to Conn. Gen. Stat. Sec. 16-243n, Section 20, part (b)(4), effective July 1, 2025, will be addressed as part of the Company's proposed interim rate design.

e. A marketing, education and outreach plan for residential and commercial customers will be developed to educate customers about any interim or bridge solutions proposed, as those options become available, to inform them of the benefits, necessary behavior modifications and the steps to enroll or unenroll as necessary.

f. Empirical support for the rate differential for peak and off-peak rates being addressed in the current Distribution rate case, including calculations and applications in proposed rate design and as informed by the marginal cost analysis performed as part of the current case, is expected to provide insight into the cost basis for setting a peak and off-peak differential for distribution and transmission rates anticipated to be to be developed and submitted as part of the October 1, 2027 filing. Consideration of differentials reflected in statutory or regulatory constraints and requirements are expected to be reflected in the Company's proposed generation supply rates portion of service in the proposed interim rate solution.

Date Filed: October 27, 2026

Witness: Jared A. Lawrence, Shamus O'Brien, Edward A. Davis and Kimberly R. Parsons
Request from: Department of Energy and Environmental Protection

Question:

(TVR Customer Engagement Plan) Refer to Exhibit CLP-RATES-8 Provide the proposed implementation schedule for the TVR Customer Engagement Plan.

Response:

The Company has not established a formal implementation schedule for the TVR Customer Engagement Plan. As discussed in Exhibit CLP-RATES-8, the most effective time to engage customers regarding TVR offerings is following full deployment of Advanced Metering Infrastructure ("AMI"), when customers will be able to fully realize the benefits of TVR rates. Customers will be best positioned to evaluate and respond to TVR opportunities after accumulating at least one year of their own interval usage data, which can help provide a meaningful understanding of their usage patterns and potential opportunities to shift consumption in response to TVR price signals. Accordingly, the Company expects to establish a formal implementation schedule for the TVR Customer Engagement Plan after the AMI deployment timeline has been finalized and the timing of implementing new TVR offerings is known.

Date Filed: October 27, 2026

Witness: Jared A. Lawrence, Shamus O'Brien, Edward A. Davis and Kimberly R. Parsons
Request from: Department of Energy and Environmental Protection

Question:

(TVR Customer Engagement Plan) Refer to Exhibit CLP-RATES-8, Section 5.4. Please describe the objective performance standards that are contemplated for the TVR Customer Engagement Plan, including any numerical targets or benchmarks for customer awareness, engagement, enrollment, complaints, and opt-outs. If numerical targets have not yet been established, identify when and through what process they will be proposed.

Response:

The Company has not established objective performance standards, numerical targets, or benchmark levels for customer awareness, engagement, enrollment, complaints, or opt-outs as part of the TVR Customer Engagement Plan described in Exhibit CLP-RATES-8. As discussed in Exhibit CLP-RATES-8, the Company's proposed Customer Engagement Plan is intended to provide a framework for customer education, outreach, and evaluation of customer engagement efforts. The Company intends to monitor customer feedback, inquiry trends, participation patterns, customer research results, awareness measures, engagement metrics, and enrollment metrics to assess the effectiveness of customer engagement activities.

As stated in Exhibit CLP-RATES-8, the most effective time to engage customers regarding the benefits of TVR options is following full deployment of Advanced Metering Infrastructure ("AMI"), when customers will be better positioned to realize the full benefits of TVR offerings and the Company will have access to interval usage data that will support evaluation of customer participation and bill impacts. Accordingly, the Company has not proposed specific numerical targets at this time. Any future performance standards, targets, or reporting requirements may be informed by experience gained through customer engagement activities, customer research results, AMI deployment, TVR program implementation, and any requirements established by PURA in this or future proceedings.

Date Filed: October 27, 2026

Witness: Jared A. Lawrence, Shamus O'Brien, Edward A. Davis and Kimberly R. Parsons
Request from: Department of Energy and Environmental Protection

Question:

(TVR Customer Engagement Plan) Refer to CLP-RATES-8. Please explain how the Company will evaluate whether customers understand the structure and potential bill impacts of TVR rates including, but not limited to:

a. the metrics, performance targets, and data sources the Company will use, including, at a minimum, customer survey results, enrollment and opt-out rates, customer inquiries and complaints, and actual bill impacts.
b. how these results will be separately assessed for financial-hardship, medically protected, low-income, limited-English-proficiency, and other customer groups requiring additional protections.
c. the frequency of evaluation, how results will be reported to PURA, and what corrective actions the Company will take if customers demonstrate low understanding or experience material adverse bill impacts.

