STATE OF CONNECTICUT
PUBLIC UTILITIES REGULATORY AUTHORITY

APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY D/B/A EVERSOURCE ENERGY TO AMEND ITS RATE SCHEDULES	:	DOCKET NO. 26-05-10
	:	OCTOBER 21, 2026

PREFILED DIRECT TESTIMONY OF CHRISTOPHER LITTLE CHIEF OPERATING OFFICER, ECOS ENERGY LLC

ON BEHALF OF ALLCO FINANCE LIMITED

Subject: the Company's requested return on common equity

TABLE OF CONTENTS

I. Introduction and Qualifications
II. Purpose, Summary, and Reservation
III. The Company's Request and What It Costs Customers
IV. What the Company's Own Securities Say About Its Cost of Capital
V. The Circularity of Authorized Returns
VI. The Company's Affiliates and Its Risk
VII. Recommendation
VIII. Conclusion
Exhibits CL-1 through CL-8

I. INTRODUCTION AND QUALIFICATIONS

Q1. Please state your name, position, and business address.

A. My name is Christopher Little. I am the Chief Operating Officer of Ecos Energy LLC ("Ecos"). My business address is 80 South 8th Street, Suite 900, Minneapolis, Minnesota 55402.

Q2. Please describe Ecos and its relationship to Allco Finance Limited.

A. Ecos develops, finances, builds, and operates solar generating facilities in New England and elsewhere. Ecos is an affiliate of Allco Finance Limited ("Allco"), the intervenor in this proceeding. Ecos is the Seller under renewable energy credit contracts and power purchase agreements with The Connecticut Light and Power Company ("CL&P" or the "Company"), and an interconnection customer of the Company.

Q3. Please summarize your professional background.

A. I hold a Bachelor of Business Administration in Real Estate and Urban Land Economics from the University of Wisconsin–Madison (1999). From 1999 to 2005 I was a right-of-way agent for We Energies, the Wisconsin electric and gas utility, where I acquired right-of-way and secured the land-use entitlements and permits for substations, gas regulator stations, and communication towers. From 2005 to 2008 I worked in land brokerage at Colliers Turley Martin Tucker and then as Land Acquisition Manager for Ryland Homes, acquiring land for new residential construction. I joined Ecos in 2008. From April 2021 to January 2024 I was Vice President and Senior Relationship Manager at The Huntington National Bank, where I originated and underwrote financings of solar generating projects structured as sale-leasebacks. I returned to Ecos in 2024 and serve as its Chief Operating Officer.

At Ecos I am responsible for the company's solar development and operating activities: business development, land acquisition, land-use entitlement and permitting, equipment procurement, construction, project financing, and the operation and performance reporting of the operating fleet. Since 2010 I have been directly involved in the development, financing, construction, and operation of each of the 52 distributed generation ("DG") solar facilities Ecos has placed in service, totaling approximately 75 MW (AC) — more than 100 MW (DC) — in seven states: Connecticut, Massachusetts, Vermont, Indiana, Minnesota, Georgia, and California. Twenty-three of those facilities, totaling approximately 27 MW (AC), are in Connecticut, and twenty of them are interconnected to CL&P. I continue to oversee the day-to-day operation of all 52 facilities. I also acquired, on behalf of Ecos and its affiliates, the real estate on which those facilities are built and the land Ecos holds for future development.

Project financing has been a principal part of my work. I have led the tax-equity financing, structured as sale-leasebacks, of 38 of Ecos's solar projects, and I have been responsible for the debt and equity raised for the balance of the portfolio. That work consists of negotiating with lenders and tax-equity investors over the returns they require and the terms on which they will commit capital, and of evaluating the credit and cost of capital of the utility counterparties whose contracts support our projects' revenues. For the three years I spent at Huntington, I sat on the other side of those negotiations, pricing and underwriting the returns an institutional investor required to finance solar generating assets.

Q4. Have you previously testified before this Authority or other regulatory bodies?

A. I have not previously testified before this Authority. I have previously testified before the Vermont Public Utility Commission.

II. PURPOSE, SUMMARY, AND RESERVATION

Q5. What is the purpose of your testimony?

A. My testimony addresses the Company's request for a return on common equity of 10.25 percent. I am not a cost-of-capital modeler and I do not sponsor a discounted-cash-flow or capital-asset-pricing study. I testify as a participant in the market for capital for energy assets — someone who raises money for projects whose revenues depend on this Company's credit — and I present three kinds of evidence that are available without a model: what the Company's own traded securities say about the return investors actually require of it; what the Company has told this Authority about its ability to raise capital; and what the Company's affiliates are authorized to earn. I then explain why the method the Company's witness uses to justify 10.25 percent — comparison to returns other commissions have authorized — is circular, drawing on an analysis published by Synapse Energy Economics in January 2026 that I have reviewed.

Q6. Does this testimony address the other subjects on which Allco has conducted discovery in this docket?

A. Not yet. Allco has served interrogatories on the Company's interconnection cost-estimating, overhead-loader, final-accounting, customer-funds, load-settlement, and queue practices, and on the executive compensation and agreements that drive part of the revenue requirement. Many of those responses are incomplete, have been answered by cross-reference, or are the subject of pending motions to compel and extension requests. I expect to supplement this testimony to address those subjects, with recommendations, once the Company has provided complete answers, and Allco reserves the right to do so under the Authority's schedule.

Q7. Please summarize your conclusions.

A. First, the Company's request is expensive and unnecessary. The increase from the currently authorized 9.25 percent to 10.25 percent adds, by the Company's own calculation, $38.3 million of after-tax equity return in the Test Year rising to $49.3 million in Rate Year 4, plus $14.5 million to $18.7 million of income-tax gross-up — roughly $53 million to $68 million a year attributable solely to the one-point increase on existing rate base. The Company does not contend that it has been unable to attract capital at the authorized return; it says it "does not contend that it has failed to attract capital," (ALLCO-054) and it plans to issue $1.45 billion of first mortgage bonds between July 2026 and June 2028 whether or not the increase is granted.

Second, the Company's own securities show that investors require less than 10.25 percent to hold them. The Company's most recent first mortgage bond was issued at a yield of 4.98 percent, and its longest outstanding bonds trade at about 6.4 percent (ALLCO-143, Attachments 1 and 2). The Company's cumulative preferred stock — the $3.24 Series G, which trades over the counter — yields approximately 6.1 percent at its recent price of $52.81. The parent's common stock yields approximately 4.8 percent in dividends and trades at about 1.5 times book value. Put another way, the 9.25 percent return the Company is currently authorized to earn on book equity, divided by the roughly 1.5 price-to-book ratio, is an earnings yield of approximately 6.1 percent on the price investors actually pay for the stock. These are prices investors pay with their own money; they are the only direct evidence in this record of the return investors actually require of this Company, and the Company's witness did not analyze any of them.

Third, the comparison to returns authorized elsewhere, on which the Company's request principally rests, is circular: each commission looks to what the others have authorized, and the result is an authorized return that has not fallen even as the market cost of equity has. A return set by that method is not a measure of the Company's risk; it is a measure of other commissions' decisions.

Fourth, the Company's affiliates earn 9.50 percent (Public Service Company of New Hampshire) and 9.80 percent (NSTAR Electric) under mechanisms the Company itself describes as sharing earnings with customers, and the Company has produced no analysis showing that CL&P is riskier than they are.

I recommend that the Authority deny the requested increase and set the return on common equity at no more than the currently authorized 9.25 percent, and that it direct the Company to file, with any future request, an analysis of the yields on its own traded securities and of the market-to-book ratio of its parent's common stock.

III. THE COMPANY'S REQUEST AND WHAT IT COSTS CUSTOMERS

Q8. What return on equity does the Company request, and what is it currently authorized to earn?

A. The Company requests 10.25 percent. Its currently authorized return is 9.25 percent. The Company's response to ALLCO-054, Attachment 1 (Exhibit CL-1), quantifies the difference: $38.3 million of after-tax equity return in the Test Year, rising to $49.3 million by Rate Year 4, plus income-tax gross-up of $14.5 million to $18.7 million. Those amounts are the cost of the one-point increase alone, on existing rate base; they do not include the return on the capital additions the Company proposes.

Q9. Has the Company shown that it cannot attract capital at 9.25 percent?

A. No. Asked that question directly, the Company answered that it "does not contend that it has failed to attract capital." It reframed the question as whether it can raise capital "on reasonable terms in all market conditions," and warned that at a lower return it "would have no choice but to reconsider its capital" plans. ALLCO-054 (Exhibit CL-1). At the same time, in ALLCO-051 (Exhibit CL-7), it disclosed a plan to issue $1.45 billion of first mortgage bonds between July 2026 and June 2028, a capital structure of about 54 to 55 percent equity that it maintained in order to preserve its credit ratings, and approximately $400 million of retained equity. A company that is issuing long-term debt on schedule, retaining earnings, and holding more equity than it proposes for ratemaking is not a company that the capital markets have closed to.

Q10. Did the Company's return-on-equity witness analyze the Company's own securities?

A. No. Asked in ALLCO-100 (Exhibit CL-4) whether the witness had analyzed the market yields on the Company's own preferred stock or first mortgage bonds, the Company answered that no such analysis had been performed. Asked in ALLCO-138 (Exhibit CL-3) to compute the cost of equity implied by the parent's market-to-book ratio, the Company said the calculation was "not available."

IV. WHAT THE COMPANY'S OWN SECURITIES SAY ABOUT ITS COST OF CAPITAL

Q11. Why do you look to the Company's own securities?

A. Because they are the one place where investors, with their own money, tell us what return they require of this Company. A proxy group is an estimate of what investors might

require of companies like CL&P; the price of CL&P's own preferred stock is what they actually require of CL&P. When I negotiate with a lender or a tax-equity investor, the return they demand is set by the market for comparable risk, not by a survey of what other investors were promised elsewhere.

Q12. What do the Company's preferred shares show?

A. CL&P has several series of cumulative preferred stock outstanding, totaling $116.2 million at par (RRU-072, Attachment 3), of which the $3.24 Series G (ticker CNLPL) trades with some regularity over the counter. On August 12, 2026, the most recent trade reported by the quotation service I consulted, the $3.24 Series G closed at $52.81, a current yield of 6.1 percent. [Exhibit CL-6.] Preferred stock ranks ahead of common equity, so its yield is a floor on the return required of common equity only in the sense that common must earn more — but the difference is a matter of the incremental risk of the common, and nothing in the Company's filing explains why that increment should be more than four percentage points for a regulated distribution company with decoupling, capital trackers, and storm-cost recovery. The Company was asked in ALLCO-100(c) to confirm the accuracy of these market figures or to state its own; it has not done so.

Q13. What does the parent's common stock show?

A. Eversource Energy's common stock yields approximately 4.8 percent in dividends at its current price (an annualized dividend of $3.15 on a price of $65.44 at October 20, 2026), and it trades at about 1.5 times its book value (Exhibit CL-6). I do not build a growth assumption on top of those figures; a forecast growth rate is a projection, not a market observation, and the question before the Authority is what return investors actually require, which the prices themselves answer. Two observations follow from the prices alone. First,

investors accept a 4.8 percent current yield on the parent's common stock — an enterprise that carries activities and obligations CL&P does not have — which is below the yield on CL&P's own preferred stock and in line with the yield on its secured bonds. Second, as explained in Q15, a price well above book value means investors are paying a premium for the authorized return the Company already earns, which they would not do if that return were below what they require.

