Date Filed: September 21, 2026

Witness: Douglas P. Horton and Julia Frayer
Request from: Office of Consumer Counsel

Question:

(Customer dividend) In Exhibit CLP-PBR-1, LEI states that approved Consumer Dividends or stretch factors in other North American jurisdictions generally range from 0.15% to 0.60%, as reflected in Figure 12 of Exhibit CLP-PBR-3:

a. Please provide a list of each utility and jurisdiction included in deriving this range, including the applicable PBR plan or regulatory proceeding, the approved Consumer Dividend/stretch factor, and the year(s) in which it applied.
b. Please explain the criteria used to select the utilities and PBR plans included in this comparison, including whether the comparison includes all relevant North American PBR plans reviewed by LEI or a subset.
c. Please explain how the 0.15%–0.60% range, and CL&P's position within that range, informed the selection of the proposed 0.30% Consumer Dividend, including any quantitative or qualitative analysis used to determine that 0.30% was appropriate for CL&P.

Response:

a. Figure 16 (not Figure 12) in CLP-PBR-3, which we are also including below, provides the jurisdictions, utilities, approved Consumer Dividends/stretch factors, applicable terms, and regulatory sources considered by LEI. The comparison includes, among others, Alberta's 2024–2028 PBR3 plan; FortisBC's 2025–2027 Rate Setting Framework; Massachusetts PBR plans for Massachusetts Electric/Nantucket Electric, NSTAR Electric, and Fitchburg Gas and Electric; New Hampshire's 2026–2029 alternative regulation plan for Public Service Company of New Hampshire; and the Ontario Energy Board's stretch-factor framework for Ontario electricity distributors.

Jurisdiction and EDC	Approved S Factor / Consumer Dividend	Term	Source
Alberta (ATCO Electric Ltd.; FortisAlberta Inc.; ENMAX Power Corp.; EPCOR Distribution & Transmission Inc.; ATCO Gas and Pipelines Ltd.; and Apex Utilities Inc.)	0.1% = Industry TFP + stretch factor 0.30% = "benefit-sharing premium" (X Factor premium)	2024-2028	Alberta Utilities Commission, *2024–2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities*, Decision 27388-D01-2023, Proceeding 27388 (October 4, 2023)
British Columbia — FortisBC Inc.	0.25% Stretch Factor	2025-2027	British Columbia Utilities Commission, *FortisBC Energy Inc. and FortisBC Inc. 2025 to 2027 Rate Setting Framework*, Orders G-69-25 and G-70-25 (March 18, 2025)
Massachusetts — Massachusetts Electric Company and Nantucket Electric Company	0.40% Consumer Dividend (applicable only when inflation is at least 2%; 0.20% when inflation is between 1% and 2%; and 0% when inflation is 1% or lower.	2020-2024	Massachusetts Department of Public Utilities, *Petition of Massachusetts Electric Company and Nantucket Electric Company for Approval of General Increases in Base Distribution Rates for Electric Service*, D.P.U. 18-150 (September 30, 2019)
Massachusetts — NSTAR Electric Company	0.25% Consumer Dividend (applicable only when inflation exceeds 2%)	2023-2027	Massachusetts Department of Public Utilities, *Petition of NSTAR Electric Company for Approval of a General Increase in Base Distribution Rates and a Performance Based Ratemaking Plan*, D.P.U. 22-22 (November 30, 2022)
Massachusetts — Fitchburg Gas and Electric Light Company	0.25% Consumer Dividend (applicable only when inflation exceeds 2%)	2024-2029	Massachusetts Department of Public Utilities, *Petitions of Fitchburg Gas and Electric Light Company for Approval of General Increases in Base Distribution Rates and Performance-Based Ratemaking Plans*, D.P.U. 23-80 and D.P.U. 23-81 (June 28, 2024)
Massachusetts — Massachusetts Electric Company and Nantucket Electric Company	0.40% (applicable only when the composite inflation index exceeds 2%)	2024-2029	Massachusetts Department of Public Utilities, *Petition of Massachusetts Electric Company and Nantucket Electric Company for Approval of a General Increase in Base Distribution Rates, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism*, D.P.U. 23-150 (September 30, 2024)
New Hampshire — Public Service Company of New Hampshire d/b/a Eversource Energy	0.15% (applicable only when GDP-PI inflation exceeds 2%)	2026-2029	New Hampshire Public Utilities Commission, *Public Service Company of New Hampshire d/b/a Eversource Energy – Request for Change in Distribution Rates: Order Establishing Permanent Rates and Alternative Regulation Through July 31, 2029*, Order No. 28,170, Docket DE 24-070 (July 25, 2025)
Ontario - All utilities	Based on benchmarking performance and ranges between 0.00% and 0.60%		Ontario Energy Board. *2025 PEG Benchmarking Report to the Ontario Energy Board*. Prepared by Pacific Economics Group LLC. August 18, 2025

b. Figure 16 was intended to provide an illustrative sample, rather than an exhaustive survey, of relatively recent North American PBR frameworks employing a formulaic revenue or rate-adjustment mechanism and an explicit Consumer Dividend, stretch factor, or comparable benefit-sharing component. LEI selected these examples to provide regulatory context for the magnitude of CL&P's proposed Consumer Dividend and to illustrate how

such factors have been incorporated into PBR frameworks in other North American jurisdictions. The comparison was not intended to include every North American PBR plan reviewed by LEI or to establish the minimum and maximum Consumer Dividend. Indeed, some jurisdictions have approved PBR frameworks without an explicit Consumer Dividend, stretch factor, or comparable benefit-sharing component, further demonstrating that the range shown in Figure 16 should not be interpreted as establishing regulatory minimum or maximum values.

c. LEI did not mathematically derive the proposed 0.30% Consumer Dividend from the 0.15%–0.60% range, nor was 0.30% selected specifically because it reflects the midpoint of that range. Rather, CL&P's modest above-benchmark OM&A costs historically indicated potential for additional efficiency improvements in the future and supported a positive, moderate Consumer Dividend. It is important to keep in mind that the benchmarking results on their own do not establish the annual rate at which those improvements can reasonably be achieved. The Company has therefore proposed an incentive-rich mechanism by which the 0.3% Consumer Dividend is just a starting point, and if efficiency improvements are achieved then the Consumer Dividend would grow over time to ensure that customers are immediately sharing in the financial benefits of achieved cost efficiencies.

LEI considered the regulatory precedents in Figure 16 as a reasonableness check on the magnitude of the proposed starting value for the Consumer Dividend. CL&P's 0.30% falls within the observed range, and between the 0.25% FortisBC stretch factor and the 0.40% Massachusetts Electric/Nantucket Electric Consumer Dividend in the more directly comparable OM&A-focused frameworks. LEI therefore concluded that 0.30% was reasonable in light of CL&P's benchmarking results and relevant regulatory precedent. Please also refer to the responses to OCC-443[i] and OCC-539[ii].

Prior Referenced Responses:

[i] OCC-443 Question:

Exhibit CLP-PBR-1 PBR Testimony Please explain quantitatively how LEI's benchmarking results support a 0.30% Consumer Dividend. Please explain how the Company's proposed 0.30% Consumer Dividend was derived from or otherwise informed by:

a. The Company's 22.9% average OM&A cost gap under the unit cost benchmarking analysis;
b. The Company's 11.9% average OM&A cost gap under the 2015–2024 econometric benchmarking analysis; and
c. The Company's 16.4% average OM&A cost gap under the 2021–2024 econometric benchmarking analysis.

d. Please provide any calculations, assumptions, analyses, or methodologies used to translate the identified efficiency gap into an annual achievable improvement.
e. Please explain why the widening gap does not support a Consumer Dividend greater than 0.30%, and provide all analyses relied upon in reaching that conclusion.

OCC-443 Response:

LEI did not derive the proposed 0.30% Consumer Dividend by applying a mathematical formula to any of the benchmarking gaps identified in parts (a) through (c). LEI's quantitative analysis was focused on the benchmarking itself. As explained in Exhibit CLP-PBR-3, LEI performed a unit cost analysis followed by an econometric analysis of the Company and the other 88 peers nationally. The benchmarking results measure CL&P's relative cost position compared with the average of all utilities (for the unit cost benchmarking) or a model-predicted benchmark for the Company's costs (for the econometrics benchmarking). A benchmarking study will report out relative efficiency, but it cannot measure the amount of cost reduction that can reasonably and sustainably be achieved in any particular year of the PBMRP, as explained in Exhibit CLP-PBR 1. Therefore, LEI examined what other jurisdictions have approved for stretch factor/consumer dividend, especially when the target utility is an average performer like CL&P. Please see Section 5 of Exhibit CLP-PBR-3.

The 22.9% result represents the average amount by which CL&P's OM&A cost per customer exceeded that of the national industry average under the unit cost benchmarking analysis. As LEI explains in Section 1.1 of Exhibit CLP-PBR-3, the unit cost analysis is an initial step in benchmarking analysis. Unit cost benchmarking does not control for differences in operating conditions and important business factors among utilities that will impact costs, such as the scale of business, the network composition, local costs of labor, etc. For that reason, the unit cost benchmarking results are not directly informative of a stretch factor for a utility, especially if the data allows for more rigorous econometric analysis.

The 11.9% result provides a more refined measure of CL&P's relative OM&A cost performance. Indeed, the econometric analysis takes account of such factors such as input prices, scale, and network characteristics. As the 11.9% remains a measure of the level of CL&P's costs relative to the model-predicted benchmark over the historical period (2015 2024), it does not provide guidance on future efficiency gains and must be interpreted cautiously. In addition, LEI considered the broader peer distribution in looking at the OM&A benchmarking results. CL&P ranked 54th out of 88 utilities based on its average result over the 10-year period, placing it within the broad middle of the group. Accordingly, its above benchmark OM&A costs represent an area for potential improvement, but are not an unusually large or extreme result relative to its peers. Those observations support a positive but modest Consumer Dividend, which based on LEI's collation of data from other jurisdictions, would be 0.30% as discussed in Section 5 of Exhibit CLP-PBR-3.

The 16.4% result comes from the econometric analysis of CL&P's OM&A costs against model-predicted benchmark, but for a much shorter period (2021-2024). Importantly, the recent-period results continue to show favorable overall cost performance: capital costs averaged 16.5% below benchmark (see Figure 15 in Exhibit CLP-PBR-3) and total costs averaged 3.1% below benchmark. As discussed in the Company's testimony, recent O&M cost pressures may include labor and vegetation management, as well as storm-related expenditures. Nevertheless, these provide context for the more recent period but do not establish the extent to which any individual cost category contributed to the 16.4% econometric benchmarking result or whether the same conditions will persist during the PBMRP term. Thus, the 16.4% OM&A result implies that additional operating-efficiency opportunities may exist, but does not give us any direct indication for how to size the Consumer Dividend.

LEI did not perform a calculation that converts the 22.9%, 11.9%, or 16.4% benchmarking differences into an annual achievable productivity improvement, and therefore there are no such calculations to provide. Such a calculation

would not be methodologically appropriate because the benchmarking analysis looks at various measures of productivity at a given point of time, and does not say anything about the prospective rate at which cost differences can reasonably and sustainably be eliminated over the next few years. LEI used the benchmarking results as empirical evidence of relative efficiency and confirmation that there is some room for improvement. LEI then considered regulatory precedent for Consumer Dividends and stretch factors, which suggested that regulators have used values ranging from 0.15% to 0.60% for other EDCs, with lower values for those that are more efficient and higher values for those that are very inefficient. LEI then finds the value of 0.30% as a reasonable starting point for the Company's proposed Consumer Dividend.

Two further points place the proposed 0.30 percent in context. First, as shown in Figure 16 of Exhibit CLP-PBR-3, the Consumer Dividends and stretch factors approved in other jurisdictions range from 0.15 percent to 0.60 percent. The Massachusetts consumer dividends in Figure 16 are also conditional on inflation: those mechanisms pay 0.25 to 0.40 percent only when inflation exceeds two percent, reduced amounts at lower inflation, and nothing in low inflation years. The Company's proposed 0.30 percent applies in all inflation conditions, so the guaranteed minimum benefit to customers is at or above the effective minimum of every mechanism in the comparison.

Second, the comparison is most direct when each mechanism is measured against the base to which it applies. The Company's S-Factor applies to the Core Operating Expense revenue requirement only, because capital is recovered through the separate Capital Funding Mechanism (Exhibit CLP-IAP-1 at 73). The most directly similar plans — an apples-to-apples comparison — are those in which regulators approved an OM&A-only revenue cap: National Grid in Massachusetts, with a 0.40 percent consumer dividend payable only when inflation is at least two percent, and FortisBC in British Columbia, with a 0.25 percent stretch factor (Exhibit CLP-PBR-1 at 47; Exhibit CLP-PBR-3, Figure 16).