Response:

a. The Company intends to evaluate customer understanding of Time-Varying Rates ("TVR") through a combination of customer research, customer feedback, and operational metrics. As described in CLP-RATES-8, the Company intends to monitor customer feedback, inquiry trends, participation patterns, customer research results, awareness measures, engagement metrics, and enrollment metrics to assess the effectiveness of its customer engagement efforts. Customer research may include surveys designed to measure customer awareness of TVR offerings, understanding of program design and potential bill impacts, familiarity with available TVR options, and recall of Company communications regarding TVR programs. Engagement metrics may include click-through rates, email open rates, event attendance, web views, and engagement with social media posts. Enrollment metrics may include the number of customers enrolled in a TVR rate, as well as enrollment and opt-out activity. The Company also intends to monitor customer inquiries and complaints received through both formal and informal channels. To the extent available, the Company may evaluate customer bill impacts and customer experiences to help assess the effectiveness of customer education and engagement efforts. As discussed in CLP-RATES-8, the most effective time to engage customers regarding the benefits of TVR options is following full deployment of Advanced Metering Infrastructure ("AMI"), when customers will be better positioned to realize the full

benefits of TVR offerings, framed for them using at least one year of their own interval usage data. Full implementation of AMI will also provide interval usage data that will enable the Company to better understand customer participation, including how customers may shift electricity usage in response to TVR price signals and the resulting impacts on customer bills.

b. The Company intends to utilize customer account attributes maintained in its systems, including financial hardship and medical protection designations, to analyze and segment customer research results where appropriate. Such analysis may help identify customer segments that could benefit from additional education, outreach, or tailored communications regarding TVR programs. Although the Company does not maintain comprehensive language-preference information for all customers, it intends to offer survey participation opportunities in both English and Spanish and will use available information to evaluate customer understanding across customer groups when feasible.

c. The frequency of evaluation will depend on the metric being assessed and the timing and cadence of customer education, outreach, and engagement activities. The Company intends to monitor customer feedback, inquiries, complaints, and other relevant customer engagement metrics on an ongoing basis, while customer research activities, such as surveys, may be conducted periodically. The Company proposes reporting to PURA on its TVR Customer Engagement Plan, including all required documentation as directed by PURA, annually on June 1 following the Order in Docket No. 26-05-10. However, the Company notes that this reporting cadence may be adjusted or superseded by reporting requirements PURA may establish for a future AMI-related TVR customer engagement plan as an outcome of future AMI-related proceedings. The results of these evaluations will be used to inform and refine customer education, outreach, and engagement activities related to TVR offerings. Should the Company identify opportunities to improve customer understanding of TVR programs, it may modify communications, educational materials, outreach strategies, or other customer engagement efforts as appropriate.

Date Filed: October 23, 2026

Witness: Jared A. Lawrence
Request from: Department of Energy and Environmental Protection

Question:

(Phased AMI Enabled TVR Availability) Provide a summary timeline, using calendar dates, for completion of the principal capabilities needed for AMI-enabled TVR, including AMI meter deployment, interval-data availability, the MDMS, the CIS billing capability, the customer portal, and the rate-comparison tool.

Response:

A specific timeline for execution of the AMI Plan is contingent upon the date of receipt of an order from PURA approving the AMI Implementation Plan, and whether the approved plan is reasonable, balanced and accompanied by a fair, reasonable and appropriate cost recovery framework. The following dates assume that PURA's approval of the AMI Implementation Plan will occur on July 1, 2027, and that the Plan is executable as issued, including the interrelated technology solutions. In particular, the timeline included in the AMI Implementation Plan assumes that the capabilities and integrations established for Massachusetts will be leveraged for Connecticut customers, rather than having to design and implement new ones, which would require an additional year or more to restart project development. Furthermore, the following target dates are subject to final determination of business and technical requirements specific to the Connecticut deployment, and may be influenced by other factors outside the Company's control:

- AMI meter deployment – first customers receive meters: January 31, 2030
- AMI meter deployment – substantially complete: January 31, 2033
- Interval data availability – first customers: January 31, 2030
- Interval data availability – substantially all customers: January 31, 2033
- MDMS: January 31, 2030
- CIS billing: January 31, 2030
- Customer portal: January 31, 2030

Rate comparison tool: The availability of the rate comparison tool will be contingent upon the approval of one or several TVR options that can be used to validate the design and testing of the Connecticut-specific instance of the tool. The Company expects to have the foundational capabilities available in relation to the modernized CIS, MDMS and customer portal, by virtue of its Massachusetts implementation. However, the Company will require intelligence specific to Connecticut on TVR design and opt-in/out policy (and potentially other factors based on future TVR discussions) before finalizing the tool's design. If PURA adopts the Company's

recommended approach of utilizing actual customer interval data gathered during the AMI deployment to inform TVR design so that broad TVR can be launched with a good customer experience one year after AMI meter installation completion, the rate comparison tool would be available for Connecticut customers no later than December 31, 2033.

Date Filed: October 26, 2026

Witness: Jared A. Lawrence
Request from: Department of Energy and Environmental Protection

Question:

(Phased AMI Enabled TVR Availability) Please explain whether the Company evaluated offering AMI-enabled TVR on a voluntary, pilot, or geographic basis to customers whose meters and supporting systems are operational before system-wide deployment is complete. Summarize the principal benefits, risks, and operational considerations identified and explain the basis for the Company's proposed timing.

Response:

With respect to TVR, the Company's proposed AMI Implementation Plan places emphasis on vital objective of deploying the full span of AMI's technical capabilities, while providing a positive customer experience. To achieve these important objectives, the AMI Implementation Plan ensures there is adequate customer usage data to inform in-depth stakeholder discussions on consensus TVR designs and policies. Customers typically want to maintain control and have options regarding future TVR. Therefore, it is important that customers have access to a robust set of their own AMI interval usage data and a reliable Rate Comparison Tool to make informed decisions about their TVR options.

Furthermore, the Company's AMI Implementation Plan avoids confusion about eligibility (based on whether a customer has received an AMI meter) that could cause frustration and increase the customer service burden during the AMI deployment. By planning to launch TVR broadly for all customers approximately one year after completion of AMI meter deployment, the Company is providing the foundation for thoughtful consensus-based TVR design and the data and tools for customers to make positive decisions.