Q14. What do the Company's bonds show?

A. CL&P's most recent first mortgage bond — the 2025 Series A, $400 million at a 4.95 percent coupon, issued January 13, 2025 and due 2030 — was priced at a yield of 4.981 percent, 55 basis points over the benchmark Treasury, at ratings of A1/A/A+ (ALLCO-143, Attachment 1). As of October 2, 2026, the Company's fifteen outstanding first mortgage bond series traded at market yields between 4.56 and 6.49 percent, with its thirty-year 2023 Series A at 6.42 percent, at spreads of 0.37 to 1.21 percentage points over Treasuries (ALLCO-143, Attachment 2). The Company itself estimates that a downgrade from the A category to BBB would raise its cost of debt by only about 0.25 percent (ALLCO-143(c)). A utility whose secured debt was last issued at 4.98 percent, and whose longest bonds trade at about 6.4 percent, is asking this Authority to find that its equity investors require 5.3 percentage points more than its new-issue debt and 3.8 points more than its thirty-year bonds. That spread is wider than the increment investors actually receive on the Company's own preferred stock over its bonds.

Q15. Does the market-to-book ratio tell the Authority anything?

A. Yes. If a utility's authorized return equals its cost of equity, its stock should trade at approximately book value. Eversource's common stock trades at approximately 1.5 times

book value (price-to-book of 1.52 at October 21, 2026; Exhibit CL-6). A premium to book means investors are paying more than a dollar for a dollar of equity that earns the authorized return — which is only rational if the return they require is lower than the return being authorized. The Company declined to perform this calculation (ALLCO-138(d)).

V. THE CIRCULARITY OF AUTHORIZED RETURNS

Q16. On what does the Company principally rely to justify 10.25 percent?

A. On the returns other commissions have authorized for other utilities, presented as the range within which a "comparable" return must fall. That is the approach the Company's witness takes in this docket and in the affiliates' cases.

Q17. What is the problem with that approach?

A. It is circular. In January 2026, Synapse Energy Economics published an analysis titled "Utility Returns on Equity: A Self-Fulfilling Prophecy?" (Exhibit CL-5), which I have reviewed and whose reasoning I adopt. Its author observes that utilities cite other commissions' authorized returns to justify their own, that commissions anchor to one another's decisions, and that "the result is a self-fulfilling prophecy" in which "lost … is the fundamental question that should inform the ROE: What is the riskiness of this utility investment?" The comparable-return argument, as utilities present it, "shuts the door to the possibility of a lower ROE" and "locks customers into the ROEs they have been paying." The analysis notes research from the University of California, Berkeley's Energy Institute estimating that returns in excess of the cost of equity cost consumers about $7 billion a year, and that commissions have tended not to let returns fall below 10 percent — a threshold the author calls "ultimately arbitrary." It also makes a legal point that I think is right: the Supreme Court's standard in Bluefield and Hope refers to returns earned by "other

enterprises having corresponding risks," and most enterprises of corresponding risk have no authorized return at all. Comparing authorized returns to authorized returns does not answer the question the standard asks.

Q18. Does the Synapse analysis offer an example?

A. Yes. In San Diego Gas & Electric's 2025 cost-of-capital case, the utility requested 11.25 percent; Synapse's witness calculated a market cost of equity of 8.87 percent, and other intervenors calculated similar or lower figures; the utility's prior authorized return was 10.23 percent; and the California commission approved 9.93 percent — above the national average of about 9.7 percent, but a decrease. The point is not that 9.93 percent is the right number for Connecticut. The point is that when a commission asked what investors actually require rather than what other commissions had authorized, the answer was well below the utility's request.

Q19. How does this apply to the Company's request?

A. The Company asks for an increase of a full percentage point, to 10.25 percent, at a time when the national average of authorized returns is about 9.7 percent, when its own preferred stock yields about 6.1 percent, its new-issue debt 4.98 percent and its longest bonds about 6.4 percent, when its parent's common stock yields 4.8 percent and trades at 1.5 times book, and when it concedes it has had no difficulty attracting capital at 9.25 percent. The only way to reach 10.25 percent is to look away from the Company and toward other commissions' decisions. The Authority is not bound by those decisions, and the evidence specific to this Company points the other way.

VI. THE COMPANY'S AFFILIATES AND ITS RISK

Q20. What returns do the Company's affiliates earn?

A. Public Service Company of New Hampshire earns 9.50 percent on a 50.00 percent equity ratio (New Hampshire DE 24-070, July 25, 2025), and NSTAR Electric earns 9.80 percent on a 53.21 percent equity ratio (Massachusetts D.P.U. 22-22, November 30, 2022), each with storm funds, earnings-sharing mechanisms, and, in NSTAR Electric's case, decoupling and eight capital trackers. ALLCO-048 (Exhibit CL-2). The Company disputes that those mechanisms reduce risk, but it describes the earnings-sharing mechanisms as operating "on an asymmetric basis" and, in its experience, "in a one-sided manner — to the benefit of customers," which is another way of saying that they cap the upside while customers bear the downside. The Company has produced no analysis comparing CL&P's risk to its affiliates', and nothing in its filing or its response to ALLCO-048 indicates that the Company's witness considered the affiliates' authorized returns; Allco's follow-up on that point, ALLCO-158, is pending.

Q21. Is CL&P riskier than its affiliates?

A. I have seen nothing in this record to suggest so. CL&P is a distribution-only utility in a state with storm-cost recovery, a revenue adjustment mechanism, and a multi-year rate plan proposed in this very docket. Its parent is the same, its service company is the same, and its credit is supported by the same consolidated enterprise. A request that CL&P be authorized 45 to 75 basis points more than its sister companies, with no risk analysis to support the difference, should be denied on that ground alone.

VII. RECOMMENDATION

Q22. What do you recommend?

A. That the Authority (1) deny the requested increase and set the return on common equity at no more than the currently authorized 9.25 percent; (2) in weighing the Company's proxy-group evidence, give controlling weight to the market evidence specific to this Company — the yields on its own preferred stock and debt and the market price of its parent's common stock relative to book value — and require the Company to file that evidence with any future return-on-equity request; (3) take notice that the Company has conceded it has not failed to attract capital at the current return; and (4) reserve, as I do, the question whether the quality of the Company's interconnection and renewable-program service warrants a further adjustment, to be addressed in supplemental testimony when the Company's discovery responses are complete.

Q23. Have you quantified the effect of your recommendation?

A. Yes, by reference to the Company's own numbers. Denying the increase avoids $38.3 million to $49.3 million a year of after-tax equity return and $14.5 million to $18.7 million a year of associated income tax — approximately $53 million to $68 million a year — on existing rate base alone (Exhibit CL-1).

VIII. CONCLUSION

Q24. Does this conclude your testimony?

A. Yes, subject to the supplement described in Section II.

EXHIBITS

CL-1 CL&P Response to ALLCO-054 and Attachment 1 (revenue-requirement effect of 10.25% vs. 9.25%)
CL-2 CL&P Response to ALLCO-048 and Attachment 1 (affiliate authorized returns and mechanisms)

CL-3 CL&P Response to ALLCO-138 (market-to-book calculation declined)
CL-4 CL&P Response to ALLCO-100 (no analysis of the Company's own securities)
CL-5 Synapse Energy Economics, "Utility Returns on Equity: A Self-Fulfilling Prophecy?" (M. Bandyk, Jan. 14, 2026)
CL-6 Market data: CL&P $3.24 Series G preferred price and yield (Aug. 12, 2026 quotation); Eversource Energy common price, dividend yield and price-to-book (Oct. 20–21, 2026); CL&P first mortgage bond issuance yields and October 2, 2026 market yields (ALLCO-143, Attachments 1 and 2)
CL-7 CL&P Response to ALLCO-051 (capital structure; planned first mortgage bond issuance; retained equity)
CL-8 Resume of Christopher Little

Exhibits CL-1 through CL-8 to the Prefiled Direct Testimony of Christopher Little — Index

Exhibit CL-1 — CL&P Response to ALLCO-054 and Attachment 1 (compiled pages 2–30)

Exhibit CL-2 — CL&P Response to ALLCO-048 and Attachment 1 (compiled pages 31–34)

Exhibit CL-3 — CL&P Response to ALLCO-138 (compiled pages 35–37)

Exhibit CL-4 — CL&P Response to ALLCO-100 (compiled pages 38–39)

Exhibit CL-5 — Synapse Energy Economics, “Utility Returns on Equity: A Self-Fulfilling Prophecy?” (compiled pages 40–41)

Exhibit CL-6 — Market Data on the Company’s and Its Parent’s Securities (compiled pages 42–51)

Exhibit CL-7 — CL&P Response to ALLCO-051 (compiled pages 52–56)

Exhibit CL-8 — Resume of Christopher M. Little (compiled pages 57–59)

Each exhibit is preceded by a slip sheet and bears the exhibit label and page number in its lower right corner.

Exhibit CL-1

CL&P Response to ALLCO-054 and Attachment 1

Revenue-requirement effect of the requested 10.25% ROE compared with 9.25%;
the Company's statement that it "does not contend that it has failed to attract capital" (ALLCO-054(b))

Date Filed: September 22, 2026

Witness: Douglas P. Horton, Brendan J. O' Brien and Garrett J. Murray
Request from: ALLCO

Question:

With respect to the requested 10.25% return on common equity and the Company's currently authorized distribution return on common equity of 9.25% established in Docket No. 17-10-46 (or such other return as the Company contends is currently authorized):

a. quantify, for the Rate Year and each subsequent year of the proposed PBMRP term, the portion of the proposed revenue requirement increase that is attributable solely to applying the requested return on common equity, rather than the currently authorized return, to rate base in service as of the date certain (December 31, 2025) — stating separately the return component and the associated income tax gross-up, and producing the calculation in native (Excel) format;
b. state whether the Company contends that the currently authorized return has failed to attract capital to the Company, and, if so, identify each specific instance — each debt or equity offering, credit rating action, capital program deferral, or financing the Company contends was impaired, cancelled, downsized, or made more expensive because of the currently authorized return — and produce every analysis or document supporting each such contention;
c. state whether any incremental capital the Company plans to invest during the proposed PBMRP term would not be invested if the currently authorized return on common equity remained in effect, identifying each affected project or program and producing every analysis supporting that identification;
d. explain why the Company's proposed cost of long-term debt reflects the embedded (historical) cost of debt issued in prior years (4.81%, Schedule D-1.0) while its proposed return on common equity reprices the entire common equity balance — including equity supporting plant placed in service years or decades ago — to a claimed current market rate, and state whether the Company performed or considered any analysis in which only incremental common equity is priced at the requested return while previously committed equity continues at the currently authorized return, producing any such analysis; and
e. if the Company contends that investors' opportunity cost requires repricing all equity to a current market rate, reconcile that contention with the Company's use of embedded cost for debt investors whose opportunity cost has likewise changed, and with the market yields on the Company's own outstanding securities addressed in Q-ALLCO-052.