Finally, the proposed design bounds its own ceiling. Because the S-Factor begins the first rate year at 0.30 percent and each year's result adjusts the level applied in the following rate year, the level can adjust no more than three times over the four-year term, and the highest level the mechanism can reach is 0.60 percent.

The illustrative calculation of how the Consumer Dividend operates over the PBMRP term is provided in OCC-432, Attachment 1.

[e] Q: *Please explain why the widening gap does not support a Consumer Dividend greater than 0.30%, and provide all analyses relied upon in reaching that conclusion.*

As discussed above in a – d, a benchmarking difference represents a measure of relative cost performance and should not be translated directly into an annual Consumer Dividend. Finally, 0.30% is the floor, not the ceiling, under CL&P's proposed mechanism. As explained in Exhibit CLP-PBR-1 at page 64, the Consumer Dividend can increase during the PBMRP term if the Company outperforms the applicable controllable O&M benchmark. Thus, the proposed design provides customers with additional benefits if CL&P achieves greater operating efficiencies than assumed in establishing the initial Consumer Dividend.

The Consumer Dividend is an affordability mechanism. As such, it must be evaluated for both providing a benefit to customers, as well as for sustainability. A dividend set too low forgoes customer benefit, while a dividend set beyond sustainably achievable efficiency would function as a rate reduction unsupported by actual cost performance. The proposed design addresses the scale question through movement rather than starting magnitude. The level begins at 0.30 percent, can never fall below that level or become a surcharge (Exhibit CLP PBR-1 at 64), rises automatically as the Company demonstrates efficiency, and is applied against the Company's O&M revenue requirement under the PBMRP. Unlike an earning sharing mechanism, which provides customer benefits only when earnings exceed the allowed return on equity, this mechanism will share the costs the Company controls, even when under its allowed rate

of return. The consumer dividend design provides customers with efficiency gains during the plan term without waiting for the next rate case, and at the next rate case all achieved efficiencies are reflected in rebased rates in full.

[ii] OCC-539 Question:

Performance Based Ratemaking Panel Exhibit CLP-PBR-1
Please explain the relationship, under the Company's proposed framework, between a utility's relative cost efficiency and the appropriate level of the Consumer Dividend.

a. Specifically, all else equal, would a utility whose OM&A costs are materially above its peer benchmark warrant a higher, lower, or unchanged Consumer Dividend relative to a utility whose OM&A costs are below its benchmark?
b. Please explain the economic rationale for the Company's answer and how that rationale was applied to the Company's proposal.

OCC-539 Response:

a. All else equal, a utility whose OM&A costs are materially above the benchmark would generally warrant a higher Consumer Dividend than a utility whose costs are below benchmark, because the former has greater potential for catch-up efficiency improvements. As explained in Section 2 of Exhibit CLP-PBR-3 and illustrated in Figure 4, a relatively less efficient utility may have greater opportunities to "catch up" to the industry's efficiency trajectory by adopting technologies or practices already implemented by more efficient peers. The Consumer Dividend reflects the potential for such improvements beyond the industry productivity trend.

   However, the "benchmark gap" or the percentage difference between CL&P's actual costs and the applicable benchmark cost, does not mechanically determine the annual Consumer Dividend. As explained in Section 5 of Exhibit CLP-PBR-3, benchmarking identifies relative cost performance and potential opportunities for improvement; it does not establish the annual rate at which those improvements can reasonably be achieved or that the entire gap can be eliminated within a single PBR term.

   For CL&P, the above-benchmark OM&A results support a modest Consumer Dividend in its OM&A-only revenue adjustment mechanism, as discussed in Exhibit CLP-PBR-3. In determining the appropriate magnitude, LEI also considered CL&P's favorable overall cost performance and relevant regulatory precedents. Please refer also to the Company's responses to OCC-431[i] and OCC-443[ii].

b. The economic rationale for this response is that benchmarking identifies relative cost performance and potential opportunities for improvement, but the actual Consumer Dividend earned is based on measured results. The Company applied this rationale in two steps, because the proposed Consumer Dividend is not a fixed number. The Company's relative cost position determined where the dividend starts, as described in part (a) and in the Company's responses to OCC-431 and OCC-443. The Company's actual performance as part of a performance-based rate determines whether it increases or stays at the floor.

   The dividend begins at 0.30 percent and moves each year based on measured results: up 0.10 percentage points in a year when the Company's Core Operating Expense per customer is below the inflation-adjusted benchmark, down 0.05 percentage points when it is not, and never below the 0.30 percent floor. The steps are deliberately asymmetric in customers' favor: the dividend rises twice as fast on demonstrated efficiency as it declines otherwise, and it can never fall below its starting level. The level customers receive therefore reflects how the Company actually performs, not a one-time judgment made before the period begins. An

illustration of the mechanism's operation is provided in the Company's response to OCC-423[iii], and a historical illustration in the Company's response to OCC-432[iv].

The efficiency incentive in the Revenue Cap Formula is the I minus X structure, combined with the power of the stay-out requirement. The Consumer Dividend supplements that structure and is deliberately sized small enough to preserve the incentive that produces the gains to be shared. The design shares efficiency -- as it is demonstrated -- rather than assuming it in advance. If the Company outperforms the benchmark, the dividend rises automatically during the term, up to the top of the approved range; if it does not, customers keep the guaranteed minimum every year. Because the rate at which efficiency gains can be sustainably achieved cannot responsibly be set in advance (please refer to OCC-443, parts (d) and (e)), the mechanism determines it from actual results, and an efficiently operating company returns more to customers than a fixed value would, both during the term and through the full rebasing of its relatively lower cost level at the next rate case. The design protects customers on the downside, and any reduction in Core Operating Expense per customer that improved near-term earnings would register against the benchmark and increase the dividend, converting that reduction into an automatic, growing customer credit.

Date Filed: September 22, 2026

Witness: Julia Frayer
Request from: Office of Consumer Counsel

Question:

(Total factor productivity) In Exhibit CLP-PBR-1, Page 32, LEI states that *"On the other hand, a longer term (e.g., more than 20 years) would also not capture significant changes in the industry such as widespread AMI deployment, distributed energy resources ("DERs"), increased cybersecurity requirements, resilience and climate adaptation investments, and modern vegetation management practices."*.

a. Please identify each formal statistical test for structural breaks or parameter instability performed by LEI across the 2005–2024 study period to evaluate the timing and statistical significance of the alleged structural breaks. If no such tests were conducted, please explain the empirical basis for LEI's assertion.

b. Please provide any empirical or quantitative analysis performed by LEI or the Company evaluating the specific impact of AMI deployment, automation, and DER integration on OM&A efficiency and labor productivity.

c. Given that large-scale AMI deployment, advanced DER integration, and heightened cybersecurity requirements emerged primarily within the last 5 to 10 years, please explain why a 20-year historical average (2005–2024)—which incorporates a decade of pre-AMI/pre-DER data—is more representative of forward-looking operating conditions than a 5- or 10-year period.

Response:

a. LEI did not perform a formal statistical test for structural breaks or parameter instability in selecting the 2005–2024 study period, as previously stated in the Company's response to information request OCC-538[i], in subpart d. The Industry TFP Study uses index-number techniques to measure changes in aggregate industry inputs and outputs over time; it does not estimate statistical relationships or coefficients whose stability would need to be tested.

The statement in Exhibit CLP-PBR-1, was not intended to assert that a discrete statistical structural break occurred in 2005, or in any other particular year. Rather, the cited developments-such as AMI deployment, DER integration, cybersecurity requirements, resilience and climate-adaptation investments, and modern vegetation-management

practices-were examples of material changes in industry operating conditions that have occurred over time.

As explained in the responses to OCC-534[ii] and OCC-538 and in Section 2.4 of Exhibit CLP-PBR-2, LEI selected the 2005-2024 period to balance the benefits of a sufficiently long period for measuring long-run industry productivity trends with the relevance of the historical period to current and prospective industry conditions. LEI also evaluated 10-, 15, and 20-year productivity trends as sensitivity periods.

b. LEI did not perform a causal or econometric analysis that separately quantified the effect of AMI deployment, distribution automation, or DER integration on OM&A efficiency or labor productivity. Based on information LEI has available, it would not be possible to pinpoint in time when these specific events and changes occurred for every individual EDC and therefore make it intractable to perform such a study. The Industry TFP Study was designed to measure the aggregate historical productivity trend of the electric distribution industry, rather than to attribute that trend to individual technologies or operational initiatives.

   OM&A includes both labor and non-labor costs, and the available FERC Form 1 data do not separately identify the labor and non-labor costs attributable to AMI, distribution automation, or DER integration. As a result, LEI could not isolate the effects of those individual initiatives on labor productivity.

c. LEI does not contend that every year from 2005 through 2024 is equally representative of each technology or operating practice expected during the PBMRP term. Rather, the purpose of the selected period is to estimate a representative long-run industry productivity trend. As explained in response to part (a) and in the Company's responses to OCC-534 and OCC-538, LEI selected the 20-year period to balance relevance to current industry conditions with the need to reduce sensitivity to short-term volatility and one-off events. For the overall TFP analysis, a longer period also reduces the influence of uneven capital-investment timing, while for OM&A productivity it reduces sensitivity to unusual expense years or unusual operating circumstances. The selected period remains recent enough to reflect evolving industry conditions while providing a broader basis for estimating the long-run productivity trend.

   A five-year period would contain only four annual year-over-year productivity observations, and a ten-year period would contain nine data points, making those estimates more sensitive to individual years and short-term conditions. In contrast, the selected 2005–2024 period contains 19 annual growth observations. LEI nevertheless presented shorter-period results as sensitivities rather than selecting among time periods after observing their results.

Prior Referenced Response:

[i] OCC-538 Question:

Performance Based Ratemaking Panel Exhibit CLP-PBR-1

Please provide a sensitivity analysis showing the effect of unusually volatile pandemic-period observations on LEI's reported 2005–2024 average OM&A PFP growth rate of -0.03%. At a minimum, please provide:

a. The average OM&A PFP growth rate excluding the 2019–2020 observation;
b. The average OM&A PFP growth rate excluding both the 2019–2020 and 2020–2021 observations;
c. The median annual OM&A PFP growth rate over the 2005–2024 study period; and
d. An explanation of whether LEI performed any outlier, structural-break, or other sensitivity analysis to determine whether the long-run OM&A PFP result is representative of expected productivity during the Company's proposed PBMRP term.

OCC-538 Response:

a. Please refer to OCC-445[i]. As mentioned, "LEI does not consider excluding the 2019–2020 observation to be an appropriate sensitivity for purposes of estimating the industry OM&A PFP trend. The purpose of the TFP/PFP study is to measure industry productivity performance over time".
b. Please refer to the response to subpart (a).
c. The median annual OM&A PFP observation over the time horizon of 2005 to 2024 is approximately 0.02%. Please refer to Exhibit CLP-PBR-2A, TFP_Calc tab, cells BN16:BN34.
d. LEI did not perform a formal structural-break or outlier test for the TFP study. As explained in OCC-445, and OCC-446[ii], LEI does not consider selective exclusion of individual observations as an appropriate basis for estimating the long-run industry productivity trend.

[ii] OCC-534 Question:

Please explain the statement in Exhibit CLP-PBR-1, that the average OM&A PFP growth rate for 2015–2024 is -0.03% (page 64), with the results reported in Figure 5, LEI's Industry TFP results (2005-2024), which report an average OM&A PFP growth rate of -0.03% for 2005–2024, 0.30% for 2010–2024, and -0.35% for 2015–2024. In your response:

a. Identify the study period and OM&A PFP result actually relied upon to establish the proposed -0.03% X Factor;
b. Explain the basis for selecting that study period over the alternative periods presented in Exhibit CLP-PBR-1;
c. State whether the reference to 2015–2024 in Exhibit CLP-PBR-1, is an error and, if so, provide the corrected testimony; and
d. Explain whether selection of a different study period would change the Company's proposed X Factor and, if not, why not.
e. Please provide all calculations, workpapers, and supporting data used to derive the –0.03% X Factor in an Excel format.

OCC-534 Response:

a. The Company relied on the 20-calendar-year period from 2005 through 2024, which encompasses a total of 19 annual year-over-year growth observations. Please refer to Figure 22, on page 47, of Exhibit CLP-PBR-2.
b. As stated in Section 2.4, of Exhibit CLP-PBR 2, "the 20-year study period overcomes the high variability of year-on-year trends but is also not so long term as to capture "stale" industry trends that would not likely repeat themselves in the future." Further, as discussed in that section, the "last 20 years reflect the changing business circumstances in the electric distribution industry, which are also going to continue to drive productivity in the next several years." Please also refer to OCC-441.
c. Yes. The phrase "2015-2024" in the identified sentence contains a typographical error. The corrected sentence should read: "Based on LEI's Industry TFP Study, the average OM&A PFP growth rate for 2005-2024 is negative 0.03% (or -0.03%), which is the proposed X Factor." No numerical correction to the proposed X Factor is required.
d. A different study period would produce a different measured historical OM&A PFP rate, as shown in Figure 22, of Exhibit CLP-PBR-2. However, LEI would not recommend using a different study period for purposes of setting the X Factor. As discussed in response to part (b) and Section 2.4, of Exhibit CLP-PBR-2, LEI considers the 2005–2024 period appropriate because it is sufficiently long enough to reduce the influence of short-term volatility and one-off events, while remaining recent enough to reflect industry conditions relevant to the prospective PBR term. Accordingly, LEI continues to recommend a -0.03% value for the X factor that would be applied to the OM&A portion of revenue requirement.
e. Please refer to Exhibit CLP-PBR-2a, the native workpapers supporting the Industry TFP Study.