In contrast, an accelerated TVR (partial) launch during AMI meter deployment, while technically feasible, assuming consensus can be reached on the pilot rates, would be a decision that would run the risk of sub-optimally designed rate components, inadequate access to data and tools for participating customers to assess and be confident in their options, and eligibility confusion that could cause frustration with TVR and the broader AMI deployment. Therefore, the Company's TVR timeline is designed to leverage the optimal path to higher customer satisfaction, higher sustained TVR adoption and, ultimately achievement of the highest benefits that TVR can offer.

Date Filed: October 23, 2026

Witness: Jared A. Lawrence
Request from: Department of Energy and Environmental Protection

Question:

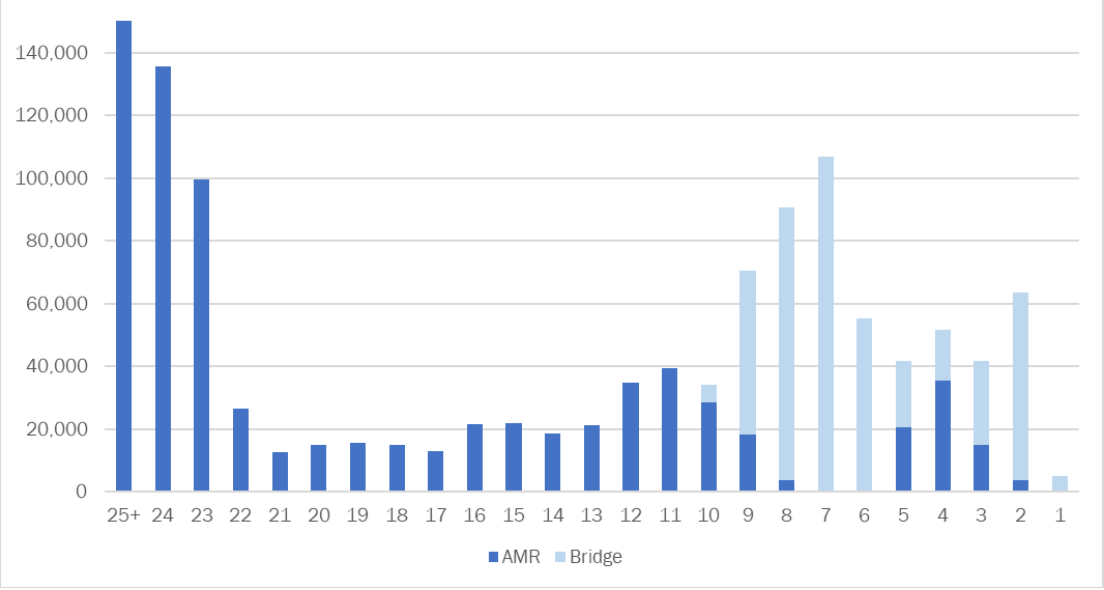
(AMI) Please provide the breakdown of total AMR meters currently nearing the end of their useful lives in Eversource's Connecticut territory and how many years are remaining in their useful lives?

Response:

Please refer to the petition filed on October 1, 2026 in Docket No. 17-12-03RE02, Exhibit CLP-AMI-3, at page 109, Figure 10 for the requested information.

The majority of the existing Eversource AMR and bridge meter population is nearing the end of its useful life. The Company transitioned from manual meter reading to its current AMR drive-by system in the early 2000s, installing over 600,000 meters between 2000 and 2003. As a result, as shown in Figure 10, by 2029, approximately 600,000 meters, nearly 50% of the Company's meter population, will be over their estimated useful life of 20-years.

Figure 10 – Electric Meter Age Profile



Date Filed: October 26, 2026

Witness: Jared A. Lawrence
Request from: Department of Energy and Environmental Protection

Question:

(AMI) Please provide the estimated cost differences between the existing letters of intent (LOIs) and pricing proposals if implementation proceeds prior to early 2027 versus if implementation proceeds as an outcome from this rate case according to its current time schedule?

Response:

The Company no longer expects that it can commence implementation "prior to early 2027," due to delays in regulatory resolutions. Please refer to BETP-053, Attachment 1 CONFIDENTIAL, for information on the letters of intent as it pertains to an outcome on AMI implementation coming at the end of this rate proceeding.

Date Filed: October 27, 2026

Witness: Jared A. Lawrence
Request from: Department of Energy and Environmental Protection

Question:

(AMI) Please provide a detailed breakdown of what subcomponents and their respective costs constitute the $432 million in back office system expenses necessary to begin AMI deployment.

Response:

The $432 million figure was reviewed within the AMI Stakeholder Review of the BCA Refresh in May 2026, please refer to BETP-054, Attachment 1, for a copy of the slide of the referenced figure. The $432 million in back-office system costs represents the rounded cumulative total of the projected six-year nominal capital and O&M costs for the Meter Data Management System ("MDMS"), Customer Information System ("CIS"), and Load Settlement. The cost estimates were developed using actual costs, ongoing costs, and indicative estimates, as applicable to each system.

Please refer to Table 1 below[1] for a cumulative total of all capital and O&M projected costs, and refer to Exhibit CLP-AMI-3, page 16.