Response:

a. Please refer to ALLCO-054, Attachment 1. The Company notes that it is currently earning below its authorized return on equity of 9.25 percent.

b. The Company does not contend that it has failed to attract capital, nor does it contend that the prospect of attracting capital is a simple yes-or-no question. The question is at what cost can the Company attract capital on reasonable terms in all market conditions in order to appropriately balance affordability with safe and reliable electric system operations for customers.

c. For any regulatory framework to be a successful, sustainable solution, it must balance (1) the reliability and performance requirements of the Company's customers and the broader State of Connecticut; (2) customer rate stability and affordability; (3) incentives for cost efficiency in utility operations; and (4) implementation of a revenue support mechanism sufficient to cover the cost of delivering these objectives to customers, including the cost of capital. That means the whole solution, including the sufficiency of going-in revenue requirements to cover the utility's costs as well as subsequent revenues to support incremental investment, must operate cohesively.

   As stated in the Company's response to OCC-423[i], OCC-522[ii], and EOE-156[iii], in order to avoid a cycle of sequential rate cases as frequently as possible, the Company must operate in a regulatory framework that provides an allowance of revenues sufficient to cover its cost of service to customers, including its cost of capital. This is an important criterion not only for utility equity investors but bondholders as well. Moody's, for example, has a section in its ratings criteria plainly titled "Sufficiency of Rates and Returns," in which it describes how varying degrees of ability to earn a reasonable return is evaluated in the context of credit worthiness. To the extent the result of this docket is one in which the above objectives are not adequately balanced, specifically if revenues are insufficient to cover the cost of service during the Rate Year and beyond, the Company would have no choice but to reconsider its capital investment forecast with consideration given to the frequency and cadence of base rate case filings.

d. As a general practice, the Company does not refinance long-term debt prior to maturity due to costly make-whole provisions. Consequently, with respect to the cost to the Company for issuances of First Mortgage Bonds, the Company's current credit ratings apply to new (prospective) issuances only. Therefore, the Company's current risk profile, as viewed by rating agencies and the investment community, does not impact the cost of the Company's entire balance of debt outstanding at a point in time. The Company's entire balance of equity supports its current financial position, including its overall riskiness. Therefore, consistent with this premise and PURA practice for calculating the cost of capital for use

in ratemaking, the Company establishes the weighted average cost of debt based on known/issued debt and the cost of equity based on the balance of equity supporting rate base.

e. As stated above, the Company does not refinance long-term debt prior to maturity due to costly make-whole provisions. The cost *to the Company* on its outstanding debt is the interest expense as well as amortization of any premium or discount determined at the time of each issuance that persist until each matures, regardless of how any individual security may continue to trade on secondary markets. This is the cost that is reflected in the Company's rates and paid for by its customers. Moreover, the ongoing and substantial capital investment necessary to achieve the objectives outlined above require a financially-stable, effectively-managed utility that makes prudent decisions throughout its operations, including how it secures the funding to perform those investments. Even if the Company were able to refinance its entire balance of outstanding long-term debt at a single point in time the entire balance of new debt would be subject to prevailing interest rates at the time of issuance, introducing considerable uncertainty and, at present, higher cost of service.

Prior Referenced Responses:

[i] OCC-423 Question:

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

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

OCC-423 Response:

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

To cover the issues raised in the question, the Company's response is organized as follows:
1. Review of relevant aspects of the Company's PBMRP.

2. Considerations on the design of capital-driven revenue support.
3. Specific responses to parts (a), (b) and (c), above.

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

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

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

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

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

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

- A going-in revenue requirement that reasonably reflects the Company's actual operating expenses and cost of investment in the Rate Year, so that through effective management and prudent decision making, the Company can achieve the true efficiency gains that will be needed to stretch the approved revenue requirement over the stay-out term. Without a reasonable opportunity to maintain financial integrity over a stay-out period, as measured by the authorized ROE, the utility cannot focus on innovation and efficiency gains – and will instead file for the next rate case to make up ground. To accomplish this goal, the overall paradigm must "hang" together, making the base revenue requirement a pivotal element. The many components of a PBR plan, including going-in rates, as well as the subsequent rate adjustments, must work in concert with performance objectives and the capital investment requirements expected of the Company – for the benefit of customers, i.e., the entire framework must work to the benefit of customers, not only in relation to the price they will pay, but also in relation to supporting the level of service that they need and expect.

- Revenue support for incremental capital investment to support long-term system goals. The Company operates in a capital-intensive industry and has a substantial need to acquire cash on a systematic basis to operate its business. As annual capital investments regularly exceed net cash from operations (i.e. cash receipts from customers net of operating cash outflows), the Company must look to other capital sources to fund those investments. Those sources are the debt and equity investors supplying the cash to capital markets. This means the Company must compete with all other entities participating in those markets to attract capital. It is simply not possible for the Company to go to those markets and demand cash for free, or at below-market rates relative to the investor's risk when other entities participating in the same capital markets offer compensation for the use of funds over time.

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

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

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

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

2. Considerations on the Design of Capital Driven Revenue Support

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

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

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

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

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

Constructive features of PURA's RE01-PFD:

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

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

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

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

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

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

Revenue decoupling is a factor to consider here because the revenue decoupling mechanism ("RDM") subsumes all sales growth to the extent that it is occurring, funneling incremental sales revenues back to customers. RDM is supported by valid policy reasons; however, the fact is that there are capital costs associated with adding new customers. Historically, when consistent and steady levels in the range of ~3$ per year of annual growth in sales and revenues was available to a utility to help offset the cost of

incremental capital additions between rate cases, the pressing need for incremental revenue support was mitigated. Without the ability to capture that sales growth, and combined with the absence of an ongoing revenue support mechanism such as an F Factor taking effect on Month 1 of Rate Year 1, the Company would not be in a position to commit to a stay-out of any duration. This is because the Company would never be in a position to cover its cost of service (inclusive of its authorized cost of capital) because its rates would be set on a historical level of plant additions, despite the fact that its capital expenditures are higher than historical levels of depreciation, and because revenue decoupling ensures that even if load growth exists (and even if such load growth is enabled by the Company's increased level of capital expenditures) the Company is unable to retain additional revenues contributed by new customers, or new load.

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

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

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

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

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

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

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

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

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

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

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

Moreover, even if the Company were somehow able to find such remarkable cost savings, the going-in revenue requirement of the subsequent multi-year rate plan would capture those cost savings. Assuming continuation of the same PBR framework and required system investment, the Company would again be in the position of having to find an additional 34% of O&M savings (i.e. more than 60% cumulatively from Rate Year 1) in order to sustain itself over the next PBR term. Clearly, a framework that does not provide revenue supporting the full cost of incremental investment over a four-year period, as well as the next four-year period, is not a plausible or lasting framework. Thus, exclusion of the cost of capital from a capital support mechanism in an environment in which significant increases in capital investments are expected all but ensures the Company has no realistic opportunity to survive the PBR term without a critical need for a rate case to realign costs and rates. Consequently, the overall framework as outlined in the REO1-PFD had no practical chance of sustaining the Company financially for the four-year term,

nor would the Company have been able to even agree to a stay-out.

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

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

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

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

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

($ Millions)

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

16	Cumulative Depreciable Base	$700	$1,400	x 3.6% Depreciation	$25.2	$50.4
17	Cumulative Rate Base	$700	$1,400	x 9.8% Cost of Capital	$68.6	$137.2
18				Total Revenue Requirement	$93.8	$187.6
18				Error	-$10.8	-$21.6

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

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

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

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

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

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

additions in 2027, would be actually incorporated into rate base at that point. Following PURA's determination that the Company's actual plant additions are prudent, used and useful, the Company's rate base would be adjusted and associated revenue requirement allowed for recovery that would be limited to the lesser of:

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

2. The total revenue requirement for the actual plant in service.

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

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

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

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

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

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

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

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

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

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

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

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

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

Therefore, in 2022, the MDPU instituted the K-Bar providing an allowance for system infrastructure

projects, coupled with reporting requirements on investment levels. The MDPU maintained the I-X formula to cover the O&M portion of the approved revenue requirement, which is what the Company is proposing in this case.

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

[ii] OCC-522 Question:

Leadership Panel Exhibit CLP-ELP-1 – Storm Cost Recovery
(Carrying charges applied to SCRAF) In its proposal, the Company notes, "should PURA implement the SCRAF, which provides for more timely review and recovery of storm and pre-staging costs, the Company accepts the Prime rate from the date of cost incurrence, applied to the net balance of the storm fund and pre-staging reserve fund 6 for storms occurring after March, 2025." (p.143) Did the company consider or analyze setting carrying charges on costs recovered through SCRAF to be equal to the commercial paper index or the utility's actual cost of short-term debt, rather than the prime rate?

a. If yes, provide the analysis conducted and the rationale for proposing the use of the Prime rate instead.
b. If not, explain why the Company did not consider proposing that the carrying charges on SCRAF recovery to be set at either the commercial paper index or actual cost of short-term debt.

OCC-522 Response:

a. and b.

Carrying costs are the mechanism by which the Company recovers its cost of money. Thus, carrying costs must be tied to the actual cost that the Company is incurring to carry the storm deferral. When the storm deferral is relatively larger and carried for a relatively extended time period, then the Company's weighted average cost of capital ("WACC") is its actual carrying cost. If PURA establishes a ratemaking mechanism that provides more systematic reviews and more timely recovery, then the cost of money may be susceptible to approximation with lower cost sources of funds.

The relationship between time and quantity and the cost of capital is clearly demonstrated through a utility's cost of service whereby a utility's rate base (comprised mainly of the Company's plant which is paid back by customers over many years) receives a return at the Company's authorized WACC. Applying the Company's WACC to long-term assets aligns the carrying charge calculation with the manner in which comparable long-term assets are reflected for ratemaking purposes.

Similarly, the WACC is the appropriate rate for calculating carrying charges on long-term funded regulatory assets because it reflects the Company's actual cost of funding those customer "debts", including storm restoration costs, over an extended period of time. Financing obligations – certainly obligations of this magnitude – cannot be supported exclusively through debt financing, whether short-term or long-term. Instead, the Company must balance its capital requirements through a reasonable mix of both debt and equity to ensure financial stability and continued access to reasonably priced capital.

With respect to the appropriate carrying charge rate to utilize for the Storm Cost Recovery Adjustment Factor ("SCRAF"), the Company provided a thorough response to this question in response to LFE-031, in Docket No. 25-12-13. The Company is providing that response as OCC-522, Attachment 1. The analysis shows that: (1) necessary uses of cash routinely exceed available sources of cash, creating a persistent funding gap; (2) commercial paper is a

tool to maintain liquidity, not to finance investments or deferred expenses; and (3) short-term borrowing capacity is limited, and the Company cannot plan to operate at or near its short-term debt capacity without putting its ability to operate the system in severe jeopardy.

Given all of the considerations elucidated by Attachment 1, the Company recognizes that the appropriate treatment of carrying charges may vary based on the regulatory framework established within each jurisdiction. Different regulatory constructs reflect differing policy objectives and mechanisms designed to balance the Company's financing needs with customer impacts. In establishing a going-forward framework for storm cost recovery, the Company agrees that it would be within PURA's discretion to strike a balance between the Company's costs of financing storm costs while ensuring that the Company is not 'profiting' on a force majeure event like a storm. This is the Company's experience in Massachusetts, as well, where the MDPU has authorized a carrying charge rate that is different from and generally less than the Company's WACC, but that still recognizes that the Company is using its longer-term capital resources to finance storm costs (not its shorter term commercial paper source of liquidity). Thus, the Company stated that "should PURA implement the SCRAF, which provides for more timely review and recovery of storm and pre-staging costs, the Company accepts the Prime rate from the date of cost incurrence, applied to the net balance of the storm fund and pre-staging reserve fund for storms occurring after March, 2025."