Date Filed: September 21, 2026

Witness: Julia Frayer
Request from: Office of Consumer Counsel

Question:

(Total factor productivity) Refer to Exhibit CLP-PBR-1, pp. 43-44. Testimony suggests that the LEI's industry TFP study is aligned with TFPs for the EDC sector in New Hampshire, Alberta, and Massachusetts. Explain whether each of the x-factors provided for these three examples were calculated for O&M only or both O&M and capex.

Response:

The industry TFP measures cited for New Hampshire, Alberta, and Massachusetts on pages 43-44 in Exhibit CLP-PBR-1 were total factor productivity measures that included both O&M and capital inputs; they were not O&M-only partial factor productivity measures.

LEI cited these studies to demonstrate that **negative industry-wide TFP trends** have also been observed in other recent electric distribution TFP studies. LEI did not cite these other studies to suggest that the design or scope of the X Factor in each jurisdiction was identical to CL&P's proposal. Under CL&P's PBMRP proposal, the X Factor is applied only to OM&A, and LEI therefore recommends using the long term industry OM&A PFP trend of -0.03% from its industry TFP study to calibrate the X Factor.

Date Filed: September 21, 2026

Witness: Douglas P. Horton
Request from: Office of Consumer Counsel

Question:

(Performance incentive mechanisms) Refer to Exhibit CLP-PBR-1, p. 66. As stated, the Company's PIM proposal for exposure to financial penalties is limited to an amount equal to 0.5% of the Company's total distribution revenues. How was this limit determined to be the maximum reasonable threshold for penalty exposure?

Response:

As explained in Exhibit CLP-ELP-1, at page 115, the Company proposes to establish a maximum financial penalty that is allocated to each PIM, annually. The maximum financial penalty pool is $10 million annually, which is equal to the exogenous cost threshold. The exogenous cost threshold of $10 million is intended to represent a point at which the exogenous cost change is significant to the Company in a given year. Setting the maximum financial penalty equal to the exogenous cost threshold ensures that the maximum penalty pool represents a significant financial risk but not an overly burdensome amount that may unnecessarily jeopardize the overall financial health of the Company.

For context, the Company's total level of operating and maintenance ("O&M") expense included in the cost of service is approximately $350 million, net of vegetation management expense and storm fund contributions. Thus, the amount of $10 million is approximately three percent of total O&M expense, which is comparable to the annual adjustment that would be allowed under the PBMRP at a three percent inflation rate. A *single* cost change rising to the level of three percent of total O&M expense would be a substantial change in circumstances and the Company does not expect to encounter *singular* cost changes equal to the rate of inflation on the total base of O&M expense on a regular or recurring basis.

The Company's proposed use of an exogenous cost materiality threshold in establishing the financial exposure associated with the proposed PIM framework is consistent with principles employed in PBR frameworks in other jurisdictions. Exogenous cost, or "Z-Factor", thresholds are commonly used to establish the level of financial materiality at which an event warrants extraordinary treatment, thereby distinguishing material impacts from the ordinary operating and business risks that a utility is expected to manage.

Please refer to the Company's response to information request OCC-430[i] for further information on the Company's proposed exogenous cost threshold.

Prior Referenced Response:

[i] OCC-430 Question:

Exhibit CLP-ELP-1 Please explain in detail how the Company determined that a threshold significance of 0.5% of total distribution revenue is appropriate for Z-Factor eligibility. Please explain why the Company proposes a 0.5% threshold rather than the 0.75% threshold proposed in the Docket No. 21-05-15RE01, Proposed Final Decision, and provide all analyses, calculations, benchmarks, or other information relied upon in selecting the proposed 0.5% threshold.

OCC-430 Response:

The 0.75% materiality threshold proposed in the Docket No. 21-05-15RE01, Proposed Final Decision is unnecessarily high, and inconsistent with other jurisdictions. Although the Company supports the intention of establishing a materiality threshold as a means of balancing administrative burden with the Company's need to cover the costs of service, including those over which it has no control, a materiality threshold set too high actually renders the mechanism increasingly ineffective, raising the likelihood that the utility cannot commit to the PBR stay-out because it will be unable to obtain a fair or reasonable level of recovery of its operating costs, also barring customers from benefitting from the efficiency gains that come from an extended stay-out.1

In the extreme, a materiality threshold of 10%, for example, would indicate that for an event to qualify as exogenous in terms of its materiality, it must be at least $192.19 million ($1,921.9 million revenue requirement x 10%, using the Company's cost of service filed in this proceeding). The likelihood of a single event meeting this criteria is exceedingly rare, meaning the Z-factor, in practice, would be effectively rendered moot.

Additionally, PURA provided no basis for how it determined a threshold of 0.75% was appropriate. In fact, in its proposed final decision, PURA stated, "[t]he threshold [of 0.75%] better aligns with the thresholds established in other PBR jurisdictions," and then provided the following footnote referencing those other jurisdictions, each one of which is substantially below the 0.75% it proposed:

> "*Hawaii set thresholds equivalent to 0.2%, 0.25%, and 0.28%; Ontario set a threshold equivalent to 0.5%; Massachusetts set a threshold equivalent to 0.37%; and Alberta Utilities Commission set a threshold equivalent to 0.25*%."2

The Company's proposed Z-Factor of 0.5% *is* more closely aligned to those other jurisdictions.

Date Filed: September 22, 2026

Witness: Julia Frayer
Request from: Office of Consumer Counsel

Question:

Please provide, for each EDC and each year included in LEI's Industry TFP Study and Benchmarking Study, all data and calculations used to determine the portion of A&G expense attributed to electric distribution operations, including:

a. Total reported A&G expense;
b. Total plant in service;
c. Electric distribution plant in service;
d. The resulting distribution plant share used to allocate A&G expense; and
e. The resulting amount of A&G expense included in OM&A for purposes of the TFP and benchmarking analyses.
f. Please provide the underlying data, sources, and calculations in an unlocked Excel workbook with formulas intact.

Response:

Please refer to OCC-563, Attachment 1, which provides the requested data for each EDC and year: the total reported A&G expense, total plant in service, electric distribution plant in service, the resulting distribution plant share, and the amount of A&G allocated to electric distribution operations. As described in Section 3.2 of Exhibit CLP-PBR-2, LEI calculated each utility's annual distribution plant share as electric distribution plant in service divided by total plant in service. LEI then applied that percentage to the utility's total reported A&G expense for the same year to estimate the portion of A&G attributable to electric distribution operations. The resulting allocated A&G expense was added to annual O&M expense to derive OM&A used in the Industry TFP Study and Benchmarking Study.

Date Filed: September 22, 2026

Witness: Douglas P. Horton and Julia Frayer
Request from: Office of Consumer Counsel

Question:

(Capital support mechanism) Refer to Exhibit CLP-ELP-1, p.101. "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." Provide a list of all instances known to the Company in which approved multiyear rate plans for utilities in other jurisdictions employ downward reconciliation of capital. In each instance, please provide the state, the utility, the applicable Rate Years for the approved multiyear rate plan. For each Rate Year, indicate whether utility costs were lower than what was approved, and how much was reconciled and returned to ratepayers (in dollars).

Response:

The Company is aware of approved multiyear rate plans for Central Maine Power Company ("CMP") and certain New York utilities—Consolidated Edison Company of New York, Inc. ("Con Edison"), Central Hudson Gas & Electric Corporation ("Central Hudson"), and Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk")—that include downward reconciliation mechanisms for plant additions or net plant. These mechanisms are not identical in all respects to the Company's proposed capital support mechanism. CMP's mechanism compares actual distribution plant additions with the forecast plant additions reflected in rates, while the New York mechanisms generally reconcile actual average net plant and the associated revenue requirement against approved targets. Depending on the particular mechanism, where the relevant actual plant or net-plant measure is below the applicable target or cumulative target, the associated revenue-requirement impact is reflected in a downward rate adjustment or deferred for the benefit of customers.

CMP (Maine). The Maine Public Utilities Commission approved a two-year rate plan for CMP covering Rate Year 1, ending July 31, 2024, and Rate Year 2, ending July 31, 2025, that included a downward-only plant addition reconciliation.[1] [2] Under the mechanism, actual distribution plant

[1] Maine Public Utilities Commission, *Central Maine Power Company, Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. § 307*, Docket No. 2022-00152, *Order Approving Stipulation*, June 6, 2023, Attachment 12.

[2] Following expiration of the two-year rate plan, CMP proposed a new five-year rate plan in 2025. CMP subsequently withdrew that filing. In April 2026, CMP filed a new distribution rate case in which it proposed to eliminate the reconciliations established under its prior rate plan and proposed a second phase of the proceeding to establish a new multiyear rate plan. As of September 2026, that proceeding remains pending. (Source: Maine Public

additions are compared with the forecast plant additions embedded in rates, and a downward revenue-requirement adjustment is calculated if actual plant is below the forecast.[3]

For Rate Year 1, CMP reported that its actual average plant balance exceeded the forecast average plant balance used to set distribution rates by approximately $127 million.[4] Accordingly, the downward reconciliation was not triggered and the mechanism had no impact on the distribution rate adjustment effective July 1, 2025.

Similarly, for Rate Year 2, CMP reported an actual average plant balance of approximately $2.716 billion compared with a forecast average plant balance of approximately $2.510 billion, or approximately $206 million above forecast.[5] Accordingly, the downward reconciliation was again not triggered, and CMP calculated a $0 revenue-requirement adjustment under the mechanism.[6] Thus, neither Rate Year 1 nor Rate Year 2 resulted in a downward revenue-requirement adjustment under the plant-addition reconciliation mechanism.

Con Edison (New York). Con Edison's approved 2026–2028 three-year electric rate plan includes a downward-only net plant reconciliation. Under the mechanism, Con Edison must defer for the benefit of customers the revenue-requirement impact, including carrying costs and depreciation, where actual expenditures for electric capital programs and projects result in actual average net plant below the applicable average electric plant-in-service balances reflected in rates. The reconciliation for Rate Years 1 through 3 is cumulative, and a downward revenue-requirement deferral is required only if the cumulative result over the 36-month rate-plan period is below the applicable cumulative target.[7] Accordingly, although the rate-year components of the reconciliation are calculated during the plan, any downward revenue-requirement deferral under

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Utilities Commission, *Central Maine Power Company, Request for Approval of Rate Case Filing,* Docket No. 2026-00043, Notice of Proceeding and Opportunity to Intervene, April 22, 2026, 1–2)

[3] Ibid.

[4] Maine Public Utilities Commission, *Central Maine Power Company, Request for Approval of Annual Compliance Filing*, Docket No. 2025-00018, Order Approving Stipulation, June 11, 2025, attached Stipulation § 4.P, 8–9; Central Maine Power Company, Stipulation Attachment 20, Plant Addition Reconciliation, 1. https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=129743&CaseNumber=2025-00018

[5] Central Maine Power Company, *2026 Annual Compliance Filing Master Exhibits*, Maine Public Utilities Commission Docket No. 2026-00011, Attachment 16, "Plant Addition Reconciliation." P. 1. https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=133197&CaseNumber=2026-00011

[6] Central Maine Power Company, *2026 Annual Compliance Filing, Maine Public Utilities Commission* Docket No. 2026-00011, February 17, 2026, 12; Central Maine Power Company, 2026 Annual Compliance Filing Master Exhibits, Attachment 16, "Plant Addition Reconciliation," 1-2.

[7] New York State Public Service Commission, *Order Adopting Terms of a Joint Proposal and Establishing Electric and Gas Rate Plans*, Cases 25-E-0072 and 25-G-0073 (issued and effective January 22, 2026), 55; attached Joint Proposal § D.1.a, 17–19.

this provision is determined based on the cumulative 36-month result rather than on a stand-alone rate-year basis.

Central Hudson (New York). Central Hudson's approved three-year rate plan, approved in August 2025 for the period through June 2028, continues a downward-only net plant reconciliation.[8] Under the mechanism, actual electric and gas net plant and depreciation expense are reconciled against the applicable targets, with the resulting revenue-requirement differences carried forward over the plan term. At the end of Rate Year 3, if the cumulative revenue-requirement impact from net plant and depreciation-expense differences is negative, Central Hudson must defer the amount for the benefit of customers, with carrying charges at the applicable pre-tax authorized rate of return.[9] Because the reconciliation is cumulative over the multiyear rate plan, the final cumulative customer deferral, if any, has not yet been determined.