Table 1

Back Office System	**6-Year Nominal Capital**	**6-Year Nominal O&M***	**Totals**
Meter Data Management System (MDMS)	$63,000,000	$21,000,000	$74,000,000
Customer Information System (CIS)	$212,500,00	$102,400,000	$314,900,000
Load Settlement	$28,800,000	$4,000,000	$32,800,000
Total	**$304,300,000**	**$127,400,000**	**$431,700,000**

[1] Note: these figures are rounded.

The following provides a high-level breakdown of the costs by back-office system and the basis for each estimate. For additional detail regarding the underlying cost components, assumptions, and calculation methodology, see Exhibit CLP-AMI-3, Section D.3 – Back-Office Systems.

- **MDMS – $63.0 million capital and $21.0 million O&M.** The estimate is based on actual upfront and ongoing Massachusetts AMI Program costs for implementing and maintaining MDMS, repurposed for Connecticut. These costs include application software, interfaces, procurement and contracting services, system implementation services, consulting services, internal labor, hardware, program management, data conversion, training, and ongoing service and maintenance fees. For a full breakdown of all costs, please refer to pages: 127–132.

- **CIS – $212.5 million capital and $102.4 million O&M.** The estimate is based on indicative Massachusetts CIS replacement and integration costs, modeled for Connecticut, including system integration, software and licensing, data conversion, implementation, and ongoing support. For a full breakdown of all costs, please refer to pages: 135–140.

- **Load Settlement – $28.8 million capital and $4.0 million O&M.** The estimate is based on indicative estimates informed by similar estimates performed for the Massachusetts AMI Program, including labor, hardware, software, procurement and contracting, system integration, data conversion, and ongoing maintenance and licensing. For a full breakdown of all costs, please refer to pages: 142–143.

Date Filed: October 23, 2026

Witness: Jared A. Lawrence
Request from: Department of Energy and Environmental Protection

Question:

(AMI) Please provide greater insight as to why all $432 million of back office system upgrade expenses must be frontloaded before AMI meters can start incrementally realizing benefits for CT?

Response:

The most significant change that comes about with the implementation of AMI is the magnitude of change relating to data collection, storage, security and analysis. These changes require a major change in backroom information systems. In that regard, the Company's current legacy CIS and MDMS have only very limited capabilities and would be unable to support most AMI benefits related to the collection, storage, processing and analysis of interval usage data and advanced customer notifications in their current forms.

Accordingly, if the Company attempted to deliver some capabilities via the legacy systems, substantial investments be required to essentially "retro-fit" the legacy systems, which would constitute "throw-away" work, as the systems would still need to be replaced during the AMI Implementation Plan in order to enable the full spectrum of AMI benefits (including TVR). Additionally, the AMI Plan includes the design and deployment of the AMI meters and network, which are linked to the back-office systems by a modernized head-end system that collects the meter data from the network access points.

For example, one of the components of the AMI Plan is the integration of the new head-end system with the new MDMS. The installation of meters before the new MDMS is deployed would require an additional "throw-away" investment to integrate the new head-end system with the legacy MDMS. Therefore, the Company's approach is to first modernize the back-office systems prior to AMI meter deployment in order to achieve the most cost-efficient outcome, obviating the need to generate "throw-away" expenses for integrations between new technologies and retiring technologies with limited capabilities.

Date Filed: October 27, 2026

Witness: Donald J. Scacco Jr., Digaunto Chatterjee and Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBR) Refer to CLP-PBR-1, p. 8 and 66) and CLP-ELP-1 pg. 115-116. In your testimony it states that the purpose of PBR implementation is to effectively "mimic the forces that would have been in play if there was competition" where firms "compete to provide the best service at the lowest cost through effective operations" (CLP-PBR-1, pg. 8). Please provide greater support for why the company feels these incentives/penalty levels will achieve the objective of PBR by mimicking competitive market forces to provide the best/lowest cost service.

Response:

The objective of performance-based regulation is to replicate the economic incentives that encourage firms in competitive markets to improve efficiency, control costs, and maintain high-quality service that their customers will want to purchase. CL&P's proposed Performance-Based Multi-Year Rate Plan ("PBMRP") seeks to achieve these objectives through an integrated framework of efficiency incentives, financial rewards and penalties for performance, and customer safeguards.

For example, the I–X revenue adjustment mechanism and cap on capital funding creates the same conditions that firms in a competitive industry face because they cannot themselves influence the price of their product and have to stay in line with industry trends. The PBMRP gives the Company a pre-set and externally indexed amount of budget to spend. That will discipline the Company in seeking out achievable efficiencies, as discussed on page 18 of CLP-PBR-1.

In addition, the Company has proposed a $10 million maximum penalty pool and $5 million maximum incentive pool for the performance incentives. These measures are intended to ensure quality of service and other performance objectives are top of mind for the Company, by virtue of the meaningful financial consequences that influence the Company's operational decisions. As discussed in CLP-ELP-1, the $10 million penalty pool represents approximately 0.5% of distribution revenues, and is tied to the exogenous cost threshold, which the Company considers financially significant without jeopardizing its financial stability. The smaller $5 million incentive pool is intended to encourage performance improvements while limiting additional costs to customers. This asymmetrical structure creates a stronger deterrent against service deterioration while also motivating improvements.