[iii] EOE-156 Question:

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

EOE-156 Response:

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

A. Overview and Results
B. F-Factor Discussion
C. Impact of 5% Additional Capital Investment
D. Model overview

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

A. Overview and Results

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

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

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

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

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

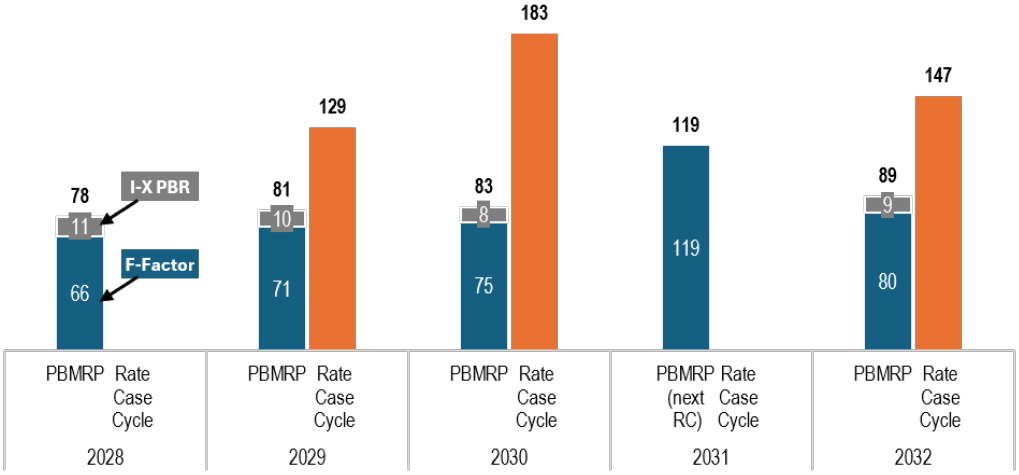
Results of F-Factor Implementation Assuming Capped Forecast Investment

EOE-156, Chart 1, below, provides illustrative rate increases comparing circumstances where the Company is pursuing a traditional rate-case cycle with filings as close to annually as possible under Connecticut law, as compared

to the proposed PBMRP. These amounts assume the Company's revenue requirement proposed in this docket is authorized without modification, except that the Company has used its existing weighted average cost of capital to perform the analysis, in order to isolate the functioning of the F-Factor operation - apart from changes in the cost of capital (i.e., the analysis uses a 9.25% return on equity and 47%/53% debt to equity capital structure). As noted above, the cost-of-service projections are shown in EOE-156, Attachment 1, Worksheet "COS-1 Total," Line 35.

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

EOE-156, Chart 1
Annual Incremental Revenue Increase, $ Millions



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

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

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

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

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

EOE-156, Table 1

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

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

B. F-Factor Operation

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

1. **Like the CT-Bar1 the Company's F-Factor would take effect the first day of the first Rate Year coming out of the rate case, which eliminates the need for Rate Year capital to be embedded in base rates, subject to later downward only reconciliation.** To the extent capital investment currently factored into the Company's proposed revenue requirement for Rate Year 1 is "rolled back" to an earlier date (for example, to a capital investment cutoff date of February 28, 2027 for inclusion in base rates), the F-Factor revenue-requirement calculation would inherently adjust to reflect capital investment as of that cutoff date.

2. **Like the CT-Bar, the Company's F-Factor does not pre-emptively or categorically exclude any type of capital investment.** The Company regularly makes capital investments that do not directly affect the performance of the electric grid the way utility poles, transformers, lines, substations, etc. clearly do, but are nonetheless essential capital investments in the provision of service to customers. Capital investments for facilities safeguarding equipment, information technology enabling self-service customer portals, and vehicles needed for transporting materials to work sites are but a few examples of core capital investments that are necessary and, therefore, inform the F-Factor allowance.

3. **Like the CT-Bar, the Company's F-Factor aligns the capital investment necessary for the target performance of the electric grid outlined in the Company's Targeted System Plan, with the revenues required to support those investments.** In developing the F-Factor the Company sought to establish a

means of tying the F-Factor revenue allowances to the capital investment forecast that would be discussed extensively in this docket. This allows the focus of the TSP to remain on the system needs and plan objectives while simultaneously acknowledging that those needs and objectives, whatever they may be, require some measure of revenue support. The F-Factor serves as a necessary link between the system needs evaluated in this docket and necessary revenues.

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

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

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

6. **Like the CT-Bar, annual reconciliation of the revenue requirement ensures customers ultimately pay only for prudent capital investment while balancing the utility's need to cover the ongoing costs of providing ongoing service.** Critically, the Company's F-Factor proposal does not circumvent prudence reviews – essential pillars of properly-functioning regulatory frameworks – nor undermine the value that effective prudence reviews bring customers. Ultimately, the Company is acutely aware that any capital investment must successfully withstand the scrutiny of a prudence review. Whether that review happens next year, three years from now, or at any other interval, the Company knows the decisions made today must withstand a prudence examination. Any eventual findings of imprudence regarding capital investments made today have significant, negative financial implications, regardless of when those findings are made. Thus, the very expectation of future prudence reviews reinforces the prudence ingrained in decision-making today. Further, the risk of a future finding of imprudence and the negative financial implications thereof eliminates any perceived financial benefit for the Company to "over invest" today.

   Annual reconciliation, including the prudence reviews involved, is a critical element of the Company's PBMRP proposal. As part of each annual PBMRP adjustment effective July 1 each year of the PBMRP2, the Company's actual capital additions for the Prior Year are allowed for inclusion in the calculation of the F

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

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

In total, the Company's proposed F-Factor will provide revenue support for, and ultimately reconcile, the capital investment placed into service from the cutoff date for inclusion in base rates through the effective date of the Company's subsequent rate case at the conclusion of the proposed PBMRP term. Per the Company's proposal, and as depicted in the illustrative attachments for this response, the F Factor would ultimately reconcile capital investments made up to July 1, 2031 (the effective date of the subsequent rate case). Should the subsequent rate case be effective later than the July 1, 2031 illustrative date, the F-Factor would continue to reconcile capital investments placed into service until such time as that rate case does take effect.

C. Impact of 5% additional capital investment

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

As shown in EOE-156, Table 2, below, in the event that the Company's actual capital investments over the period 2027-2031 were 5% greater than current projections, which is a realistic scenario, the Company's proposed F-Factor revenue would not increase, highlighting two crucial design characteristics.

First, the core capital investment forecast provided in this docket is proposed to be a hard cap on the capital plant additions eligible for recovery through the F-Factor. That means the Company, PURA and stakeholders will be adequately informed of the maximum future revenues as calculated today.

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

EOE-156, Table 2

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

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

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

Under PBR, a benefit for the Company is the line of sight it has on a predictable revenue stream that will replace the loss of sales growth associated with the revenue decoupling mechanism, while providing a level of support for the ongoing operation of the system, including needed investment. However, a significant risk for the Company is that its costs will deviate from the "going in revenue requirement" from the minute rates are set through the end of the stay-out term. These cost changes will impact operating expenses, as well as the drivers of investment costs.

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

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

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

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

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

D. Model Overview

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

Key assumptions include:

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

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

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

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

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

The model is organized into three primary sections:

1) **Financial Summary**, which presents illustrative results of the combined effect of the Company's proposed rate increase, PBR framework, and cost projections

2) **PBR Model,** which covers "I – X – CD" and F-Factor

   a. Worksheet "PBR-1 Total PBRA"
   b. Worksheet "PBR-2 Inflation"
   c. Worksheet "PBR-3 F-Factor Summary"
   d. Worksheet "PBR-4 F-Factor"
   e. Worksheet "PBR-5 F-Factor Property Tax"
   f. Worksheet "PBR-6 Capital Forecast"
   g. Worksheet "PBR-7 Going-In Capital RR"
   h. Worksheet "PBR-8 GDP"
   i. Worksheet "PBR-9 ECI"

3) **Cost of service**, which consists of three worksheets, provides a forecast of the actual cost of providing electric service

1) Financial Summary

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

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

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

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

2) PBR

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

a. Worksheet "PBR-1 Total PBRA"

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

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

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

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

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

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

b. Worksheet "PBR-2 Inflation"

This worksheet first aggregates the relevant indices' data points from worksheets 10 and 11 (discussed below), which are shown on Lines 13-16 for GDP-PI and Lines 21-24 for ECI. Each index is then averaged for a given calendar year (Lines 17 and 25), which then form the basis for the annual growth calculations on Lines 18 and 26. As discussed in the Company's pre-filed testimony, the Company is proposing to weight the indices 66.9% for GDP-PI and 33.1% for ECI. The composite resulting inflation is shown on Line 32.

Line 33 provides the -0.03% productivity factor, while Line 34 shows the consumer dividend, which assumes 30 basis points for simplicity of this analysis. The combined result of inflation, productivity factor and consumer dividend is shown on Line 35, which is before the imposition of a 5% cap. To the

extent line 35 exceeds the proposed 5% cap, Line 36 would provide the adjustment such that Line 37, the final result, is the lesser of the 5% cap and Line 35.

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

c. Worksheet "PBR-3 F-Factor Summary"

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

d. Worksheet "PBR-4 F-Factor"

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

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

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

For purposes of this written response, the Company does not detail the calculations of this worksheet here. Instead, the Company refers to the line references provided on the last page of this worksheet

(Model PDF, page 8) for both Attachments 1 and 2, which detail the calculations performed. For emphasis, note that Line 33 captures the accumulation of depreciation recovered in base rates. By design, the F-Factor intentionally reflects this to properly estimate a reasonably true capital driven revenue requirement.

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

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

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

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

f. Worksheet "PBR-6 Capital Expense Forecast"

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

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

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

- Lines 12-16 provide the dollar amounts related to capital-driven costs of services, which are depreciation, property taxes and costs of capital. Amounts shown are currently as proposed in this illustrative model (except where noted), but ultimately will reflect the amounts as approved in this docket.

- Lines 21-28 provide a summarized view of the Company's filed rate base for the Test Year, Rate Year Beginning, Rate Year ending, and Rate Year average balances. These balances serve as the basis (denominators) for establishing the capital-driven costs above as a percentage of approved balances. Those percentages are used on the other "PBR" worksheets, as well as the cost of service worksheet to estimate future costs of service based on approved levels (Lines 30-32)

- Lines 47-81 provide rates for uncollectible expense, gross earnings tax, and the costs of capital as well as necessary calculation of gross-ups to those rates for use in the model's calculations.

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

h. Worksheet "PBR-8 GDP"

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

i. Worksheet "PBR-9 ECI"

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

3) Cost of Service

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

a. Worksheet "COS-1 Total"

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

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

Gross earnings taxes and uncollectible expense are calculated on Lines 33 and 34 as if the full cost of service (Line 28) is in rates.

Non-storm O&M is shown on Lines 38-44, while storm O&M is shown on Lines 45-50, where non-catastrophic costs are identified separately from catastrophic storm / pre-staging funding.