Niagara Mohawk (New York). Niagara Mohawk's approved three-year rate plan covering April 1, 2025, through March 31, 2028, includes a downward-only electric net utility plant and depreciation expense reconciliation.[10] Each Rate Year, actual electric average net utility plant and the associated depreciation-expense revenue requirement are compared with approved targets, with the differences carried forward and summed at the end of Rate Year 3. If the cumulative reconciliation balance is negative at the end of Rate Year 3, Niagara Mohawk must defer the resulting revenue-requirement impact for the benefit of customers; if the cumulative reconciliation balance is positive, there is no deferral.[11] Accordingly, the final cumulative customer deferral, if any, will not be determined until the conclusion of Rate Year 3.

The Company also notes that a downward-only reconciliation was a feature of the incremental capital funding mechanism outlined in the Draft Decision issued in Docket No. 21-05-15RE01. Please refer to Docket No. 21-05-15RE01 Proposed Final Decision issued July 14, 2025, at 33.[12]

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[8] New York State Public Service Commission, *Order Adopting Terms of a Joint Proposal and Establishing Electric and Gas Rate Plans,* Cases 24-E-0461 and 24-G-0462 (issued and effective August 14, 2025), 59–60; New York State Department of Public Service Staff, Staff Statement in Support of the Joint Proposal, Cases 24-E-0461 and 24-G-0462 (May 23, 2025), 39–40.

[9] Ibid.

[10] New York State Public Service Commission, *Order Adopting Terms of Joint Proposal and Establishing Rate Plans,* Cases 24-E-0322 and 24-G-0323 (issued and effective August 14, 2025); Niagara Mohawk Power Corporation d/b/a National Grid et al., Joint Proposal, Cases 24-E-0322 and 24-G-0323 (April 25, 2025), § IV.11.1.11, 70–71. < https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B20E76D96-0000-C727-A6AB-C1690EEB4F65%7>; < https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BE08BA998-0000-C031-ABF4-BF2E66669E52%7D>

[11] Ibid.

[12] Connecticut Public Utilities Regulatory Authority, *PURA Investigation into Revenue Adjustment Mechanisms for a Performance-Based Regulation Framework*, Docket No. 21-05-15RE01, Draft Decision (July 14, 2025) https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/1555634f73ae53a685258cc7007a62fb?OpenDocument

Date Filed: September 22, 2026

Witness: Douglas P. Horton, Digaunto Chatterjee, Elli Ntakou, Julia Frayer, Matthew Nelson and Michael Goldman
Request from: Office of Consumer Counsel

Question:

(Total factor productivity) Refer to Exhibit CLP-ELP-2, Page 35, Foot note 52, LEI states that "*LEI also evaluated the Handy-Whitman Index (" HWI") of public utility construction costs as a potential capital price deflator. LEI ultimately selected the BLS Producer Price Index for two primary reasons. First, unlike the PPI, the HWI is proprietary, and its w1derlying methodology and data are not publicly disclosed, making it difficult to independently evaluate or replicate the resulting estimates. Second, sensitivity testing demonstrated that use of the HWI generated implausibly large real retirement values for certain utilities, resulting in negative estimates of real capital stock under the perpetual inventory method. These outcomes are not economically plausible ai1d would have necessitated the exclusion of affected utilities from the sample. The issue became more pronounced under assumptions of longer asset service lives (i.e., 40, 45, and 50 years).*" Please explain the Company's use of the Handy-Whitman Index ("HWI") in Exhibit CLP-IAP-7 with LEI's decision not to use HWI as a capital price deflator in Exhibit CLP-PBR-2. Specifically:

a. Please explain why the Company considers HWI to more accurately reflect how inflation impacts Distribution Companies within the region and to be the appropriate inflation factor for the Exhibit CLP-IAP-7 - RE08 affordability test, while LEI determined that HWI presented methodological and data limitations, including lack of transparency and replicability and, in certain applications, economically implausible estimates of real capital stock.
b. Please recalculate Tables 3 and 4 of Exhibit CLP-IAP-7 using a consistent inflation measure for both historical and forecast spending, including, at minimum, HWI and the BLS PPI used by LEI in Exhibit CLP-PBR-2, and provide the resulting affordability threshold and percentage of the threshold represented by the proposed LRP.

Response:

As stated in Exhibit CLP-IAP-1 and Exhibit CLP-IAP-7, the Company does not agree that the RE08 affordability test is a sound approach for determining whether utility service is affordable. The test is allegedly designed to account for "reasonable escalation factors," however, determining those "factors" is a difficult exercise and, in any event, would need to account for multiple externalities, such as inflation, infrastructure aging, exogenous grid stressors like weather events and electrification and standardized equipment sizes, among numerous other factors.

The Company's testimony in CLP-IAP-1 demonstrates that it seeks to balance affordability and reliability, with a recognition that these concepts are inter-related and move together over the relevant time horizon. As previously stated, a system that is allowed to degrade does not become more affordable; it becomes less reliable and, in time, more expensive to maintain and fix.

The Company applied the RE08 affordability test illustratively, as a condition of the Order and, as shown in Exhibit CLP-IAP-7, the proposed capital plan is within the resulting threshold. Although the Company complied with the RE08 affordability test requirements, the core premise of the affordability test is that historical spending dictates future spending adjusted for inflation. This does not account for the fact that maintaining historical performance, as the PBMRP performance framework requires, comes at an increasingly higher cost, for a multitude of reasons including inflation. However, even if adjusting inflation provided the Company with additional revenue support to do the same type of project each year as a theoretical matter -- what matters is the scale and magnitude of infrastructure investment or upgrades is needed each year, along with numerous other drivers of infrastructure cost that are not necessarily captured in inflation measures.

As infrastructure ages, significantly more assets need to be replaced either proactively or as emergent failures. Short-term underinvestment increases the age and the number of failures of the assets that then need to be replaced as emergent failures. Other important factors that drive costs up are regulatory, safety and environmental constraints and considerations. For example, new equipment and work method standards to promote customer and worker safety and resilience mean that, even if the Company were to perform the same project today as it did years ago, it would cost more today for these reasons, even if the costs were to be adjusted for inflation.

To illustrate this practicality, Eversource's ReBOT tool that determines the optimal reliability mitigation for each eligible zone and thereby constructs a cost-optimal reliability program, demonstrates that the same dollar spend results in progressively lower benefits to reliability metrics. This is because, as zones with multiple events or customers impacted and cheaper solutions are addressed, more costly solutions are the only ways remaining to retain or further improve reliability metrics. For example, the model will prioritize short zones of bare conductor with many events or customers impacted so that a less costly reconductoring project will improve reliability. Once all these opportune zones are addressed, what remains are longer zones, with less events and customers impacted, so cost per unit of reliability improvement will increase.

Instead of a singular affordability test, the Company submits that it is more appropriate to review affordability and reliability through a balancing lens, aiming to avoid both overinvestment (which can increase costs without commensurate benefits) and underinvestment (which can erode reliability, create future cost pressures, and ultimately harm customers). Ultimately, while the Company agrees with the overall emphasis on affordability stemming from RE08, as well as RE08's reliability framework, it does not agree that the inflation-based affordability test is a valid tool for determining the affordability of a capital plan.

With respect to inflation factors, LEI stated a specific concern with the HWI for estimating long term aspects of real capital stock. However, the Company continues to support HWI as the most reliable and appropriate set of inflation factors for the utility sector. The BLS PPI is a broad, national macroeconomic indicator tracking average price changes across thousands of products and industries, and the GDP Deflator Index considers economy-wide measures such as personal consumption expenditures, private domestic investment, exports of goods and services, and government expenditures and consumption. The HWI is a highly specialized index tailored exclusively to the public utility construction sector and to specific regions. Compared to other inflation indices, the HWI more accurately reflects how inflation impacts distribution companies within the region, and therefore, is the appropriate inflation factor for general utility use and any application of the RE08 affordability test.

PURA has previously noted that "the HW Index better reflects costs of utilities doing business..." Application of the United Illuminating Company to Amend its Rate Schedule, Docket No. 24-10-04, at 43 (October 28, 2025) ("UI 2025 Decision"). As PURA states, "The Handy-Whitman Index reflects escalation of utility costs over time and has an index specific to northeast utilities … the HW Index considers utility construction costs by FERC plant account (e.g., transformers, meters, overhead conductors, station equipment)." Id.

There is also no inconsistency between LEI's use of the BLS PPI in the TFP Study and the Company's use of HWI in the affordability analysis because the indices are used for entirely different analytical purposes. HWI is specifically designed to measure changes in utility construction costs and reflects cost trends for utility-specific inputs, including labor, materials, and equipment associated with distribution facilities such as station equipment, poles, conductors, conduit, transformers, and meters.

In the Industry TFP study, LEI required a capital price deflator to convert historical nominal capital additions and retirements into a consistent measure of real capital quantity for use in the perpetual inventory method. Because the reported gross book value of utility assets reflects assets acquired in different years and therefore at different historical price levels, the additions and retirements must be deflated before they can be incorporated into the real capital stock calculation. This application requires the price index to be applied over a relatively long historical period and is mathematically sensitive to the interaction among the price index, asset vintages, retirements, and assumed asset service lives. LEI had collected and tested using HWI but found it could result in mathematical irregularities because of the methodology, which would in turn impact the breadth of the industry TFP study (the number of EDCs that could be included).

As a consequence, balancing the availability of data with the constraints of the methodology, LEI determined that the BLS PPI was an appropriate index for the specific purpose of constructing a real capital-stock quantity under its TFP methodology. LEI's use of the BLS PPI, therefore supported expressing the resulting capital quantities in constant 1988 dollars. This is distinctly

different from the analysis being contemplated under RE08 affordability test, which is to inflate capital spending from 2015 to 2025 terms.

For most other purposes, including the RE08 affordability test, HWI is the most appropriate inflation index for the industry, as it takes into account utility-specific costs in the Northeast.

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Office of Consumer Counsel

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.

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: September 21, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-TSP-2, Page 24, Eversource notes that "*Collectively, historical system analysis, economic forecasting, distributed energy resource modeling, electric vehicle forecasting, energy efficiency projections, and large customer analyses are integrated into the Company's substation-level forecasts and long-term demand assessments*."

Please share how the impacts from its existing demand response programs including but not limited to: Connected Solutions, Energy Storage Solutions, Electric Vehicle Managed Charging2 are incorporated into the forecast.

Response:

Impacts from Demand Management programs are captured in the forecast through the economic trend forecast component. That forecast component relies on the last 10-years of station peaks as recorded. Programs that impact those station peaks drive down the registered peak considered in the model.

Impacts from future demand response programs are not incorporated into the forecast and are not included in any Energy Efficiency adjustments made to the forecast. Future programs will be considered through the model once their impact to system peaks become quantifiable. Fundamentally, demand response of any form is a solution to an identified need and can only be considered as a permanent need reduction once the programs work, have quantifiable impacts, and secure funding for long duration operations.

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-TSP-3, Page 42, Eversource provides a table with investment categories by year. Please clarify how the following categories are mutually exclusive:

a. Reliability
b. Capacity
c. Emergent
d. Asset Health

Response:

Projects and programs shown in Exhibit CLP-TSP-3, at 42, are placed into a category by the main driver for the scope of work, although the project and/or programs may resolve multiple system concerns. For example the identified need to begin project or program development could be identified as capacity, however, a secondary driver could be asset health. In this instance the investment would be placed in the capacity category corresponding to the main driver of the work, although it resolves multiple system concerns such as asset health. The project and program investments in each of the categories are only accounted for in that category and are not included in additional categories. Exhibit CLP-TSP-3, pages 45 through 95 give additional information to describe the categories noted.

a. Reliability projects are work on the system associated with improving or maintaining SAIDI and SAIFI metrics. Projects in this category could also include double pole removals and the smart switch program.

b. Capacity projects are created to prevent equipment damage due to thermal overloads which could result in customer outages, while also providing operational flexibility to enable outages to be isolated and restored through alternate sources based on Eversource design criteria. They address peak load and capacity needs across the distribution system.

c. Emergent project work includes items identified through routine inspections and maintenance as well as emergent/emergency equipment replacements in a substation or on the overhead and underground distribution system.

d. Asset Health includes the replacement of aging or obsolete equipment that has reached the end of its useful life in order to maintain safe and reliable system performance. Within this scope, key asset types include transformers, switchgear, poles, PILC, conductor, cables, breakers, batteries, reclosers, station service transformers, protective relays, gas monitors, and switches for example. The need for replacement is determined based on inspections, testing, equipment age, safety considerations, operating performance, changes in standards, equipment obsolescence, and spare parts availability.