The allocation of the penalty structure reinforces the importance of reliability, with 70% ($3.5 million in potential penalties assigned to each of Blue-Sky SAIDI and SAIFI) and the rest (30% or $3 million) to customer service performance. The incentive pool also has greater amount allocated to reliability ($3 million), with remainder ($2 million) allocated to customer service improvements. Furthermore, the PIMs use a sliding-scale structure, which provides progressively greater financial consequences as performance deviates from established targets. This is discussed on page 116-117 of CLP-ELP-1.

Together with the overall revenue adjustment mechanism, and financial incentives and penalties seek to mimic competitive market pressures by rewarding operating efficiencies while deterring reliability or service quality degradation and encouraging improvements. The Company has proposed penalties and incentives at these levels in order to strike a reasonable balance between providing meaningful financial incentives, protecting customers, and maintaining financial stability so that the financial impact (positive or negative) does not have an out-sized impact on the Company's financial performance in either direction.

Date Filed: October 27, 2026

Witness: Douglas P. Horton
Request from: Department of Energy and Environmental Protection

Question:

(PBR) What are the estimated total potential impacts on net income profit margin or realized return on equity under the proposed 0.5% penalty threshold / 0.25% incentive threshold for total distribution revenues?

Response:

Based on the Company's proposed Rate Year distribution revenues of $1.92 billion, the maximum annual PIM penalty and incentive would be $9.61 million and $4.80 million, respectively. The testimony presents these amounts on a rounded basis as approximately $10 million and $5 million. (Exhibit CLP-REVREQ-2, Schedule C-1.0, line 19; Exhibit CLP-ELP-1, pp. 115–116.)

Applying the Company's filed gross revenue conversion factor of 1.3796, the estimated after-tax net-income impacts would be approximately negative $6.97 million and positive $3.48 million, respectively. (Exhibit CLP-REVREQ-2, Schedule A-2.0, line 27.) Based on the projected Rate Year rate base and proposed common-equity percentage of capitalization, these amounts would reduce realized ROE by approximately 19 basis points or increase realized ROE by approximately 9 basis points, respectively. (Exhibit CLP-REVREQ-2, Schedule A-1.0, line 16, and Schedule D-1.0; Exhibit CLP-ROE-1, p. 60.)

Date Filed: October 23, 2026

Witness: Julia Frayer
Request from: Department of Energy and Environmental Protection

Question:

(PBR) Refer to CLP-PBR-1, CLP-PBR-2 , pgs. 11-12, 38-39. Since the revenue cap is determined through the outputs of the I-X formula and has significant impacts on total revenue, to better understand how the inputs of this formula were calculated in LEI's TFP study, p lease provide the calculations and procedure used for the LEI study to calculate the number of customers served and electricity sales data (from form EIA-861 and FERC form 1 respectively) associated with figure 14 (CLP-PBR-2, pg. 38-39).

Response:

Please refer to LEI's TFP Workpapers (Exhibit CLP-PBR-2A) for the number of customers served data used in the Industry TFP Study. Also, please refer to BETP-058, Attachment 1, showing the total electricity sales data from 2005-2024 used in the sensitivity analysis and Figure 14 (CLP-PBR-2). Customer data was obtained from EIA Form 861, while electricity sales data were obtained from FERC Form 1. For Figure 14, LEI aggregated the reported data across the 88 electric distribution companies included in the Industry TFP Study to obtain annual industry totals. No additional calculations or adjustments were made to the underlying customer and electricity sales data, other than the aggregation necessary to present the industry totals.

Date Filed: October 23, 2026

Witness: Julia Frayer
Request from: Department of Energy and Environmental Protection

Question:

(PBR- negative X factor) Refer to CLP-PBR-1, CLP-PBR-2 pgs. 11-12, 38-39. Please provide details regarding any instance where an electric utility proposed a negative X-factor (productivity factor) value within a performance-based ratemaking or multi-year rate plan and whether the value was subsequently approved or rejected by the PUC in the state which it was proposed? For each identified instance please provide: (1) the specific negative X-factor value(s) approved or rejected; (2) the name of the state and the public utility commission that authorized or did not approve the value; (3) the specific docket number, formal filing name, and exact approval date associated with each instance; (4) a complete citation or copy of the order, including any textual justification provided by the commission for adopting or rejecting a negative productivity offset and the final approved X-factor value.

Response:

The important conceptual principle to note in relation to the negative X-factor is that it arises from the fact that electric and gas utilities are infrastructure intensive businesses, with obligations to serve, so that the growth in capital inputs outpaces the growth in outputs when measured as the number of customers or sales volumes. This causes the negative value for the X-factor. Thus, if the objective is to account for the growth in the cost of capital inputs in a PBR Plan, there are ratemaking alternatives, including overall capital tracking mechanisms. As a result, virtually every United States jurisdiction has some method in place to account for this dynamic. The negative X-factor is one such approach.

With a specific focus on the application of a negative X-factor in the context of a multi-year PBR Plan, information readily available to LEI provides examples in Massachusetts and New Hampshire, in which negative X-factors were initially proposed or calculated as part of a performance-based ratemaking ("PBR") or multi-year rate plan. Three such proceedings occurred in Massachusetts and New Hampshire. Of these proceedings, two resulted in the approval of a negative X-factor, although only one rate application involved a formally proposed negative X-factor that was subsequently approved.