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

Lastly, capital-driven costs of service are shown on Lines 61-67. Depreciation, property tax, uncollectible, gross earnings taxes, and costs of capital are based on the Company's filed cost of service in this docket,

specifically Exhibit CLP REVREQ-2-A, B, C, D Schedules, except that the return on equity (9.25%) and equity capitalization (53%) are shown at currently authorized amounts.

b. Worksheet "COS-2 Capital"

This worksheet functions nearly identically to "PBR-4 F-Factor" except that it relies on actual capital investment projected over the term of the PBMRP. This is essential to understanding actual costs of service, whether or not those costs are supported by revenues. It forms the basis for evaluating the degree to which the F-Factor is sufficient. For additional details pertaining to the mechanics, please see the line references found at the end of this worksheet (or model PDF page 19).

c. Worksheet "COS-3 Property Tax"

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

($ Millions)

Line	Description	Test Year Adjusted *	Rate Year 1 **	Rate Year 2 **	Rate Year 3 **	Rate Year 4 **	
1	Rate Base	6,198	6,856	7,205	7,581	7,977	Company Projections
2	After-tax equity return, as authorized	304	336	353	372	391	Line 1 x 53% x 9.25%
3	After-tax equity return, as proposed	342	379	398	419	440	Line 1 x 53.86% x 10.25%
4	After-tax equity return, difference	$38.3	$42.4	$44.5	$46.9	$49.3	Line 3 - Line 2
5	Income Tax Impact	$14.5	$16.1	$16.9	$17.8	$18.7	(1/(1-.275175)-1) x Line 4
6							
7	* Test Year rate base is adjusted to exclude defered storm and related ADIT, per Exhibit CLP-REVREQ-2, Schedule B-6.2, Lines 52 and 53						
8	** Rate base is provided on a 2-point annual average basis for rate years 1-4						

Exhibit CL-2

CL&P Response to ALLCO-048 and Attachment 1

Authorized returns and ratemaking mechanisms of the Company's affiliates

Date Filed: September 24, 2026

Witness: Douglas P. Horton, Brendan J. O' Brien and Garrett J. Murray
Request from: ALLCO

Question:

For each electric distribution affiliate of Eversource Energy (including Public Service Company of New Hampshire and the Company's Massachusetts electric distribution affiliate): (a) state the currently authorized distribution return on equity and common equity ratio, and identify the proceeding and date in which each was authorized; (b) identify each risk-reducing mechanism (decoupling, storm cost recovery or tracker, multi-year rate plan, capital tracker, earnings sharing) available to that affiliate; and (c) state whether the Company contends that CL&P faces greater business or regulatory risk than each such affiliate and, if so, produce every analysis supporting that contention.

Response:

Please refer to ALLCO-048, Attachment 1, for subparts (a) and (b). The Company has indicated in Attachment 1 whether each company's respective, approved rate plan includes revenue decoupling, storm cost recovery or dedicated mechanism, multi-year rate plan, capital cost recovery, and/or earnings sharing provision. The Company does not agree with the characterization in the question of these mechanisms as "risk reducing mechanisms," given the regulators would not implement these mechanisms unless there were a symmetrically, balancing impact for the utility and its customers and after consideration of the trade-offs inherent in the mechanism. Specifically:

- Revenue decoupling is primarily implemented for policy reasons to eliminate any disincentive that the utility would have for promoting load-conservation initiatives that would reduce sales revenues between base-rate cases. In the course of achieving that policy goal, revenue decoupling operates as a symmetrical reconciliation in which revenues are adjusted up or down to the target level of revenues authorized by the regulator, so that both the utility and customers are held constant to the authorized level of revenue. As shown in Attachment 1, revenue decoupling has been implemented in Massachusetts for NSTAR Electric but has not been implemented for PSNH.

- Storm cost recovery mechanisms operate to provide symmetrical benefits, shielding customers from rate shock associated with the accumulation of incremental storm expenses and limiting carrying costs associated with deferrals, while the utility is allowed timely and adequate recovery of costs it incurs to safely and efficiently restore service to its customers after a significant weather event. By definition, storm cost recovery mechanisms that

operate outside of base rates are intended to cover storms that cannot be reasonably covered through base rates as typical 'ebb and flow' of utility expenses, because to do so would leave customers or the utility paying too much or too little for the obligation. As shown in Attachment 1, although the mechanics differ by jurisdiction, both NSTAR Electric and PSNH have storm cost recovery mechanisms that operate outside of base rates.

- Multi-year rate plans are aimed at stabilizing revenue levels to provide a symmetrical benefit for customers and the utility in terms of enabling necessary rate changes to cover the cost of service, while providing customers rate stability and predictability, along with strong incentives for cost control. Multi-year rate plans that are performance-based and involved in a relatively longer "stay-out" period drive efficiency for the benefit of the utility and customers, due to the fact that the utility needs to operate within the confines of the plan and control its costs in order to maintain financial integrity over the stay-out term. Conversely, customers are protected from utility over-earning during the rate plan through operation of the ESM which, in the Company's experience is implemented in a one-sided manner – to the benefit of customers. The NHPUC approved a 4-year PBR plan as part of the Company's last rate case issued in Docket No. 24-070. The MDPU approved a 5-year PBR plan as part of NSTAR Electric's last rate case in DPU 22-22 (2022).

- Capital cost recovery mechanism outside of a multi-year rate plan have also been implemented by the MDPU for certain targeted investments that are identified as benefitting customers, while providing timely and adequate recovery to the utility in relation to the investments that customers require. The design of the New Hampshire multi-year rate plan encompasses capital cost recovery and PSNH does not currently have a targeted capital cost recovery in place.

- As noted in ALLCO-048, Attachment 1, both PSNH and NSTAR Electric have earnings sharing mechanisms that operate on an asymmetric basis so that the utility is allowed to share earnings above (not below) their authorized return on equity. The earnings sharing mechanisms do not provide additional revenues to the utilities in the event they earn below their authorized return on equity.

As discussed on page of Exhibit CLP-ROE-1, Ms. Bulkley relied on a proxy group of comparable utilities to develop the costs of equity models. Therefore, when assessing business risk, the appropriate comparison is the business risk of the Company as compared to the proxy group to determine where within the range of results the Company's ROE should fall. Accordingly, the requested analysis comparing CL&P to NSTAR Electric and PSNH were not conducted.

The Connecticut Light and Power Company
Affiliates Regulatory Mechanisms

Public Service Company of New Hampshire

Docket No.	Decision Date	Authorized Return on Equity	Common Equity Ratio	Revenue Decoupling	Storm Cost Recovery	Earning Sharing Mechanism	Capital Trackers
				(Yes or No)	*(Yes or No)*	*(Yes or No)*	*(List Each)*
DE 24-070	07/25/25	9.50%	50.00%	No	Yes[1,2]	Yes[3]	N/A

Notes:
1 - PSNH's annual storm fund contribution collected in base rates is $19 million approved in Docket No. DE 24-070.
2 - The PUC has authorize deferral of any storm costs in Docket No. DE 24-070. The Commission deferred any storm costs proposal to ongoing storm dockets. Order No. 28,170 did, however, direct the Company to recover storm costs through the RRA once approved through a storm cost review proceeding.
3 - Triggered when Company's computed ROE exceeds authorized ROE by 25 bps. Sharing is 75%/25%.

NSTAR Electric Company

Docket No.	Decision Date	Authorized Return on Equity	Common Equity Ratio	Revenue Decoupling	Storm Cost Recovery	Earning Sharing Mechanism	Capital Trackers (List each)
				(Yes or No)	*(Yes or No)*	*(Yes or No)*	*(List Each)*
D.P.U. 22-22	11/30/22	9.80%	53.21%	Yes	Yes[1,2]	Yes[3]	Yes[4]

Notes:
1 - Storm Fund (Base Rates): The annual storm fund contribution collected through base distribution rates is $31 million. The storm-fund eligible event threshold is $1.3 million per storm event (meaning routine storms under $1.3M are not contributing to the storm fund deficit).
2 - DPU approved the recovery of exogenous storms outside of base rates as a provision of the PBR. NSTAR Electric is authorized to collect exogenous storm costs through the Storm Cost Recovery Adjustment Factor ("SCRAF") when the combination of any single storm exceeds $30 million and the balance in the storm fund exceeds $75 million and is not otherwise recoverable through the NSTAR Electric Storm Reserve Adjustment Mechanism.
3 - The Earning Sharing Mechanism has a deadband of 100 basis points above the Company's ROE. If the Company's earnings exceed 100 basis points earnings above the deadband will be shared 75 % with customers and 25% with the Company
4 - NSTAR Electric effective capital trackers:
K-Bar (provision of PBR) - M.D.P.U. No. 59H
Grid Modernization - M.D.P.U. No. 73L
Electric Vehicles - M.D.P.U. No. 78G
Electric Sector Modernization - M.D.P.U. No. 84
Provisional System Planning Program - M.D.P.U. No. 81D
Advanced Metering - M.D.P.U. No. 80E
Solar Massachusetts Renewable Target - M.D.P.U. No. 74M
Solar Expansion - M.D.P.U. No. 67I

Exhibit CL-3

CL&P Response to ALLCO-138

Market-to-book cost-of-equity calculation declined (“not available”)

Date Filed: October 09, 2026

Witness: Rima Hyder and Ann Bulkley
Request from: ALLCO

Question:

(Implied cost of equity from market value and growth.) (a) State the long-term earnings-per-share growth rate, dividend growth rate, and rate-base growth rate most recently communicated by Eversource Energy to investors (including in its most recent earnings guidance, investor presentation, and annual report), the date of each communication, and the period to which each applies. (b) State the long-term growth rate(s) used by the ROE Witness in each discounted cash flow model, the source of each (identifying each analyst, service, or calculation relied on), and, for each Proxy Group company, the growth rate assigned. (c) State the long-term nominal growth rate of United States gross domestic product assumed or implied in the ROE Witness's analysis, or, if none, the source the Company regards as authoritative for that figure, and state whether any growth rate used in (b) exceeds it and by how much. (d) Using the relationship M/B = (ROE − g) ÷ (COE − g), where M/B is the market-to-book ratio, ROE is the return on book equity, g is long-term growth, and COE is the cost of equity, compute the cost of equity implied for Eversource Energy at each year-end 2020 through 2025 using (i) Eversource Energy's reported earned return on average common equity and (ii) its communicated long-term growth rate, and produce the calculation; if the Company contends the relationship is inapplicable, state each reason.

Response:

a. Please refer to ALLCO-138, Attachment 1, (pages 4, 19, and 23) for the most recent long-term earnings-per-share growth rate of between 5% and 7% by the end of fiscal year 2030 communicated in the Q2 2026 earnings call presentation dated July 31, 2026. Please refer to ALLCO-138, Attachment 2, (pages 1, 39, and 48) for the most recent dividend growth rate of 5.2% for fiscal year 2025 as compared to 2024 as communicated in the 2026 proxy statement made available on March 27, 2026. Please refer to ALLCO-138, Attachment 3, (page 12) for the most recent rate base growth rate estimate of 8.3% Compound Annual Growth Rate by 2030 as compared to the 2024 rate base as communicated in the Year-End 2025 earnings call presentation dated February 13, 2026.

b. Please refer to Exhibit CLP-ROE-4.

c. Ms. Bulkley did not rely on a forward-looking estimate of GDP growth in her analysis. While the Company has relied on historical measures of GDP growth from the Bureau of Economic Analysis, however since the cost of equity is a forward-looking analysis, the historical GDP growth rates may not be appropriate for the long-term GDP growth rate.

d. The requested analysis was not developed in the preparation of the Company's rate case filing and therefore is not available. Ms. Bulkley did not rely on Eversource Energy in the proxy group used for the estimation of the cost of equity in this proceeding due to the circularity that could occur from relying on the parent company market data to set the ROE for the subject company. This reason was sufficient to eliminate Eversource Energy from the proxy group.