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-TSP-3, Page 48, Eversource provides a table with investment categories by year. For each line item in the table, please provide a brief description of what investments are included in the line item, as well as how the line item is mutually exclusive from the other rows in the table.

Response:

Page 48 of Exhibit CLP-TSP-3 gives the general project and program categories to give insights into the Distribution Substation Capital Plan portion of the Targeted System Performance Plan.

Projects and programs are placed into a category by the main driver for the scope of work. The identified need to begin project or program development could be identified as capacity and a secondary driver could be asset health. The investment would be placed in the capacity category with that being the main driver of the work although it resolves multiple system concerns. The project and program investments in each of the categories are only accounted for in that category and are not included in additional categories.

Aging Infrastructure Replacements: This investment category includes projects and programs that support the replacement of aging or obsolete substation equipment that has reached the end of its useful life in order to maintain safe and reliable system performance. At substations, distribution assets include a range of equipment, depending on the type of station, and can include circuit breakers, bus work, relays, reactors, capacitors, switches, termination structures, control enclosures, protection and control equipment, power supply systems, physical and cyber security assets, cables and connecters, duct bank and cable trench, etc. The need for replacement is determined based on inspections, testing, equipment age, safety considerations, operating performance, changes in standards, equipment obsolescence, and spare parts availability.

Inspection/Replacement Failed Equipment: This investment category is similar to Aging Infrastructure Replacements but differs in that it includes equipment replacements that can be completed under the annual funding policies and within a shorter time period than a typical project.

Substation Transformer Asset Health: This investment category of projects includes replacement of the distribution substation transformer fleet. These units consist of Bulk transformers and Distribution transformers. Bulk transformers are installed at bulk distribution

substations that are directly supplied from the transmission system (typically 115 kV) and step voltage down to distribution levels (typically 23 kV, 13.2 kV, or 4.8 kV). Distribution transformers are installed at distribution substations supplied by other distribution systems (e.g., 23 kV) and step voltages down to supply customers. There are 314 transformers currently installed across CT distribution system. The present fleet average age is 43 years old with the oldest transformer in-service at 85 years old. Based on age records of distribution substation transformers, a portion of the fleet, about 56% have exceeded the 40-year expected service life of a transformer. This means that without repair or replacement, as each transformer ages, 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 within this category of investments.

Substation Transformer DSCADA LTC Controls: This investment category was established to track the installation of DSCADA Load Tap Changer (LTC) Automation at all remaining Eversource CT sites currently utilizing the obsolete radio-controlled system for substation LTC voltage reduction. The existing 1970's radio-controlled systems installed on Eversource transformers were obsolete and failing. Replacement radio units are not available as the system components are no longer supported by the manufacturer. The existing radio-controlled system could no longer support the required voltage reduction capability.

Switchgear Asset Health: This investment category includes projects including the replacement of substation switchgear units that have aging equipment and deteriorating foundation conditions. These projects are needed to address concerns about long-term reliability, safety, and the ability of the equipment to continue operating as intended. Switchgear condition indicators typically include, but are not limited to, asset age, environmental impacts, short circuit margin, operational integrity (operating location in substation and frequency of operation), general model obsolescence (ability to obtain trained service personnel and replacement parts), and field assessment data (maintenance notifications/issues for breaker components like bushings, mechanism, contacts, and dielectric media). In many cases, the condition of the switchgear itself, combined with structural issues affecting its foundation, increases the risk of equipment failure or service interruptions. Replacing this equipment helps ensure the electric system remains dependable and supports safe operation for utility personnel. These investments also help to maintain service reliability and prepare the electric distribution system to meet future operational needs.

Capital Tool Purchases: This investment category includes capital tool purchases to support the field personnel working in electrical substations. Capital tool purchases must meet the capitalization threshold requirement of $500 per unit cost. Exceptions to this $500 threshold include items which are purchased “in bulk” as defined in APS-08 Capital Versus Expense Criteria.

Emergent Equipment Failures/Replacements: This investment category is similar to Aging Infrastructure Replacements but differs in that it includes emergent equipment failure replacements

that can be completed under the annual funding policies and within a shorter time period than a typical project.

Environmental Equipment Replacements: This investment category includes projects to specifically replace aging oil filled substation equipment such as oil filled circuit breakers and oil filled substation reclosers. If a circuit breaker or recloser does not operate properly, the consequences can include serious safety risks for workers, reduced system reliability, environmental impacts such as oil leaks or spills, and damage to nearby equipment. In the case of a circuit breaker failure, failure to interrupt a fault, or experiences internal failure, the next available circuit breaker must operate. Depending on the design of the substation where the circuit breaker is installed, the severity of its unavailability will vary. When a recloser does not work properly, it can prevent automated systems from responding to problems leading to increased Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Duration Index (SAIDI) minutes. A failed circuit breaker or recloser can also affect planned work, including efforts to safely isolate or restore power to lines and substations.

Substation Capacity/System Planning: This investment category includes projects to address normal and emergency substation overloads within the 10-year planning horizon and those created to resolve violations of the Distribution System Planning Guide (DSPG).[1] Solution alternatives are developed with varying levels of complexity and may include a combination of balancing loading across the system, replacing or upgrading limiting equipment, adding new equipment or expanding an existing substation, installing non-wires alternatives, and/or developing a new substation to support the identified needs of the area.

Incremental Aging Infrastructure Replacements: This investment category is the incremental funding required to replace additional aging substation equipment beyond what is included in the Sustained Performance Plan to achieve the Targeted System Performance Plan investment.

Incremental Substation Transformer Asset Health: This investment category is the incremental funding required to replace additional aging substation transformers beyond what is included in the Sustained Performance Plan to achieve the Targeted System Performance Plan investment.

[1] Refer to CLF-SC-023, Attachment 1, for the Eversource Distribution System Planning Guide 2020 Rev. 0.

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling and Elli Ntakou
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-TSP-3, Pages 40, 46, and 50 Eversource lists forecasted impacts to the system by spending scenario. For each listed impact on slides 40, 46, and 50, please share how Eversource plans to measure and monitor the impact over the 5-year spending period?

Response:

For reliability performance, the Company will measure and monitor reliability performance using standard and emerging reliability metrics, like SAIDI, SAIFI, CEMI and CELID. These metrics can be calculated with multiple different methodologies; for example, there is a CT-specific calculation for blue-sky SAIDI and SAIFI based on a certain method of delineating major storms. Eversource's Outage Management System retains all interruption records, with the impacts to these metrics; Customers Impacted and Customer Minutes of Interruption per event. These metrics that measure and monitor reliability performance will be compared to the targets for PBR. For example, SAIDI and SAIFI will be compared to the 2022-2026 historical average plus one standard deviation. Accelerated investments in asset health (replacement of bare overhead Cu conductor, right-of-way rebuilds, and underground paper-in-lead-cable replacement), smart switches and resiliency combined with The Company's core investment to mitigate SAIDI and SAIFI will drive improvements in reliability for both blue sky and storm performance.

For resilience, the Company will monitor performance during major storms, measuring using metrics like all-in SAIDI and number of events. Importantly, major storm performance is a multi-input function where Company actions as well as exogenous factors drive system performance. Other aspects of TSP are also intended to improve storm performance and may be difficult to delineate the impacts of those to resilience metrics. For example, the Company's proposed routing optimization for storm crews and for its outage prediction models critically impact storm performance. It is important to note that as performance improves, the threshold for major storms becomes higher (i.e., less storms will qualify as major storms), so a normalization to account for the sliding threshold may be required to baseline and compare performance.

For distribution automation, the Company will estimate performance benefits of reclosing devices by assuming that each momentary event on these devices would have been a sustained interruption if the protective device was not capable of reclosing automatically. For example, in CLP-TSP-2 p.

30, it is estimated that 1.1M customers were spared from experiencing a sustained interruption in 2025 due to reclosers.

Exhibit CLP-TSP-3, Page 46 provides information describing the different investment levels and their general impact to the distribution substation project portfolio. The projects within the Targeted System Performance Plan will be budgeted and monitored throughout their life cycle. The projects initiated will be reviewed against the initiatives noted and tracked through the project approval processes through to completion. Additionally, the transformer average fleet age and oldest age objectives will be tracked periodically to confirm the projects created and completed are moving us toward the set goals.

Date Filed: September 22, 2026

Witness: Douglas P. Horton
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-AMI-1, Page 27, Eversource "*proposes to include AMI capital costs as eligible capital costs to be recovered and reconciled in the proposed PBMRP capital funding mechanism*." However, it proposes to recover incremental O&M costs and legacy meter infrastructure costs using securitization. Please explain why AMI capital costs should not also be recovered using securitization.

Response:

Please refer to OCC-571, Attachment 1 and OCC-571, Attachment 2, for a comprehensive discussion on the benefits, costs and appropriate use of securitization as a financing instrument for utility costs.

- Attachment 1 is a report prepared by Atrium Economics that was jointly sponsored by the Company's Massachusetts operating affiliates and other Massachusetts LDCs. The report was prepared for the purpose of explaining why securitization financing is not an appropriate or viable financing vehicle for ongoing utility investments.

- Attachment 2 is a legal memorandum prepared by the Company in relation to draft legislation in Massachusetts contemplating the securitization of electric-system upgrades to support electrification and grid-modernization assets.

Both reports explain the reasons that securitization is generally not appropriate when costs are ongoing, operational, or "business-as-usual." Examples include routine capital investments, annual maintenance, or safety-related replacements that occur every year, which would encompass the new metering system and associated back-office information systems that will constitute Advanced Metering Infrastructure on the Company's system in Connecticut. Outside of certain extraordinary circumstances, ***operating*** utility assets cannot be securitized.

As explained most directly in Attachment 2, securitization requires establishment of a bankruptcy-remote special purpose entity (an "SPE") that acquires the right to impose and collection the rate reduction bond charge from the related utility through a true sale and then issues bonds secured by a first-priority lien on that right. An investor-owned utility cannot transfer physical assets to a securitization SPE because those assets require continuous capital investment that a passive, limited-purpose entity cannot fund. Instead, securitization is a solution that involves an intangible cash flow right that requires no maintenance or reinvestment, such as in the circumstances of storm

restoration costs, stranded meter costs, stranded generating assets or other costs that are essentially one-time costs that constitute a debt owed by customers to the utility with no ongoing maintenance, repair or investment required or applicable.

The primary barrier to the securitization of utility operating assets is the capital maintenance problem. Physical utility infrastructure requires continuous capital investment to maintain operational capability and regulatory compliance. A securitization SPE cannot fund such capital because it cannot raise equity, issue additional debt, borrow, retain earnings, or contract for maintenance work. Physical assets placed in an SPE would inevitably deteriorate and Moody's has specifically identified asset deterioration as a critical credit risk for utility systems. However, transferring assets to an SPE that are required for a utility to operate would prevent the utility from providing service using assets it controls. Moreover, even if physical assets were placed in the SPE, the SPE would not obtain the AAA credit rating that makes it possible to achieve the beneficial cost for customers. Attachment 1 explains other impacts that would occur for the utility's cost of capital in the event that this type of financing would apply for utility assets.

The transfer to an SPE of the intangible property to the rate reduction bond charge right works in relation to large deferred expenses that a utility may have, such as storm costs or the costs of "stranded" assets, no longer used and useful for utility ratepayers because these types of "assets" do not depreciate, require no maintenance or capital and can be cleanly transferred through a true sale, thereby allowing the SPE to remain purely passive—all while the utility retains and continues to operate its physical system.

For AMI, this means that securitization is a possibility for the relatively significant one-time operating expenses that must be incurred to implement AMI across the State of Connecticut, as well as the costs of stranded meter investment. For the remainder of the cost that comes in the form of capital investment, it will not be possible to use securitization as the funding mechanism for that portion of the cost.

Date Filed: September 22, 2026

Witness: Douglas P. Horton and Jared A. Lawrence
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-AMI-2, Page 87, Eversource states that "*Recognizing that the AMI program requires sizable investments, Eversource embraces accountability for executing the program effectively and delivering the expected benefits to customers. Accordingly, Eversource proposes a performance metrics framework to provide transparency into both the success of the AMI deployment and the realization of benefits. In each category, the Company is proposing to report annually on a slate of metrics.*"

a. Given Eversource's stated commitment to accountability, please explain what would happen if the company does not achieve the expected performance metrics in the proposed time horizon.

Response:

As an initial matter, Eversource is fully committed to accountability and expects to have performance metrics that apply to the AMI implementation once it is clear that the AMI implementation plan will move forward and on what terms. In the event that PURA approves the AMI implementation plan on reasonable terms that the Company can work with, then it would be appropriate to structure a performance mechanism around a subset of the scorecard metrics described in pages 87-89 of the Company's AMI Plan.