1. Massachusetts – Eversource (D.P.U. 17-05): NSTAR Electric Company and Western Massachusetts Electric Company initially proposed an X-factor of −2.56%, subsequently revised to −2.64% following a correction to the total factor productivity study produced by Mark E. Meitzen, Ph.D., of Christensen Associates. In its November 30, 2017 Order, the

Massachusetts Department of Public Utilities ("DPU") approved an X-factor of −1.56%. The DPU found that the utilities' productivity study was conducted using reasonable data and assumptions but reduced the proposed negative X-factor by 1.08 percentage points to reflect the removal of the proposed $400 million grid modernization base commitment from the PBR mechanism. In that proceeding, the Company had initially proposed to undertake incremental Grid Modernization investments without a separate capital cost recovery mechanism. In the final order, the Department opted to enact a targeted grid modernization capital cost recovery mechanism, rather than establishing funding as part of the PBMRP. This allowed for the reduction to the negative X factor as compared to amounts originally proposed by the Company. D.P.U. 17-05, Order Establishing Eversource's Revenue Requirement, November 30, 2017, pp. 337, 391–392.

2. Massachusetts – Eversource (D.P.U. 22-22): NSTAR Electric Company initially proposed an X-factor of −1.45%, based on the results of Mark E. Meitzen's and Nicholas A. Crowley's total factor productivity study. However, NSTAR Electric Company subsequently revised its proposal to zero X-factor during the proceeding, consistent with the Attorney General's recommendation. In its November 30, 2022 Order, the DPU approved an X-factor of zero, finding the revised proposal appropriate in light of other modifications to the PBR plan. D.P.U. 22-22, Final Order, November 30, 2022, pp. 17, 56–57.

3. New Hampshire – Eversource (DE 24-070): Public Service Company of New Hampshire's application included an independently produced total factor productivity study that produced an X-factor of −1.42%. The utility formally proposed an X-factor of zero. In Order No. 28,170, issued July 25, 2025, the New Hampshire Public Utilities Commission approved the study-derived X-factor of −1.42%, as the negative X factor in that case reasonably aligned with the capital plan for PSNH. In consideration of the negative X-factor, the Commission eliminated the utility's proposed K-bar capital recovery mechanism and adopted the negative productivity factor to provide sufficient revenue under its alternative regulation framework. DE 24-070, Order No. 28,170, July 25, 2025, pp. 12–13, 50–51.

These proceedings demonstrate that negative productivity offsets have been considered and, in certain circumstances, approved for electric distribution utilities. The final determination has depended on the underlying productivity evidence and the design of the broader PBR framework, including the treatment of capital expenditures and other revenue recovery mechanisms.

Date Filed: October 23, 2026

Witness: Julia Frayer
Request from: Department of Energy and Environmental Protection

Question:

(PBR- Z factor) Refer to Exhibit CLP-PBR-1p. 74. Provide a summary of Z Factor designs tested and implemented in other jurisdictions, including the decision where such designs were approved, the qualifying criteria for associated expenses and the associated tariffs

Response:

The following table summarizes the Z-Factor provisions approved in a sampling of jurisdictions that have deployed an I-X based PBR framework. Approval of these mechanisms does not necessarily constitute approval of specific cost adjustments that are generally evaluated on a case-by-case basis.

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference
New Hampshire – Public Service Company of New Hampshire	Approved a relatively narrow Z-Factor covering specific cost changes resulting from state or federal government actions, regulatory cost reassignments, and changes in accounting rules. These adjustments may be forward-looking when known and measurable.	Cost changes must fall within the Commission's defined categories and satisfy the applicable threshold. The Commission adopted its earlier definition for the exogenous-event provision.	$1.5 million revenue-requirement impact	New Hampshire Public Utilities Commission Order No. 28,170 (July 25, 2025), Docket DE 24-070, pp. 2 and 54.
Alberta –	Approved a general Z-Factor for	All five criteria must be met: (1) outside	Dollar equivalent of an after-tax 40-	AUC Decision 27388-D01-2023

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference
Electric and Gas Distribution Utilities	significant positive or negative financial impacts from exogenous events. May apply to capital or O&M. No exclusive list of qualifying events is prescribed.	management's control; (2) material impact; (3) no significant influence on the inflation factor; (4) prudently incurred costs; and (5) unforeseen event. The impact must also lack another reasonable recovery mechanism within the PBR framework.	basis-point change in ROE, calculated using the utility's equity supporting 2023 going-in rates; escalated annually by I-X	(October 4, 2023), Appendix 5, pp. 119–120.
Massachusetts – Eversource (NSTAR Electric)	Approved exogenous costs from: (1) tax-law changes uniquely affecting the industry; (2) industry-specific accounting changes; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.	Cost change must be beyond company control, arise from qualifying legal/accounting/regulatory action, uniquely affect electric distribution rather than the general economy, and not be reflected in GDP-PI. Supporting evidence is required, and eligibility is determined case by case.	$4 million per individual event in the first PBR year, adjusted annually by GDP-PI Generally noncumulative, with limited exceptions for related property-tax events	MDPU, NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 22-22, Final Order, (November 30, 2022), pp. 71–76.
Massachusetts – Fitchburg Gas and Electric Light Company (Unitil Electric)	Approved the standard MA categories of industry-specific tax, accounting, regulatory, judicial, and legislative changes.	Beyond management control; arises from qualifying changes in requirements or directives; unique to the distribution industry; material; and not reflected in the inflation index or otherwise in PBR formula.	$110,000 per event with annual GDP-PI adjustments	MDPU, Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 23-80/D.P.U. 23-81, Final Order (June 28, 2024), 51–54