Exhibit CL-4

CL&P Response to ALLCO-100

No analysis of the market prices or yields of the Company's own securities

Date Filed: October 06, 2026

Witness: Ann Bulkley
Request from: ALLCO

Question:

(Follow-up to ALLCO-052.) The response states that Ms. Bulkley "did not rely upon the requested information" and "has not compiled" it. Two subparts did not ask what Ms. Bulkley relied upon. Subpart (d) asked the Company to state whether ANY analysis considering the market prices or yields of the Company's or Eversource Energy's own outstanding securities exists, and if not, to explain why company-specific market evidence was not considered while proxy-group estimates for other companies were. Subpart (e) asked whether the Company contends the risk difference between its preferred stock and its common equity justifies a premium of approximately 400 basis points. Answer both: (a) state affirmatively whether any such analysis exists anywhere in the Company's or its witnesses' files, and if none exists, provide the requested explanation; (b) state the Company's position on subpart (e), or state that it has none; and (c) confirm that the Company does not dispute the accuracy of publicly available market prices and yields for its traded preferred series, including the $3.24 Series G (CNLPL), as of any date Allco may cite.

Response:

a. Ms. Bulkley did not perform an analysis of the Company's or Eversource Energy's outstanding securities. It is Ms. Bulkley's practice to not rely on the parent company of the subject operating company in the analysis of the cost of equity, due to the circularity that could result from relying on the parent company's market data to estimate the required return on a subsidiary.

b. The estimation of the cost of equity is based on market data for a proxy group of publicly traded entities, not an individual security, which may not necessarily reflect the investor-required return on common equity. As noted in the response to subpart (a), Ms. Bulkley eliminates the parent company from the analysis for the reasons indicated. There has been no analysis conducted of the traded value of the preferred stock of the Company in the estimation of the cost of capital. The analysis presented is of the estimated investor-required return on common stock for the proxy group, which more closely approximates the repayment terms of the equity that is included in the Company's capital structure.

c. The Company will review the data reported as publicly available market price data and yields for its traded securities as of the dates indicated by ALLCO and if it can, will confirm the accuracy of that data at the appropriate time.

Exhibit CL-5

Synapse Energy Economics, "Utility Returns on Equity: A Self-Fulfilling Prophecy?"

Matthew Bandyk, January 14, 2026
www.synapse-energy.com/utility-returns-equity-self-fulfilling-prophecy

Synapse
Energy Economics, Inc.

Utility Returns on Equity: A Self-Fulfilling Prophecy?

Matthew Bandyk | January 14, 2026

Tags: equity | energy efficiency | utilities | utility regulation | energy policy

Rising electricity prices have made energy affordability an issue of major public concern. Synapse recently completed reports for the Natural Resources Defense Council and Evergreen Collaborative about strategies to lower electricity prices in Virginia and New Jersey.

Return on Equity is essentially the amount of shareholder profit that investor-owned utilities are allowed to collect from customer bills. Calculating the ROE is an attempt to estimate the utility's cost of equity. Think of cost of equity as the minimum return demanded by investors to supply equity to the utility, or as the opportunity cost to the equity investor: What did the investor give up the opportunity to invest in that is of similar risk to this utility investment?

One of the policy levers we examined in those reports was lowering the return on equity (ROE) for publicly regulated utilities. There has been a growing literature around the argument that regulatory commissions around the country have set ROE too high, resulting in a transfer of wealth from ratepayers to utility shareholders.

The stakes are high because ROE can make up a big portion of the customer bill. A paper from the University of California Berkeley's Energy Institute at Haas calculated the costs to consumers from "excess" ROEs at an average of $7 billion per year.

There are many reasons why regulatory commissions have set ROE too high. These range from the fact that utilities control the timing of when they file for rate cases to the fact that consumer advocacy groups that push back against utility ROE requests tend to have fewer financial resources for engaging in regulatory proceedings than their utility opposition. But in this blog post, we explore another powerful reason:

To put it another way, witnesses for utilities in rate cases frequently argue that the ROE should be set at a level no lower than other utility ROEs across the country. The result is a self-fulfilling prophecy where what one regulatory commission decides on ROE is a reflection of what other regulatory commissions have been deciding. Lost in that circular process is the fundamental question that should inform the ROE: What is the riskiness of this utility investment?

For example, the California Public Utilities Commission recently decided what the cost of capital, including equity, should be for the California investor-owned utilities. Several intervening groups, including the Utility Consumers' Action Network (UCAN) represented by Synapse, argue that the ROE should be set significantly lower than what the utilities are proposing. San Diego Gas & Electric (SDG&E), for example, proposed an 11.25 percent ROE. In comparison, UCAN's witness (Synapse Principal Associate Matthew Bandyk) calculated an 8.87 percent ROE in his testimony. Other intervenors calculated similarly low or even lower ROEs for SDG&E.

SDG&E's witness responded in rebuttal testimony that any ROEs "well below all recently authorized ROEs for electric and gas utilities" should be rejected, including UCAN's. The average national authorized ROE for utilities is most recently around 9.7 percent. The CPUC ultimately approved a 9.93% ROE for SDG&E – above average, but a decrease from SDG&E's previous ROE of 10.23%.

SDG&E's argument here mirrors that used by utility witnesses in many proceedings around the country: for a utility ROE to be fair, it must be comparable to returns that similarly risky companies are receiving elsewhere. This is called a comparable return standard. So, if regulatory commissions generally authorize utilities to collect a certain return from customers, anything below that amount violates this comparable return standard, or so goes the argument.

This line of argument shuts the door to the possibility of a lower ROE than those commissions have been approving, and it locks customers into the ROEs they have been paying. That's a big problem for consumers because there are many reasons to think that commissions do not always get it right when it comes to ROE. Regulatory commissioners are just people—people who are subject to the same kind of biases as all

arbitrary number).

So are customers stuck paying ROEs around 10 percent, even if they are not justified? Is there another way forward?

It turns out there's another way of looking at the comparable return standard—one that makes much more sense than the utility witness argument when we consider the legal thinking behind this standard.

Supreme Court precedents

The comparable return standard stems from a landmark U.S. Supreme Court case, *Bluefield Water Works v. Public Service Commission*, in which the majority opinion stated:

> *A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.*

This comparable return standard was later expanded upon in another landmark case, *FPC v. Hope Nat. Gas Co.*, in which the Court laid out the standards for what constitutes a "just and reasonable" rate of return for public utilities:

> *From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*

other utilities. After all, the argument from SDG&E's witness and other utility witnesses is that authorized return is what matters when considering comparable returns. Most businesses do not have authorized returns. Their returns are simply what they make on the marketplace. Regulated utility companies are in the somewhat unique position of having their return decided by regulators.

Utility interpretations aside, it is clear from the *Bluefield* decision that the Court is talking about not just other utilities, but any other business that has similar risks to utilities ("other business undertakings"). That would include non-regulated businesses that do not have authorized returns the way regulated utilities do.

So looking only at the authorized returns of other utilities fails to meet the plain language of the Supreme Court decisions that created the comparable return standard. We cannot determine if the utility's ROE is "*commensurate with returns on investments in other enterprises having corresponding risks*" by considering authorized return because authorized returns are unavailable for the "other enterprises" one needs to evaluate.

Cost of Equity

What's the alternative? There is another way to interpret what the Court meant by a return "commensurate with returns on investments in other enterprises having corresponding risks." Recall that the ROE is supposed to be an estimation of the utility's cost of equity. Recall also that the cost of equity is the opportunity cost to the equity investor.

In other words, the cost of equity is the same concept as a return "commensurate with returns on investments in other enterprises having corresponding risks." The cost of equity represents the return an investor could have received on similar investments to the company in question.

The cost of equity is commonly estimated using several financial models that use market data to gauge how investors view an asset, such as the stock of a utility company. For example, the Capital Asset Pricing Model (CAPM) estimates cost of equity by calculating the expected return on an investment based on the riskiness of that asset relative to the overall market.

8.87 percent ROE for SDG&E, compared to the utility's authorized ROE of 10.23 percent.

The next step is telling regulatory commissions that when it comes to ROE, their hands are not tied by what other commissioners in other states have decided. By focusing on the cost of equity, commissions can set ROEs that are supported by legal precedent and fair to consumers and utilities.

485 Massachusetts Avenue
Suite 3
Cambridge, MA 02139

Phone: 617-661-3248
Email: communications@synapse-energy.com

Synapse will not respond to career inquiries sent by email, please go to the careers page and apply to one of our open positions.

Synapse
Energy Economics, Inc.

Follow us

©2026 Synapse Energy Economics, Inc. All rights reserved. Privacy Policy

Exhibit CL-6

Market Data on the Company's and Its Parent's Securities

CL&P preferred stock; Eversource Energy common stock;
CL&P first mortgage bonds (ALLCO-143, Attachments 1 and 2); CL&P response to ALLCO-143

Exhibit CL-6 — Market Data Relied Upon in Section IV

A. CL&P cumulative preferred stock. CL&P has $116.2 million (par) of cumulative preferred stock outstanding in thirteen series (Eversource Energy 2023 Annual Report, note on preferred stock of subsidiaries, produced as RRU-072 Attachment 3 at 116–117; reproduced below). The $3.24 Series G ($50 par; ticker CNLPL, quoted over the counter) was quoted at $52.81 on August 12, 2026, a current yield of approximately 6.1 percent.

B. Eversource Energy common stock. Closing price $65.44 on October 20, 2026; annualized dividend $3.15 per share; current dividend yield approximately 4.8 percent; price-to-book ratio approximately 1.52 (October 21, 2026).

C. CL&P first mortgage bonds. The 2025 Series A first mortgage bonds ($400 million, 4.95 percent coupon, issued January 13, 2025, due 2030) were priced at a yield of 4.981 percent, 55 basis points over the benchmark Treasury, at ratings of A1/A/A+ (ALLCO-143, Attachment 1). As of October 2, 2026, the Company’s fifteen outstanding first mortgage bond series traded at market yields between 4.56 and 6.49 percent, the 30-year 2023 Series A at 6.42 percent (ALLCO-143, Attachment 2). The Company’s response to ALLCO-143 and Attachments 1 and 2 follow.

either market prices prevailing at the time of sale, at prices related to such prevailing market prices or at negotiated prices. In 2023, no shares were issued under this agreement. In 2022, Eversource issued 2,165,671 common shares, which resulted in proceeds of $197.1 million, net of issuance costs. Eversource used the net proceeds received for general corporate purposes.

Treasury Shares: As of December 31, 2023 and 2022, there were 10,443,807 and 11,540,218 Eversource common shares held as treasury shares, respectively. As of December 31, 2023 and 2022, there were 349,540,266 and 348,443,855 Eversource common shares outstanding, respectively.

Acquisition of The Torrington Water Company: On October 3, 2022, Aquarion acquired The Torrington Water Company (TWC) following the receipt of all required approvals. The acquisition was structured as a stock-for-stock exchange, and Eversource issued 925,264 treasury shares at closing for a purchase price of $72.1 million.

Acquisition of New England Service Company: On December 1, 2021, Aquarion acquired New England Service Company (NESC), pursuant to a definitive agreement entered into on April 8, 2021. The acquisition was structured as a stock-for-stock merger and Eversource issued 462,517 treasury shares at closing for a purchase price of $38.1 million.