In particular, the scorecard referenced on page 87 of the AMI Plan will provide transparency for the Company, PURA and other stakeholders to determine what stage the program has reached in relation to expected value; where alternative sources of value may be occurring; and whether program changes need to be made in response to changing conditions.

In addition, the Company is interested in exploring a symmetrical incentive/penalty mechanism that would incorporate project milestones and operational success components. The AMI deployment success mechanism would be evaluated by PURA at the completion of the last program milestone included in the mechanism. Milestones to be included in the AMI Deployment Success mechanism could incorporate the following:

- CIS Deployment
- MDMS Deployment

- Commence Meter Deployment
- Complete Meter Deployment
- Customer Alerts Enabled
- Customer Data Sharing Enabled
- Outage System Integration
- TVR capability

For the operational success, the Company is interested in exploring a "meter-to-cash" metric that would compare various performance points to pre-AMI levels. For clarity and to ensure that all customers continue to experience strong operational performance, the metrics would be calculated on the entire customer base (i.e. not limited to customers that have received their AMI meters). The measures included in the AMI Operational Success mechanism could be incorporated as follows:

- Meter Read Rate
- Bill Timeliness
- Bill Accuracy

In addition, the Company expects that there would be a customer outreach and education plan that could have symmetrical penalties and incentives surrounding the Company's efforts to communicate and influence customers in the ways that they can use AMI to achieve anticipated benefits.

At the same time, the Company cannot be accountable for factors and outcomes beyond its control, such as the extent to which customers actually adopt and utilize AMI features to achieve the full range of benefits enabled by AMI implementation. Applicable performance metrics pertaining to project milestones and operational success components would need to be designed to exclude the impact of factors outside of the Company's control and, conversely, to hold the Company accountable for those factors and outcomes that it does control.

The Company's expectation is that additional discussion will occur on these types of metrics once it is determined that AMI implementation will move forward and on what terms and timelines.

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-2 at 24, "At the bulk substation level, the Distribution System Planning Guide (DSPG) establishes criteria and guidelines for planning and design of bulk substations and distribution facilities."

a. Please provide a copy of the Distribution System Planning Guide (DSPG).

Response:

Please refer to CLF-SC-023, Attachment 1, for the Eversource Distribution System Planning Guide (DSPG) 2020 Rev. 0. The DSPG Rev.1.0 is currently under review and expected to be completed in 2026. The Company will supplement this response with Rev. 1.0 once finalized.

Date Filed: September 21, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-2 at 21-22, "Load Forecasting Data and Analytics."

a. Does the Company develop load forecasts at the substation, feeder or both?
b. Does the Company currently develop hourly load forecasts for its substations and feeders? If not, please describe the granularity of the Company's forecasts for substations and feeders.
c. Does the Company currently develop multiple scenarios for its load forecast? If so, please describe each of the scenarios.

Response:

a. The Company currently develops load forecasts at the substation level.

b. The Company currently develops an annual load forecast at the substation level based on the annual peak load hour for each substation. If a capacity need is identified based on that peak load forecast the Company creates a 24-hour load profile for each of the forecast years as needed.

c. The Company currently develops two scenarios for its load forecast. The Company produces a '50/50' and a '90/10' peak demand forecast. The '50/50' forecast is based on normal 10-year weather and has a 50 percent chance of being exceeded. The 90/10 forecast is the extreme weather scenario that only has a 10 percent chance of being exceeded. Only the 90/10 peak demand forecast is utilized for system planning.

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman, Gerhard Walker, and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-2 at 21-22, "Historical System Load Analysis."

a. Please describe the temporal granularity (i.e hourly etc.) of the historical loading information used to inform the Company's load forecast and whether this varies depending on location and data availability.
b. Please describe the percentage of substations and associated feeders with available 8760 hourly profiles. If some or all of the substations and associated feeders do not have 8760 hourly profiles, please describe whether and when the Company plans to have 8760 profiles available.

Response:

a. To create the substation peak forecast the Company relies on the peak hour values which are determined from 15 min SCADA data by substation and at the system level.

b. Please refer to the Company's response to information request OCC-587[i]. The Company currently does not create 8760 load forecast profiles. Where SCADA data is available[1], the Company does have historical 8760 "as measured" data. The Company currently has no plans absent approval of requested resources as presented in the Exhibit CLP-TSP-3 at 138. Here, the Company has outlined a pathway to develop the resources needed for the full capabilities to provide 8760 data within 18 to 24 months.

Prior Referenced Response:

[i] OCC-587 Question:

Refer to Exhibit CLP-TSP-3 at 138, "Advancing the Grid, Planning Analytics - Advanced Forecasting Tools."

a. Please describe the milestones and timelines to integrate this tool into distribution planning if approved.
b. Please explain why existing forecasting tools cannot generate forecasted 8760 load shapes across all levels: substation, transformer, and at circuit levels

[1] Currently, all CT bulk transformers have available SCADA data.

OCC-587 Response:

a. Based on the Company's experience, the procurement and deployment process will take 12-18 months from approval, and an addition 6 months to get the tools into full production.

b. Historically, time-series profile forecasts were not necessary to review capital projects and the single system peak was the most reliable forecast that could be produced. This is still valid today as the key input to capacity planning remains the magnitude of the peak, regardless of its time or date.

As iterated in the Company's responses to 21-05-15RE03 IDSP, there are also critical question on the validity and cost benefit of creating an 8760 forecast as an 8760 forecast, by its very nature, not only forecasts the peak load and time of that peak load, but also the weather and load over the entire year.

While such profiles can be and are useful for evaluating and sizing certain solutions (e.g., battery storage as an NWA, for which the Company can and does create 24-hour load profiles) they do not provide any incremental value for determining the scope of a substation project, and incur not insignificant incremental effort both on a technology and labor side. The Company has therefore not undertaken the full effort of creating such profiles given the incremental resources needed.

The existing tools the Company has in place were never designed nor intended to produce 8760 forecasts. This does not represent an insurmountable barrier but requires additional investments as the Company outlined in its comments to 21-05-15RE03 IDSP, which, without there being any documented proof in either proceeding that 8760 forecasts would quantifiably benefit the customer in a manner offsetting additional costs, requires the Authority to lay out cost recovery pathways for such efforts.

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-2 at 22-23, "Distributed Energy Resource Modeling" and "Electric Vehicle Forecasting."

a. Does the Company incorporate DER and EV flexibility potential into its load forecasts?
    i. If so, please describe what resources and flexibility assumptions are incorporated into the forecasts.
    ii. If not, please describe if and when the Company intends to incorporate DER and EV flexibility potential and assumptions into their forecasts.
b. Please describe any other flexibility assumptions the Company currently incorporates or plans to incorporate into their forecasts.

Response:

The term "flexibility" represents a general concept that can refer to demand management programs, EV charge management, TOU, existing or proposed/conceptual programs, targeted or statewide solutions, or customer flexibility as a standalone phenomenon with the introduction of new technologies.

The first distinction that must be made is between targeted and statewide programs and existing and proposed/conceptual programs. The forecast provides an overview of the system need (i.e., what the electric distribution and transmission system must be able to safely and reliably accommodate). In that forecast the Company considers impacts of DER (installed, in queue, and forecasted) and existing EE programs, such as demand response, that have shown quantifiable impact to system peaks. It does not consider anything above and beyond this, as anything that is not already in place is considered a solution to a need.

Charge management for electric vehicles in its current form relies on incentive payments to customers, a cost that must be considered for these programs. If the main benefit of such a program is to avoid transmission and distribution investments, the cost of the program must be considered against the infrastructure investments, especially as the program costs are yearly and ongoing. Placing such programs into the forecast would assume a foregone conclusion on the outcome of such an evaluation, and their efficacy.

Given the above context, the following are considered/not considered in the forecast:

Considered:

- Solar, installed, in queue, and forecasted
- Existing and funded EE programs and DR where they have shown consistent impact to peak

Not Considered:

- VPP dispatch of ESS
- Charge Management Programs

As stated above, the objective of the forecast is to demonstrate the system need, while flexibility options are, for the most part, solutions that incur actual costs. Unless programs are deployed statewide, funded, and have quantifiable and measurable impact to the peak, they are not considered in the forecast. The Company will incorporate any flexibility that meets those criteria in the forecast.

Date Filed: September 21, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 98, "Independent Process Monitor – Designated by PURA to review utility analyses and filings."

a. Please confirm the "utility analyses and filings" is the output of the Company implementing its internal NWA process to screen constraints for NWA viability.

Response:

Yes, the "utility analyses and filings" refer to the Company's Non-Wires Alternatives (NWA) Grid Needs Filing and Quarterly filings whereby the Company reports to PURA and the Process Monitor all their distribution needs projects and identify if there are any viable NWA options available for the project's specific needs. These filings are the output of the Company implementing its internal NWA process to screen system needs for NWA applicability.

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 99-100, "Eversource Internal NWA Process".

a. Please provide any documentation or details describing the specific "Standardize screening criteria, inputs and outputs" within the Company's internal NWA process.
b. Does the Company consider distributed generation, energy storage, demand response, energy efficiency, advanced grid technologies (i.e virtual power plants) and EV integration to be "proven and tested technologies"?

Response:

a. Please refer to OCC-578, Attachment 1, for the Company's NWA Framework. Since implementation of the new NWA process under Docket No. 24-08-08 Final Decision[1] the Company has been adhering to the process and criteria outlined therein.

b. The Company has stated in the NWS Program Manual[2] that NWS technologies include, but are not limited to, Distributed Generation ("DG"), Energy Storage ("ES"), Demand Response ("DR"), Energy Efficiency ("EE"), or any other distributed resources or innovative technologies that are proven and are commercially available.

[1] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0bb69f312fc7124085258bf7005581c5/$FILE/240808-121824.pdf
[2] https://www.eversource.com/docs/default-source/doing-business/pura-redlined-nws-program-manual-filing.pdf?sfvrsn=7706bf80_1

Date Filed: September 22, 2026

Witness: Douglas P. Horton, Digaunto Chatterjee, Lavelle A. Freeman, Juan Martinez, and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 101-106, "Non-Wires Alternative Projects, Eversource Battery Storage NWA Projects for Substation Capacity Relief".

a. What is the status of the non-wires alternative projects for Campville 14R and Frybook 14B?
    i. Have these projects been procured and are they in-service?
    ii. Is the Company seeking cost recovery for implemented projects or approval for proposed projects?
b. Please describe what DER control approach (e.g DERMS) the Company has or plans to use to dispatch battery storage.
c. Are the battery storage NWAs utility or third party owned?
d. Please describe the BCA methodology including the types of benefits quantified for the cost-effectiveness supplemental analysis.

Response:

a. i. These projects are still in conceptual status with an internal initial funding request approved. These projects have not yet undergone a full study and solution selection process. As part of this process, the NWA will be revaluated against other solutions to determine the final proposal.

    ii. These projects have not been implemented. The Company has included funding for the system needs driving these projects within the Sustained Performance capital program found on page 49 of exhibit CLP-TSP-1. As described elsewhere in this filing, the Company's proposed PBMRP plan is intended to provide revenue support for ongoing capital expenditures through application of the F-Factor in the PBMRP, subject to periodic and ongoing prudence reviews, application of the F-Factor cap, and downward-only reconciliation in the event actual overall plant-in-service is less than the capital expenditure forecast presented in Exhibit CLP-TSP-3.

b. If the NWA solution is selected for either project location, the Company will then determine DER controls during the detailed engineering stage.

c. The Company intends to operate the battery as the owner of the asset per PURA's Docket 24-08-08 Final Decision.[1]

However, the Company would solicit proposals through a formal RFP process on a battery storage solution from 3rd party vendors in order to implement the solution at the best available market pricing.

d. The benefit-cost model includes the costs and benefits associated with each project Campville14R and Fry brook 13B:

- Costs represent estimated Project costs and estimated Energy Markets revenues
- Benefits include:
  - Distribution Benefits: these benefits are associated with deferral of traditional distribution upgrade cost by targeting discharge as needed to resolve the localized distribution constraints.
  - System benefit: these benefits are related to ESS discharges targeting ISO system peak, which will result in Energy and Capacity benefits derived from the Avoided Energy Supply Cost.

[1] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0bb69f312fc7124085258bf7005581c5/$FILE/240808-121824.pdf

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman, Juan F. Martinez and Steven C. Osuch
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 11, "DER Enablement."

a. Please confirm the "150 MW from 9 station projects" whether these projects investments the Company is currently making or is requesting approval for in this rate case.
b. Please provide the following details regarding the "+110 MW from 7 additional projects."
    i. Please identify the 7 projects enabling the additional +110MW of DER capacity and whether these are load driven upgrades.