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference
Massachusetts – Massachusetts Electric Company and Nantucket Electric Company (National Grid Electric)	Approved the standard Massachusetts categories. Also expressly approved potential Z-Factor recovery for certain major storm-related O&M expenses, subject to additional conditions and prudence review.	Qualifying costs must be beyond control, arise from industry-specific legal/accounting/regulatory changes, not be reflected in the applicable inflation adjustment, and meet the significance threshold. For major storms, additional storm-fund eligibility requirements apply.	$3.6 million per individual event initially, adjusted annually by GDP-PI Special storm provision: individual storm O&M expenses above $30 million, where the storm fund balance plus costs exceeding $30M, exceeds $75M.	MDPU, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 23-150, Final Order (September 30, 2024), pp. 94–96.
Ontario – Electricity Distributors	Approved a general Z-Factor mechanism for extraordinary, unforeseen events outside management's control. Examples include severe storms and other exceptional events. The framework does not restrict claims solely to legal or regulatory changes.	Three principal tests: (i) causation, (ii) materiality, and (iii) prudence. Costs must be incremental to those reflected in rates; management must show the event could not reasonably have been planned or budgeted for. Current guidance also requires the distributor's achieved ROE not to exceed its deemed ROE by more than 300 basis points.	Under the OEB's 3rd Generation IRM, the standard Z-factor materiality thresholds are C$50,000 for utilities with distribution revenue requirements up to C$10M; 0.5% of distribution revenue requirement for utilities above C$10M through C$200M; C$1M for utilities above C$200M. The threshold applies on a per-event basis.	Ontario Energy Board, Supplemental Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, Docket EB-2007-0673, (September 17, 2008), Appendix B, VII-VIII

Jurisdiction / Regulatory decision	Approved Z-Factor scope and qualifying events	Criteria for Z-Factor eligibility	Materiality threshold	Reference
			However, utilities operating under OEB-approved Custom IR plans may be subject to different, utility-specific materiality thresholds.	
Hawaii – Hawaiian Electric Companies	Approved a broad Z-Factor mechanism for exceptional events beyond reasonable utility management control. Potential examples discussed in the proceeding include tax-law changes, natural disasters, and pandemics, but the Commission deliberately did not establish an exclusive or automatically approved list. Changes to ROE or credit ratings do not qualify.	Six criteria: (1) outside control of a prudent utility; (2) directly related to the exogenous event; (3) impact outside the original rate base; (4) prudently incurred; (5) not otherwise recovered through rates, insurance, government aid, or third parties; and (6) above materiality threshold. Each request is evaluated individually.	$4 million per event for HECO; $1 million per event for HELCO and MECO	Hawaii Public Utilities Commission, Decision and Order No. 37507 (December 22, 2020), Docket 2018-0088, pp. 57–60 and 80.

Date Filed: November 03, 2026

Witness: Douglas P. Horton and Julia Frayer
Request from: Department of Energy and Environmental Protection

Question:

(PBR- K-bar) Refer to Exhibit CLP-PBR-1 p. 69. Describe what a "K-bar arrangement" is and provide more detail of K-bar arrangements approved in Massachusetts and Alberta. Compare and contrast this type of capital funding mechanism with the Company's proposal.

Response:

A K-bar mechanism is a formula-based capital funding mechanism used within a performance-based regulation ("PBR") plan as described in Exhibit CLP-PBR-1. The K-bar is designed to provide additional revenue to the utility to support capital investment, where the base PBR-indexing mechanism is insufficient to support the required level of support using only the selected I-factor and X-factor. A K-bar typically establishes a level of capital funding support using a notional amount pursuant to a benchmark (in some cases historical plant additions), relative to the revenue generated by the PBR formula and selected I-factor and X-factor.

For the 2024–2028 PBR term, the Alberta Utilities Commission ("AUC") approved K-bar funding mechanism based on the five-year average of 2018–2022 actual plant additions. The AUC explained that K-bar "is not intended to provide funding for projects on a line-by-line basis," but rather supplements the basic I-X mechanism by providing "an envelope of funding for the management of business-as-usual activities with a reasonable opportunity to earn the approved rate of return." See AUC Decision 27388-D01-2023, *2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities*, October 4, 2023.

As discussed in the final decision of the Massachusetts Department of Public Utilities in D.P.U. 22-22, the K-bar approach, originally developed by the Alberta Utilities Commission ("AUC"), is one under which "the I-X PBR formula escalates historical average capital additions not subject to recovery through capital trackers to form the basis of future approved capital recovery."[1] Supplemental recovery is determined by the difference between the utility's escalated historical capital needs and the capital-related revenue already provided through the I-X formula. For NSTAR Electric, under the MDPU-approved five-year PBR plan (2023–2027), the K-bar mechanism provides incremental capital revenue support based on a rolling average of historical plant additions. The initial K-bar adjustment, effective January 1, 2024, uses the average of actual

[1] Massachusetts Department of Public Utilities, NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 22-22, November 30, 2022, at 20.