Eversource issues treasury shares to satisfy awards under the Company's incentive plans, shares issued under the dividend reinvestment and share purchase plan, and matching contributions under the Eversource 401k Plan. Eversource also issued treasury shares for its December 2021 and October 2022 water business acquisitions. The issuance of treasury shares represents a non-cash transaction, as the treasury shares were used to fulfill Eversource's obligations that require the issuance of common shares.

On May 3, 2023, shareholders voted to increase the authorized common shares from 380,000,000 shares to 410,000,000 shares.

19. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

The CL&P and NSTAR Electric preferred stock is not subject to mandatory redemption and is presented as a noncontrolling interest of a subsidiary in Eversource's financial statements.

CL&P is authorized to issue up to 9,000,000 shares of preferred stock, par value $50 per share, and NSTAR Electric is authorized to issue 2,890,000 shares of preferred stock, par value $100 per share. Holders of preferred stock of CL&P and NSTAR Electric are entitled to receive cumulative dividends in preference to any payment of dividends on the common stock. Upon liquidation, holders of preferred stock of CL&P and NSTAR Electric are entitled to receive a liquidation preference before any distribution to holders of common stock in an amount equal to the par value of the preferred stock plus accrued and unpaid dividends. If the net assets were to be insufficient to pay the liquidation preference in full, then the net assets would be distributed ratably to all holders of preferred stock. The preferred stock of CL&P and NSTAR Electric is subject to optional redemption by the CL&P and NSTAR Electric Boards of Directors at any time.

Details of preferred stock not subject to mandatory redemption are as follows (in millions, except in redemption price and shares):

Series		Redemption Price Per Share	Shares Outstanding as of December 31, 2023	Shares Outstanding as of December 31, 2022	As of December 31, 2023	As of December 31, 2022
CL&P						
$1.90	Series of 1947	$ 52.50	163,912	163,912	$ 8.2	$ 8.2
$2.00	Series of 1947	$ 54.00	336,088	336,088	16.8	16.8
$2.04	Series of 1949	$ 52.00	100,000	100,000	5.0	5.0
$2.20	Series of 1949	$ 52.50	200,000	200,000	10.0	10.0
3.90%	Series of 1949	$ 50.50	160,000	160,000	8.0	8.0
$2.06	Series E of 1954	$ 51.00	200,000	200,000	10.0	10.0
$2.09	Series F of 1955	$ 51.00	100,000	100,000	5.0	5.0
4.50%	Series of 1956	$ 50.75	104,000	104,000	5.2	5.2
4.96%	Series of 1958	$ 50.50	100,000	100,000	5.0	5.0
4.50%	Series of 1963	$ 50.50	160,000	160,000	8.0	8.0
5.28%	Series of 1967	$ 51.43	200,000	200,000	10.0	10.0
$3.24	Series G of 1968	$ 51.84	300,000	300,000	15.0	15.0
6.56%	Series of 1968	$ 51.44	200,000	200,000	10.0	10.0
Total CL&P			2,324,000	2,324,000	$ 116.2	$ 116.2
NSTAR Electric						
4.25%	Series of 1956	$ 103.625	180,000	180,000	$ 18.0	$ 18.0
4.78%	Series of 1958	$ 102.80	250,000	250,000	25.0	25.0
Total NSTAR Electric			430,000	430,000	$ 43.0	$ 43.0
Fair Value Adjustment due to Merger with NSTAR					(3.6)	(3.6)
Other						
6.00%	Series of 1958	$ 100.00	13	23	$ —	$ —
Total Eversource - Noncontrolling Interest - Preferred Stock of Subsidiaries					$ 155.6	$ 155.6

20. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS

Dividends on the preferred stock of CL&P and NSTAR Electric totaled $7.5 million for each of the years ended December 31, 2023, 2022 and 2021. These dividends were presented as Net Income Attributable to Noncontrolling Interests on the Eversource statements of income. Noncontrolling Interest – Preferred Stock of Subsidiaries on the Eversource balance sheets totaled $155.6 million as of December 31, 2023 and 2022. On the Eversource balance sheets, Common Shareholders' Equity was fully attributable to Eversource parent and Noncontrolling Interest – Preferred Stock of Subsidiaries was fully attributable to the noncontrolling interest.

For the years ended December 31, 2023, 2022 and 2021, there was no change in ownership of the common equity of CL&P and NSTAR Electric.

21. EARNINGS/(LOSS) PER SHARE

Basic earnings/(loss) per share is computed based upon the weighted average number of common shares outstanding during each period. Diluted earnings/(loss) per share is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect of certain share-based compensation awards as if they were converted into outstanding common shares. The dilutive effect of unvested RSU and performance share awards is calculated using the treasury stock method. RSU and performance share awards are included in basic weighted average common shares outstanding as of the date that all necessary vesting conditions have been satisfied.

For the years ended December 31, 2023, 2022 and 2021, there were no antidilutive share awards excluded from the computation.

The following table sets forth the components of basic and diluted earnings/(loss) per share:

Eversource *(Millions of Dollars, except share information)*	**For the Years Ended December 31,**		
	2023	**2022**	**2021**
Net (Loss)/Income Attributable to Common Shareholders	$ (442.2)	$ 1,404.9	$ 1,220.5
Weighted Average Common Shares Outstanding:			
Basic	349,580,638	346,783,444	343,972,926
Dilutive Effect	259,843	463,324	658,130
Diluted	349,840,481	347,246,768	344,631,056
Basic (Loss)/Earnings Per Common Share	$ (1.27)	$ 4.05	$ 3.55
Diluted (Loss)/Earnings Per Common Share	$ (1.26)	$ 4.05	$ 3.54

22. REVENUES

Revenue is recognized when promised goods or services (referred to as performance obligations) are transferred to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. A five-step model is used for recognizing and measuring revenue from contracts with customers, which includes identifying the contract with the customer, identifying the performance obligations promised within the contract, determining the transaction price (the amount of consideration to which the company expects to be entitled), allocating the transaction price to the performance obligations and recognizing revenue when (or as) the performance obligation is satisfied.

The following tables present operating revenues disaggregated by revenue source:

	For the Year Ended December 31, 2023						
Eversource *(Millions of Dollars)*	**Electric Distribution**	**Natural Gas Distribution**	**Electric Transmission**	**Water Distribution**	**Other**	**Eliminations**	**Total**
Revenues from Contracts with Customers							
Retail Tariff Sales							
Residential	$ 5,054.2	$ 1,145.4	$ —	$ 144.7	$ —	$ —	$ 6,344.3
Commercial	2,893.2	637.7	—	69.8	—	(4.8)	3,595.9
Industrial	352.4	186.8	—	4.5	—	(19.7)	524.0
Total Retail Tariff Sales Revenues	8,299.8	1,969.9	—	219.0	—	(24.5)	10,464.2
Wholesale Transmission Revenues	—	—	1,777.5	—	—	(1,310.5)	467.0
Wholesale Market Sales Revenues	625.0	206.7	—	3.9	—	—	835.6
Other Revenues from Contracts with Customers	82.6	5.6	14.6	8.1	1,636.6	(1,628.0)	119.5
Amortization of Revenues Subject to Refund	—	—	4.3	—	—	—	4.3
Total Revenues from Contracts with Customers	9,007.4	2,182.2	1,796.4	231.0	1,636.6	(2,963.0)	11,890.6
Alternative Revenue Programs	(54.3)	35.5	118.9	0.4	—	(106.5)	(6.0)
Other Revenues	20.4	4.0	0.6	1.1	—	—	26.1
Total Operating Revenues	$ 8,973.5	$ 2,221.7	$ 1,915.9	$ 232.5	$ 1,636.6	$ (3,069.5)	$ 11,910.7

Date Filed: October 16, 2026

Witness: Matthew Fallon
Request from: ALLCO

Question:

(Cost of debt and its sensitivity to rating.) (a) For each long-term debt issuance by the Company since January 1, 2018, state the issue date, principal amount, maturity, coupon, yield at issuance, the benchmark Treasury yield on the issue date, the resulting credit spread, and the Company's ratings on that date. (b) State the current market yield and spread to Treasury on each series of the Company's outstanding first mortgage bonds as of the date of the response. (c) Produce every analysis, presentation, or communication since January 1, 2020 in which the Company, Eversource Energy, or any adviser estimated the change in the Company's cost of debt that would result from a one-notch or larger change in its credit rating, and state the Company's best estimate of the increase in the interest rate on new issuances that would result from a one-notch downgrade and from a downgrade from the A category to the Baa/BBB category. (d) State the principal amount of long-term debt the Company expects to issue in each year of the proposed PBMRP term and the amount maturing in each year. (e) Compute, for the Rate Year, the total pre-tax return on rate base (the weighted cost of debt plus the weighted return on equity grossed up for income taxes) at each return on equity listed in Q-ALLCO-142(e), using for each the cost of new debt the Company contends would result under Q-ALLCO-143(c), and produce the calculation.

Response:

(a) Please refer to ALLCO-143, Attachment 1.

(b) Please refer to ALLCO-143, Attachment 2.

(c) The Company is not aware of any analysis, presentation, or communication since January 1, 2020 in which the Company, Eversource Energy, or any adviser estimated the change in the Company's cost of debt that would result from a one-notch or larger change in its credit rating.

The Company currently estimates that a downgrade from the A category to the BBB category would increase the Company's cost of debt by approximately 0.25%.

(d) Please refer to Schedule D-3.0

(e) Please refer to the Company's response to ALLCO-142[i] discussing sensitivities of varying authorized returns on equity in the context of credit ratings.

Prior Referenced Response:

[i] ALLCO-142 Question:

(Credit metrics and rating thresholds.) (a) State the Company's current long-term issuer and first mortgage bond ratings from Moody's, S&P, and Fitch, the date of each rating action since January 1, 2020, and the outlook. (b) For each calendar year 2020 through 2025 and the Test Year, state the Company's CFO pre-WC/debt, FFO/debt, debt-to-capitalization, and cash-flow-to-interest ratios as calculated by each rating agency (or, if the Company does not have the agency calculation, as calculated by the Company using the agency's published methodology), and produce the calculation. (c) Identify the ratio ranges or thresholds that each rating agency has published or communicated to the Company as consistent with the Company's current rating and with the next rating category below it, and produce each rating-agency report, credit opinion, or communication since January 1, 2023 that states such thresholds for the Company or Eversource Energy. (d) State the share of the Company's cash flow from operations in the Test Year that consists of net income, and the share that consists of depreciation, amortization, deferred income taxes, and other non-cash items. (e) Compute the Company's CFO pre-WC/debt and FFO/debt ratios for the Rate Year at authorized returns on common equity of 10.25%, 9.25%, 8.5%, 7.5%, and 6.5%, holding all other inputs at the Company's proposed levels, and state for each the rating category the Company contends would result and the basis for that contention.

ALLCO-172 Response:

(a) Please refer to ALLCO-142 Attachment 1, for CL&P's ratings and outlook from S&P Global Ratings since January 1, 2020.

Please refer to ALLCO-142 Attachment 2, for CL&P's ratings and outlook from Moody's Ratings since January 1, 2020.

Please refer to ALLCO-142 Attachment 3, for CL&P's ratings and outlook from Fitch Ratings since January 1, 2020.