Response:

a. The nine station projects that enable 150 MW of DER capacity are currently part of the Company's long-range investment plan, and are in various stages of development or construction.

b. The seven additional projects are capacity (load) driven upgrades. Please see the table below for details on the 7 additional projects:

Substation	**Need**	**DER Enabled (MW's)**
Baldwin 13F	Capacity/ Load	15.01
Tracy 14M	Capacity/ Load	14.74
Triangle 11A	Capacity/ Load	19.43
Frybrook 13B	Capacity/ Load	15.01
Waterside 22M	Capacity/ Load	16.75
Flax Hill 24A	Capacity/ Load	15.01
Williams 9L	Capacity/ Load	15.01
Total		**110.96**

Date Filed: September 21, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling, Elli Ntakou and Gerhard Walker
Request from: Office of Consumer Counsel

Question:
Refer to Exhibit CLP-TSP-3 at 43, "Grid Services Compensation Fund - $38M"

a. Is the Grid Services Compensation Fund a new proposal seeking PURA approval as part of the targeted system performance plan? If not, please explain whether the Company has already made investments in this fund and whether it is seeking cost recovery in this rate case.
b. Please explain the scope of the Grid Services Compensation fund including what grid services will be procured, how grid services will be valued and compensated, what timeline grid services will be enabled and how stakeholders will be engaged to implement this proposal.
c. Please provide a breakdown of how the $38m will be allocated to implement this proposal.

Response:

a. Yes, the Grid Services Compensation Fund is a new proposal seeking PURA approval as part of the targeted system performance plan.

b. The purpose of the Grid Service Compensation Fund ("GSCF") is to compensate customer-owned front of the meter and behind the meter dispatchable DER and flexible loads for providing local grid services dispatched by real-time system operators using the Company's grid and aggregator Distributed Energy Resource Management System ("DERMS"). These offerings intend to leverage existing DER capacity to reduce distribution system infrastructure costs relative to traditional solutions. Specifically, DERs can provide valuable grid services for 1) deferral of infrastructure investments when DER dispatch can reliably reduce peak demand on local infrastructure that is slated for upgrade due to load growth; 2) for bridge-to-wires opportunities when DERs can provide flexible capacity to mitigate local reliability risks for which traditional infrastructure solutions cannot be deployed in time to meet need; and 3) provide voltage support services in support of increasing electricity delivery efficiency.

Influenced by the Company's experience with a similar program in Massachusetts as part of the Electric Sector Modernization Plan ("ESMP"), the GSCF would expand on the Company's successful ConnectedSolutions programs targeting ISO-NE system peak, to initiate offerings based on local system needs at the substation and feeder levels. The GSCF is intended to be implemented over a four-year period during which the Company would collect lessons learned on the efficacy and cost-effectiveness of various approaches to utilizing customer DER for local grid services. These learnings would support regulatory process to develop a longer-term mechanism to compensate customers for providing local grid services.

The Company would provide annual updates to PURA and stakeholders on implementation of the GSCF, including amounts spent on incentives and administration relative to the value created by the various use cases, including infrastructure deferral. In Massachusetts, the Company took part in a process led by the Massachusetts Center for Clean Energy (MassCEC) and with stakeholders which led to the release of the Grid Services Compensation Study ultimately informing the level of compensation for grid services.[1] The Company expects to leverage this work to evaluate how grid services will be valued and compensated specifically for CT use cases.

c. Costs associated with the GSCF are expected to include labor and outside services related to the administration and marketing of the programs; however, the Company expects that most of the budget will be used to compensate customers for providing local grid services.

[1] https://www.masscec.com/resources/grid-services-study

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling, Elli Ntakou and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 107-108, "Grid Modernization, Distributed Energy Resource Management System (DERMS)".

a. Please describe the DERMS capital and O&M spending spent to date and requested as part of the Targeted System Performance Plan.
b. Please confirm whether the Company is requesting funding for DERMS from the "Sustained Plan" and/or "Advancing the Grid" plan. If separate funding is requested within each plan, please provide a breakdown of the costs between the Sustained and Advancing the Grid plan.
c. Please describe the key milestones, status and estimated timelines for the Company to deploy a grid DERMS including the following:
    i. Please describe the status of procuring a grid DERMS system and/or aggregator/edge DERMS.
    ii. Please describe the status of completing the ADMS – DERMS Integration.
    iii. Please describe the extent to which the Company has established an architecture and technical operational requirements to standardize and implement a DERMS – DER Gateway.
    iv. Please describe whether the Company has developed a formal architecture for how grid DERMS will interact and integrate with an Aggregator or edge DERMS. Specifically, please indicate whether the Company intends to use a single or multiple aggregator/edge DERMS to dispatch aggregations and virtual power plants.
    v. Please describe the communications architecture the Company intends to use to communicate directly with third-party DERs and aggregator/edge-DERMS including the communication network and protocol.
    vi. Please describe whether the Company has a deployment plan for where and when DERMS will be deployed across its system and what use cases will be prioritized.

Response:

a. There has been no capital or O&M spent on DERMS investments to date.

The Company has initiated some enabling DERMS investments including ADMS power flow, aggregator DERMS (funded through the Company's energy efficiency program and utilized by the ConnectedSolutions program), as well as upgrades to the SCADA system. These investments support and are necessary precursors to the planned DERMS deployment.

The Company proposes spending $10.7 million in capital expenditures on its DERMS with no incremental O&M expenditures associated with this program.

b. The Company confirms that the proposed DERMS investments are fully included in the Sustained Plan. The same DERMS investments are included in the Targeted System Plan, and the Advancing the Grid Plan. The Advancing the Grid Plan includes incremental investments in a DERMS Demonstration. See the response to OCC-584[i] for a description of the DERMS Demonstration investment included in the Advancing the Grid proposal.

c. i. The Company has selected GE Vernova as its software provider for enterprise SCADA, ADMS, and DERMS in all its service territories, leveraging the benefits of an integrated real-time operating and control ecosystem. In CT, the Company has implemented the GE Vernova solution for SCADA and is in the process of implementing the integrated GE Vernova ADMS. The Company has not executed an agreement with GE Vernova to procure its DERMS solution for deployment in CT. As a part of its ConnectedSolutions program, the Company has executed agreements with several third-party aggregator DERMS to dispatch behind the meter DER and flexible load in support of ISO-NE system peak load reduction. The Company has not entered into agreements with any third-party aggregator DERMS for integration with a GE Vernova grid DERMS and/or provision of local grid services in CT.

ii. The Company plans to integrate its ADMS and DERMS solutions from GE Vernova which are designed to operate as an integrated solution. The ADMS-DERMS integration is currently in the planning stage.

iii. The Company intends to leverage a standardized DERMS architecture based on solutions previously deployed in other service territories. The Company is currently evaluating and developing the technical and operational requirements for the DERMS-DER gateway, including communication protocols.

iv. The Company is currently in the planning stage for designing the formal architecture governing the interaction between the grid DERMS and an aggregator/edge DERMS. The Company intends to leverage a standardized DERMS architecture based on solutions previously deployed in its Massachusetts service territory and is evaluating the use of multiple aggregator/edge DERMS providers. As the Company is in the planning phase, it has not yet finalized its aggregator/edge DERMS partners.

v. The Company is currently evaluating the communication architecture that will support direct communication with third-party DERs and aggregator/edge DERMS platforms. The communication network and associated protocols have not yet been finalized. As part of this effort, the Company is evaluating the use of IEEE 2030.5 for communication with both front-of-the-meter and behind-the-meter DERs.

vi. The Company estimates it would take approximately 18-months to implement a grid DERMS solution, including integration with third-party aggregator DERMS providers. Assuming a project start in mid-2027, the Company would have a fully functioning DERMS solution at the beginning of 2029. The initial use cases are expected to include flexible interconnection and local capacity relief at substations. The Company is still developing its deployment plan including the locations and sequencing of DERMS deployment across its distribution system in Connecticut.

Prior Referenced Response:

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[i] OCC-584 Question:

Refer to Exhibit CLP-TSP-1 at 68, "DERMS Demonstration – Demonstrate the value proposition of advanced DERMS capabilities, including (1) use of DER to increase system efficiency and reduce line losses; (2) integration of multiple types of DER in a microgrid application for critical load; and (3) investigation of lower cost approaches to communication and control of stand-alone solar and storage facilities integrated into the Company's centralized DERMS system."

a. Has the Company deployed DERMS and implemented any DERMS use cases to date?
b. Please describe how this DERMS demonstration will be coordinated with the implementation of the Grid Services Compensation Fund and Dynamic Flexible Interconnection.

OCC-584 Response:

a. Other than the use of its aggregator DERMS utilized for an ISO-New England system peak load reduction use case through the ConnectedSolutions program, the Company has not deployed DERMS or implemented DERMS use cases in its Connecticut service territory. In its western Massachusetts service territory, the Company deployed the first phase of a grid DERMS at the end of 2025 and is currently completing the second phase of the grid DERMS project with a target in-service date at the end of 2026. The Company is currently implementing foundational upgrades to its SCADA eECS and DMS systems in Eastern Massachusetts and is expecting to start a grid DERMS project there in early 2027. With respect to use cases, in western Massachusetts, the Company is currently utilizing its grid DERMS for weather-based operational forecasting,

providing real time system operators with hour- and day-ahead visibility into the impact of DER on power flows, including the impact of solar generation on equipment loading. In eastern Massachusetts, the Company conducted its first locational demand response program in Summer 2026, utilizing its aggregator DERMS to reduce load during peak events at three substations in the Boston area with identified risk of overload. The Boston substation peak load reduction program was implemented in coordination with the Company's Massachusetts Grid Services Compensation Fund, increasing incentives for participating customers served by the targeted substations. (Referred to as the "ConnectedSolutions+" program.)

The Company also actively utilizes its 34-MWh stand-alone battery in Provincetown Massachusetts in a complex microgrid configuration able to supply up to 11,000 customers solely with the battery upon loss of traditional grid supply. This microgrid is currently operated with a dedicated microgrid control scheme. In the longer term, the Company plans to integrate operation of the Provincetown battery with a grid DERMS capability to coordinate dispatch of the Eversource battery with customer DER to cost-effectively increase the duration of the microgrid. Also in process is a project at the Company's Roosevelt solar facility to utilize DERMS to support voltage management use cases. The scope of the Roosevelt project incorporates investigation into lower-cost options for DER communication and control through a centralized grid DERMS. The Company is also planning to implement a ConnectedSolutions+ program in targeted locations in southeastern MA, an area with high solar penetration, for a managed EV charging use case to reduce the risk of reverse flow overloads by charging EV batteries during periods of high solar output.

b. The DERMS demonstration program is designed to implement multiple DERMS-dependent use cases in a targeted location to demonstrate the multiple benefits of different approaches, both independently and in coordination. The intent is to show the full potential of DERMS technology to inform efforts to deploy at scale across Connecticut. The Grid Services Compensation Fund is an important enabler of the DERMS demonstration, enabling the Company to increase incentives for DER customers supporting one or more use cases. For example, the Company would use the Grid Services Compensation Fund to provide incentives in exchange for a customer allowing use of an advanced inverter for a voltage management use case. Currently, the Company has no mechanism to compensate customers for this or any locally-targeted capacity or voltage use cases.

The DERMS demonstration could also incorporate the use of dynamic flexible interconnections. Using DERMS technology, a dynamic flexible interconnection allows larger-scale DER facilities an increased operating envelope (i.e., greater charge and discharge levels) based on real-time operating conditions. For example, a fixed operating envelope may restrict battery discharge to 25 percent of nameplate in Spring and Fall seasons when load is relatively low and solar output is high. A dynamic flexible interconnection could relax this restriction and allow more discharge based on real-time grid conditions (i.e., cloudy warm days when solar output is lower and load is higher.) The DERMS demonstration could incorporate the concept of dynamic flexible interconnection to show the incremental value of an expanded operating envelope for capacity and/or voltage related DERMS use cases

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman, Juan F. Martinez, Steven C. Osuch, Andrew C. Belden, Gerhard Walker and Warren R. Boutin
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 107-108, "Enable dynamic flexible interconnections to reduce costs of DER integrations)".

a. Please describe the status of developing a dynamic flexible interconnection program including when the Company expects to conduct its first demonstrations.
b. Has the Company evaluated using dynamic flexible interconnection as a way to defer to the proposed upgrades as part of the proposed Shared Hosting for Advancement of Renewable Energy (SHARE) Program?

Response:

a. Please refer to OCC-583, Attachment 1, for the Joint EDC's Proposal for Implementing Flexible Interconnections in CT. Specifically, refer to OCC-583 Attachment 1, at 13, for the joint EDC's plan for implementing Flexible Interconnections across both EDC service territories. Eversource's plan for enabling flexible interconnections in Connecticut was filed on March 16, 2026, in Docket No. 25-01-27, and at this time does not include dynamic flexible interconnections due to the need to first implement an ADMS system and a DERMS system.

b. The Company has not evaluated utilizing dynamic flexible interconnections as a way to defer the upgrades proposed for the SHARE program.