plant additions placed in service from 2018–2022, with the historical averaging period updated annually thereafter. The mechanism determines annual capital revenue support using the approved rate base associated with capital additions, subject to an annual constraint. Specifically, the MDPU implemented an annual capital spending constraint of up to ten percent from the annual capital spending forecasted in the rate case proceeding. The MDPU recognized the challenges in accurately forecasting capital spending, as well as the potential impacts on future capital spending from recent and anticipated changes in energy and climate policy in the region. Accordingly, the MDPU found it appropriate to allow a modest amount of flexibility from the Company's forecasted budget in setting the expenditure restraint.[2]

CL&P is proposing a capital support mechanism with certain difference, more closely correlated with the direction of PBR policy in Connecticut. The Company's proposed mechanism is referred to as the "F" factor and is based on a fixed annual capital investment level established from the Company's capital forecast presented in this proceeding. Actual plant additions placed in service would be reconciled against the forecasted in this proceeding through PURA's annual RAM proceedings, and the allowed rate base and associated revenue requirement would be limited to the lesser of the revenue requirement for the approved forecast or the revenue requirement for actual plant in service. Capital spending above the approved forecast would not be recoverable during the initial four-year PBMRP term. See Exhibit CLP-ELP-1, at 101-102.

The key difference between the MDPU K-bar and the Company's proposed F Factor is that K-bar determines supplemental capital funding formulaically from a historical capital-additions benchmark, whereas CL&P's F factor begins with a PURA-approved capital forecast and reconciles recovery to actual plant placed in service, subject to the approved forecast cap with such reconciliation available only on a downward basis, as appropriate.

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2 Id. at 61-62.

Date Filed: November 03, 2026

Witness: Julia Frayer
Request from: Department of Energy and Environmental Protection

Question:

(PBR) Refer to Exhibit CLP-PBR-1 p. 69. Compare and contrast the British Columbia example of a PBR framework to: a) the Company's proposal; and, b) a conventional multi-year rate plan.

Response:

a) Both the FortisBC framework and CL&P's proposed performance-based multi-year rate plan ("PBMRP") are examples of MRPs that incorporate elements of performance-based regulation. Although both frameworks apply formula-based adjustments to OM&A expenses and provide separate treatment for capital expenditures, the frameworks differ in certain design features, including the structure of the capital recovery mechanism, earnings sharing mechanism, and certain other features.

The table below compares the key features of FortisBC's approved PBR framework with CL&P's proposed framework. The comparison illustrates how different MRP structures may be designed to achieve similar regulatory objectives while reflecting jurisdiction-specific circumstances.

Feature	FortisBC Inc. (FBC) – British Columbia (Order No. G-70-25)	Connecticut Light and Power Company d/b/a Eversource Energy's (Docket No. 26-05-10) proposal
Overall structure	Indexed -based approach: Formula-based treatment applies to controllable O&M, while capital and certain other costs are treated separately.	The proposed Performance-Based Multi-Year Rate Plan (PBMRP) follows the methodology of a traditional, comprehensive PBR plan, except that the formula-based revenue adjustment applies only to OM&A costs, while capital costs are addressed separately through a capital support mechanism.

Term	2025-2027	2027-2031
O&M	Formula-based. Controllable O&M is escalated using an index-based formula incorporating inflation, productivity and customer growth. Certain costs remain outside the formula and receive forecast or flow-through treatment.	Formula-based. OM&A is adjusted annually using an inflation/productivity-based revenue-cap formula, together with a Consumer Dividend.
Capital funding	Forecast separately from the O&M formula. Growth, Sustainment and Other capital are established through approved capital forecasts and incorporated into rates. Capital forecast variances are subject to earnings sharing.	A capital support mechanism is used, which is estimated separately from the index formula that determines the approved OM&A amounts. A fixed annual capital level is established from the forecast presented in this proceeding and recovered through the F-factor. Actual plant placed in service is reconciled annually against the forecast, with recovery limited to the lower of the capital forecast presented in this proceeding or the actual plant additions in the given time period.
Efficiency incentive	The O&M formula creates an incentive to control costs because the utility's allowed O&M is determined formulaically rather than directly from its actual O&M spending.	The OM&A formula creates an efficiency incentive, supplemented by the Consumer Dividend. For capital, the forecast cap places the risk of spending above the approved amount on CL&P and therefore also provides an efficiency incentive.
Earnings sharing mechanism	Symmetrical earnings sharing. Variances from allowed earnings	Upside earnings sharing. Earnings above the authorized

	are shared between customers and the utility.	return are shared with customers; CL&P bears the downside risk.
Exogenous / uncontrollable costs	Qualifying costs outside the utility's control may receive exogenous-factor, flow-through, forecast, or deferral treatment rather than being forced into the O&M formula.	Qualifying events outside CL&P's control may be recovered or credited through a separate Z-factor.
Performance / service quality	Service-quality indicators operate alongside the rate framework to monitor utility performance.	Performance metrics and incentive mechanisms operate alongside the PBMRP to link specified outcomes to rewards or penalties.
Annual review	Annual reviews continue during the framework to implement rates and review relevant forecasts, actual results and framework components.	Annual compliance filings are used to implement the PBR adjustment and review earnings sharing, capital reconciliation, performance results and other adjustments.

b) MRPs can take various forms, including forecast-based, index-based and hybrid approaches, depending on the regulatory objectives and circumstances of the jurisdiction. There is no single, universally prescribed structure that constitutes a "conventional MRP." Accordingly, the Company is unsure of what this question may be asking when asking for a comparison with a generic "conventional MRP".