   Currently, the SHARE program and dynamic flexible interconnection target different needs for DER developers and the Company. The SHARE program is intended to target larger DER development in more rural areas where the available real estate for DER exceeds the load in the region. The Flexible Interconnection program is intended to target underutilized hosting capacity that cannot otherwise be utilized without dynamically controlling a distributed asset. The Company is considering "planned flexibility" as an option in the SHARE program where specific assumptions around curtailment with co-sited storage are taken into consideration in the solution design.

   Flexible interconnections would be offered as a vintaging queue, with a window where all applicants will evenly split the capacity made available by dynamic control of the assets.

This differs from the SHARE program where a window will be opened, and the group studied solution will factor all group study participants in aggregate and produce a solution that allows their project to operate at or near their intended capacity within the limitations of the upgrades we determine are feasible for the group study itself. These upgrade costs are then shared by the DER developers, avoiding the first to build funding future DER at that site.

The SHARE project site selection will consider a maximum distribution system benefit component, when plausible, which is why the Company shows capital project cost component for projects proposed in Exhibit CLP-TSP-3 at pages 146-149. The total project would be a net reduction for each stakeholder for distribution system needs and DER project funded needs.

Date Filed: September 21, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling, Elli Ntakou and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 68, "DERMS Demonstration – Demonstrate the value proposition of advanced DERMS capabilities, including (1) use of DER to increase system efficiency and reduce line losses; (2) integration of multiple types of DER in a microgrid application for critical load; and (3) investigation of lower cost approaches to communication and control of stand-alone solar and storage facilities integrated into the Company's centralized DERMS system."

a. Has the Company deployed DERMS and implemented any DERMS use cases to date?
b. Please describe how this DERMS demonstration will be coordinated with the implementation of the Grid Services Compensation Fund and Dynamic Flexible Interconnection.

Response:

a. Other than the use of its aggregator DERMS utilized for an ISO-New England system peak load reduction use case through the ConnectedSolutions program, the Company has not deployed DERMS or implemented DERMS use cases in its Connecticut service territory.

   In its western Massachusetts service territory, the Company deployed the first phase of a grid DERMS at the end of 2025 and is currently completing the second phase of the grid DERMS project with a target in-service date at the end of 2026. The Company is currently implementing foundational upgrades to its SCADA eECS and DMS systems in Eastern Massachusetts and is expecting to start a grid DERMS project there in early 2027.

   With respect to use cases, in western Massachusetts, the Company is currently utilizing its grid DERMS for weather-based operational forecasting, providing real time system operators with hour- and day-ahead visibility into the impact of DER on power flows, including the impact of solar generation on equipment loading. In eastern Massachusetts, the Company conducted its first locational demand response program in Summer 2026, utilizing its aggregator DERMS to reduce load during peak events at three substations in the Boston area with identified risk of overload. The Boston substation peak load reduction program was implemented in coordination with the Company's Massachusetts Grid

Services Compensation Fund, increasing incentives for participating customers served by the targeted substations. (Referred to as the "ConnectedSolutions+" program.)

The Company also actively utilizes its 34-MWh stand-alone battery in Provincetown Massachusetts in a complex microgrid configuration able to supply up to 11,000 customers solely with the battery upon loss of traditional grid supply. This microgrid is currently operated with a dedicated microgrid control scheme. In the longer term, the Company plans to integrate operation of the Provincetown battery with a grid DERMS capability to coordinate dispatch of the Eversource battery with customer DER to cost-effectively increase the duration of the microgrid. Also in process is a project at the Company's Roosevelt solar facility to utilize DERMS to support voltage management use cases. The scope of the Roosevelt project incorporates investigation into lower-cost options for DER communication and control through a centralized grid DERMS. The Company is also planning to implement a ConnectedSolutions+ program in targeted locations in southeastern MA, an area with high solar penetration, for a managed EV charging use case to reduce the risk of reverse flow overloads by charging EV batteries during periods of high solar output.

b. The DERMS demonstration program is designed to implement multiple DERMS-dependent use cases in a targeted location to demonstrate the multiple benefits of different approaches, both independently and in coordination. The intent is to show the full potential of DERMS technology to inform efforts to deploy at scale across Connecticut.

The Grid Services Compensation Fund is an important enabler of the DERMS demonstration, enabling the Company to increase incentives for DER customers supporting one or more use cases. For example, the Company would use the Grid Services Compensation Fund to provide incentives in exchange for a customer allowing use of an advanced inverter for a voltage management use case. Currently, the Company has no mechanism to compensate customers for this or any locally-targeted capacity or voltage use cases.

The DERMS demonstration could also incorporate the use of dynamic flexible interconnections. Using DERMS technology, a dynamic flexible interconnection allows larger-scale DER facilities an increased operating envelope (i.e., greater charge and discharge levels) based on real-time operating conditions. For example, a fixed operating envelope may restrict battery discharge to 25 percent of nameplate in Spring and Fall seasons when load is relatively low and solar output is high. A dynamic flexible interconnection could relax this restriction and allow more discharge based on real-time grid conditions (i.e., cloudy warm days when solar output is lower and load is higher.) The DERMS demonstration could incorporate the concept of dynamic flexible interconnection

to show the incremental value of an expanded operating envelope for capacity and/or voltage related DERMS use cases.

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling, Elli Ntakou and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 134, "The DERMS demonstration location will be determined based on further study; preliminary assessment indicates the potential of coordinating with other programs planned at Triangle, Frybrook, and Campville."

a. Please describe the "other programs" planned at Triangle.
b. Please confirm the other programs planned at Frybrook, and Campville are the NWA projects. If not, please describe the other programs planned.

Response:

a. Triangle substation was identified as an opportunity for a DERMS demonstration due to the following conditions:
    1) A large BESS DER is in the queue at this substation
    2) This substation has undergone recent upgrades and has switchgear and relays suitable for use by a DERMS system without this incremental expense
    3) This substation is experiencing an overload that currently requires mitigation during peak load events, creating an opportunity to study the efficacy of using DERMS, in coordination with the Grid Services Compensation Fund, to mitigate or defer more costly solutions at the substation

.

b. The projects at Frybrook and Campville are the same projects the Company has identified in testimony as opportunities for Non-Wires Alternatives (NWAs) and are driven by forecasted overloads as well as reliability concerns. To date these projects have received initial funding in the capital plan but have not yet undergone detailed NWA engineering analysis.

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling, Elli Ntakou and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 134, "Advancing the Grid, Overview."

a. Please provide a line budget breaking down the proposed costs annually and in total across the "Advancing the Grid" program by asset health, communications, grid operations technology, planning analytics, sensors and SHARE.
b. Please also provide a line-item budget breakdown for the grid operations technology category.

Response:

a. Please refer to OCC-586, Attachment 1, for the requested information.
b. Please refer to OCC-586, Attachment 1, for the requested information.

Date Filed: September 22, 2026

Witness: David L. Gladey, Lavelle Freeman, John P. Dipaola-Tromba, Jennifer A. Schilling, Elli Ntakou and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 138, "Advancing the Grid, Planning Analytics - Advanced Forecasting Tools."

a. Please describe the milestones and timelines to integrate this tool into distribution planning if approved.
b. Please explain why existing forecasting tools cannot generate forecasted 8760 load shapes across all levels: substation, transformer, and at circuit levels

Response:

a. Based on the Company's experience, the procurement and deployment process will take 12-18 months from approval, and an addition 6 months to get the tools into full production.

b. Historically, time-series profile forecasts were not necessary to review capital projects and the single system peak was the most reliable forecast that could be produced. This is still valid today as the key input to capacity planning remains the magnitude of the peak, regardless of its time or date.

As iterated in the Company's responses to 21-05-15RE03 IDSP, there are also critical questions on the validity and cost benefit of creating an 8760 forecast as an 8760 forecast, by its very nature, not only forecasts the peak load and time of that peak load, but also the weather and load over the entire year.

While such profiles are useful for evaluating and sizing certain solutions (e.g., battery storage as an NWA, for which the Company can and does create 24-hour load profiles) they do not provide any incremental value for determining the scope of a substation project, and incur not insignificant incremental effort both on a technology and labor side. The Company has therefore not undertaken the full effort of creating such profiles given the incremental resources needed.

The existing tools the Company has in place were never designed nor intended to produce 8760 forecasts. This does not represent an insurmountable barrier but requires additional investments as the Company outlined in its comments to 21-05-15RE03 IDSP, which,

without there being any documented proof in either proceeding that 8760 forecasts would quantifiably benefit the customer in a manner offsetting additional costs, requires the Authority to lay out cost recovery pathways for such efforts.

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman, Gerhard Walker, and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-TSP-3, Page 29, Eversource shares that the "*greatest large DER potential is in rural areas where native load is light (Eastern, Northern and Northwest)*."

a. Please provide your forecasted solar capacity by region over the 10-year forecast period (2026-2035).

Response:

a. In reference to the slide Exhibit CLP-TSP-3, Page 29 the Company is interpreting the request to ask about the forecasted system capacity available for solar to interconnect in the regions outlined (Eastern, Northern and Northwest). The Company currently has a constraint in its system capacity to interconnect any more solar in those regions (Exhibit CLP-TSP-3, Page 145), not a forecasted issue. Without the SHARE proposal, DER customer are obligated to pay for the upgrades while projects at a later point in the queue would be the beneficiary of such investments effectively stalling solar development. Please refer to OCC-588, Attachment 1, for the Company's solar forecast data. These values are incremental to the base year (2025). However, it must be noted that the solar forecasts created by the Company are "infrastructure constraint", meaning they consider the cost to upgrade as they prioritize regions to forecast solar into. Therefore, these values are not indicative of a future adoption under SHARE, where those costs would be mitigated. The Company would develop these updated forecasts at such time when costs and cost allocation under SHARE are known.

Date Filed: September 22, 2026

Witness: Lavelle A. Freeman, Gerhard Walker and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

In Exhibit CLP-TSP-3, Page 87, Eversource indicates that it uses top-down forecasting for electric vehicle, solar, and energy efficiency adoption for its 10-year distribution planning horizon, and bottom-up forecasting for electric vehicle, solar, and energy efficiency adoption for its long-term demand assessment.

a. Please identify what specific legislation or state policy objectives, if any, informed your forecast for the distribution planning horizon and what specific legislation or state policy objectives, if any, informed your forecast for the long-term demand assessment.
b. Please explain your rationale for using a top-down forecast for the distribution planning assessment, and a bottom-up forecast for the long-term demand assessment.
c. Please identify what data is included in the "Socio – Economic Modelling based on Customer Reference Classes" referenced for the bottom-up forecast for the long-term demand assessment.
d. Please provide the following from your top-down forecast:
    i. Annual forecasted electric vehicle adoption from 2027-2036, by region
    ii. Forecasted impact on peak from electric vehicle adoption from 2027-2036, by region
    iii. Forecasted impact on peak from energy efficiency from 2027-2036, by region
    iv. Forecasted impact on peak from solar adoption from 2027-2037, by region

Response:

The two referenced processes for the 10-year forecast and the Long-Term Demand Assessment (LTDA) are fundamentally different as they serve a different purpose – the 10-year forecast's objective is to provide the Company with an outlook on system needs that are firm enough that the Company can make capital decisions based on this forecast. The LTDA does not trigger capital projects and can include a wide array of scenarios and assumptions around policies, technologies, adoptions, and programs which might be implemented and serves as a tool to evaluate such approaches. It also helps the Company understand how to ensure that a proposed project triggered within the 10-year horizon is developed in a manner that supports the Company's ability to accommodate a long-term need. As a result, the nature of the inputs to both forecast processes vary.

a. While there are legislatively mandated goals to generally reduce statewide emissions, the only adoption-specific goal used to inform the Company's forecast is the GC3 projected pathway of converting 20% of light-duty vehicles to EVs by 2030 as discussed in the 2020 EV Roadmap for Connecticut. There were no state goals imposed by Connecticut for solar or heat pump adoption. Here the Company utilizes inputs from the New England ISO as well as installation and queue data for the system-wide forecast. The system-wide adoption is then allocated locally. For example, ground-mounted solar is allocated using propensity models for all of the parcels in the state to sustain large scale solar development.

b. The graphic referenced in Exhibit CLP-TSP-3, Page 87 shows the Company using both bottom up and top-down methodologies in both approaches with the top-down component typically determining statewide adoption or targets and the bottom-up allocating those values geographically.

c. When developing LTDA scenarios, the Company can allocate components such as electric vehicles to substation regions by customers serviced using customer reference classes. This allows the Company to "cluster" all customers into one of a handful of reference classes, each reference class having different adoption targets in % by a certain year. As a result, any statewide numbers would then be allocated to stations depending on the reference class make up of their customer base. The reference classes can be created utilizing socio-economic factors such as income, home ownership, or other factors.

d. Please refer to OCC-589, Attachment 1, for the requested data, where regions include eastern, central, and western Connecticut. These values are all incremental to the base year (2025).