(b) Please refer to ALLCO-142 Attachment 4, for the metrics requested.

(c) Please refer to ALLCO-142 Attachment 5, for reports from S&P Global Ratings on CL&P since January 1, 2023. As discussed on page 2 of 109 in ALLCO-142 Attachment 5, S&P expects "CL&P's stand-alone FFO to debt will average 20%-22% over the forecast period".

Please refer to ALLCO-142 Attachment 6, for reports from Moody's Ratings on CL&P since January 1, 2023. As discussed on page 3 of 73 in ALLCO-142 Attachment 6, "CL&P's stable outlook reflects our expectation that the utility will maintain a ratio of CFO pre-WC to debt of at least 17% over the next 12-18 months. At the same time, the stable outlook reflects the company's ongoing effort to rebuild its relationship with key stakeholders including regulators, state leaders and customers and the potential that storm costs could be recovered through pending regulatory proceedings or securitization" and "CL&P could be downgraded if Connecticut regulatory decisions continue to be contentious or unsupportive of credit quality or if CL&P's financial performance deteriorates such that its ratio of CFO pre-WC to debt falls below 17% on a sustained basis".

Please see ALLCO-142 Attachment 7, for reports from Fitch Ratings on CL&P since January 1, 2023. As discussed on page 2 of 19 in ALLCO-142 Attachment 7, "Through 2027, Fitch forecast CL&P's FFO leverage to average about 4.0x.". Additionally on page 2 of 19 in ALLCO-142 Attachment 7, factors that could, individually or collectively, lead to a downgrade include "FFO leverage exceeds 4.3x on a sustained basis" and "An adverse

implementation of the recent regulatory changes that reduces the stability and predictability of earnings and cash flow and materially weakens CL&P's financial profile".

(d) Please refer to exhibit CLP-REVREQ-2-H-1.2A for the Company's 2025 Form 10K. Per the Company's reported statement of cash flows:

Net Income: $551,329k
Non-Cash Items: $964,867k
Change In Current Assets & Liabilities: $158,970k
Cash from Operations: $1,675,166k

"Non-Cash Items" includes Depreciation, Amortization, Deferred Income Taxes, and Other Non-Cash items, as requested. Note that Test Year Amortization expense includes recovery of substantial under-recovered prior-period costs that built up as the direct result of artificially low RAM rates established over multiple years beginning in 2022. As a result, Test Year Amortization expense may not be indicative of future amortizations, to the extent that reconciling rate adjustments maintain closer alignment with current costs better than they have in the past.

(e) The Company did not perform the requested exercise because it would produce misleading information regarding the Company's credit ratings and would require the Company to speculate regarding how independent rating agencies would evaluate hypothetical outcomes under circumstances that do not exist.

The request presumes that credit ratings can be determined solely by recalculating CFO pre-WC/debt and FFO/debt under a series of assumed ROEs and then assigning a corresponding rating category. That is not how the rating agencies evaluate utility credit quality. Moody's expressly states in its methodology that a "scorecard-indicated outcome is not expected to match the actual rating for each company" and further recognizes that there are "various reasons why scorecard-indicated outcomes may not map closely to actual ratings." In other words, Moody's itself cautions against the precise type of exercise requested here: the use of a limited set of quantitative measures to infer a specific rating outcome.[i]

More fundamentally, Moody's does not evaluate utility credit quality through financial metrics alone. Moody's identifies the regulatory framework as "a key determinant of the credit quality of a utility" and recognizes that utilities can experience financial stress because of "a breakdown or obstacle in the regulatory framework." Consistent with that view, Moody's methodology focuses on the regulatory environment, the consistency and predictability of regulation, the utility's ability to recover its costs and earn returns, and the sufficiency and timeliness of cost recovery. As Moody's explains, the critical issue is whether rates are sufficient to allow the utility to recover its costs and earn a reasonable return, not whether a particular authorized ROE can be associated with a particular financial ratio.[i]

Aquarion Company of Connecticut's ("Aquarion") experience during and after its general rate case, Docket No. 22-07-01, is particularly instructive on this point because it involved the type of exercise requested here. In that docket, PURA evaluated projected credit metrics under multiple ROE and capital structure scenarios and concluded that "the [Aquarion's] credit metrics remain in acceptable ranges set by the credit rating agencies" and that "an ROE set within the ranges presented by EOE, OCC, and [Aquarion] (i.e., 7.765% to 10.35%) would not adversely affect [Aquarion's A3] credit rating."[i] The Authority subsequently relied upon that conclusion in establishing the authorized ROE, explaining that "[a] key determinant in setting an ROE is whether the ROE will allow the utility to maintain its current financial condition and credit rating."[i] In its rationale, the Authority stated that it had conducted a "rigorous analysis" of the effect of various ROE levels on the company's credit rating.[i]

In that instance, PURA evaluated alternative ROE scenarios, compared projected metrics against rating-agency benchmarks, concluded that the approved ROE would not adversely affect Aquarion's credit rating, and relied upon that conclusion in setting rates. That exercise involved the same basic premise underlying this interrogatory: that projected credit metrics and rating-agency thresholds can be used to predict the credit implications of alternative ROE outcomes.

However, despite PURA's conclusions that Aquarion's A3 credit rating would not be adversely impacted by the decision, approximately one year later, Moody's downgraded Aquarion Water Company of Connecticut from A3 to Baa1 and specifically attributed the downgrade to the consequences of the rate order. Moody's stated:

> "The downgrade of Aquarion Water Company of Connecticut reflects a weakening financial profile resulting from the utility's rate order last year, which included a reduced revenue requirement as well as lower returns. The rate order was another indication that the Connecticut regulatory environment has become more challenging and less credit supportive for the state's regulated utilities."[i]

Moody's further explained that Aquarion's lower rating reflected a Connecticut regulatory environment that had become less consistent and predictable, as evidenced by recent regulatory decisions affecting Connecticut utilities.[i] Notably, the factors Moody's cited as driving the downgrade extended beyond the projected financial metrics on which PURA's analysis principally relied.

The requested exercise suffers from the same fundamental limitation. It assumes that all relevant rating considerations remain unchanged except for the effect of a lower ROE on two financial ratios. In reality, rating agencies do not assess utility credit quality that way. A lower ROE is not merely an input to a ratio calculation; depending on the circumstances, it may affect a rating agency's assessment of the utility's ability to earn its return, recover its costs, attract capital, maintain cash flow, and operate within a constructive regulatory framework. From a credit perspective, the relevant question is not what ROE appears in a rate order, but whether the utility can actually recover its costs, earn its authorized return, generate sufficient cash flow, and maintain access to capital. Those outcomes depend on numerous features of the regulatory framework and cannot be inferred from the authorized ROE alone.

Accordingly, the Company cannot reasonably assign hypothetical rating categories to the requested ROE scenarios. More importantly, the Aquarion outcome demonstrates that doing so would not provide a reliable indication of how the rating agencies would actually evaluate the Company's credit quality. The requested exercise would therefore create an appearance of precision that is unsupported by the methodology actually used by the rating agencies and contradicted by the most directly analogous Connecticut experience.

The Connecticut Light and Power Company
Long-Term Debt Issuances Since January 1, 2018

Issuer	Issuance Date	Rating at time of Issuance Moodys/S&P/Fitch	Amount (in millions)	Benchmark Treasury Yield	Spread	Investor Yield	Coupon	Maturity Date
CL&P	3/28/2018	A2/AA-/A+	$ 500	3.084%	0.930%	4.014%	4.000%	4/1/2048
CL&P	4/1/2019	A1/AA-/A+	$ 300	2.846%	1.000%	3.846%	4.000%	4/1/2048
CL&P	9/17/2019	A1/A+/A+	$ 200	1.692%	0.730%	2.422%	3.200%	3/15/2027
CL&P	12/1/2020	A1/A+/A+	$ 400	0.408%	0.350%	0.758%	0.750%	12/1/2025
CL&P	6/30/2021	A1/A+/A+	$ 425	1.480%	0.600%	2.080%	2.050%	7/1/2031
CL&P	1/10/2023	A1/A+/A+	$ 500	3.914%	1.350%	5.264%	5.250%	1/15/2053
CL&P	7/6/2023	A1/A+/A+	$ 300	3.725%	1.200%	4.925%	4.900%	7/1/2033
CL&P	1/23/2024	A1/A+/A+	$ 350	3.948%	0.750%	4.698%	4.650%	1/1/2029
CL&P	8/13/2024	A1/A+/A+	$ 300	3.907%	1.100%	5.007%	4.950%	8/15/2034
CL&P	1/13/2025	A1/A/A+	$ 400	4.431%	0.550%	4.981%	4.950%	1/15/2030

Series	Amount	Coupon	Issue Date	Maturity Date	Market Yield (1)	Spread (1)
2004 Series B	$130,000,000	5.750	9/15/2004	9/15/2034	5.92%	0.64%
2005 Series B	$100,000,000	5.625	4/7/2005	4/1/2035	6.20%	0.92%
2006 Series A	$250,000,000	6.350	6/7/2006	6/1/2036	6.07%	0.79%
2007 Series B	$150,000,000	5.750	3/27/2007	3/1/2037	6.06%	0.78%
2007 Series D	$100,000,000	6.375	9/17/2007	9/1/2037	6.49%	1.21%
2014 Series A	$475,000,000	4.300	4/24/2014	4/15/2044	6.44%	0.76%
2015 Series A	$350,000,000	4.150	5/20/2015	6/1/2045	6.42%	0.74%
2017 Series A	$500,000,000	3.200	3/10/2017	3/15/2027	4.56%	-0.27%
2018 Series A	$800,000,000	4.000	3/28/2018	4/1/2048	6.42%	0.74%
2021 Series A	$425,000,000	2.050	6/30/2021	7/1/2031	5.61%	0.55%
2023 Series A	$500,000,000	5.250	1/10/2023	1/15/2053	6.42%	0.79%
2023 Series B	$300,000,000	4.900	7/6/2023	7/1/2033	5.83%	0.55%
2024 Series A	$350,000,000	4.650	1/23/2024	1/1/2029	5.32%	0.37%
2024 Series B	$300,000,000	4.950	8/13/2024	8/15/2034	5.95%	0.67%
2025 Series A	$400,000,000	4.950	1/13/2025	1/15/2030	5.45%	0.39%

(1) Sourced from Bloomberg on October 2, 2026

Exhibit CL-7

CL&P Response to ALLCO-051

Capital structure; planned first mortgage bond issuances; retained equity

Date Filed: September 24, 2026

Witness: Douglas P. Horton, Brendan J. O' Brien, Garrett J. Murray, and Matthew Fallon
Request from: ALLCO

Question:

With respect to capital structure and expected earnings: (a) state the Company's actual common equity ratio, per books, at the end of the Test Year and as of the most recent quarter, and reconcile any difference from the requested 53.86%; (b) state the amount of long-term debt outstanding at Eversource Energy (the parent) as of the end of the Test Year and state whether any proceeds of parent debt have been invested as common equity in CL&P, quantifying the amounts (i.e., the extent of double leverage); and (c) quantify the expected return on equity to shareholders under the proposed earnings sharing mechanism — 50/50 sharing above the authorized return with no downside adjustment — assuming the requested 10.25% authorized return, producing the distribution or scenario analysis used, and state whether the Company performed any analysis of the asymmetric value of that mechanism; if not, explain why an asymmetric mechanism does not require a lower authorized return.

Response:

a. In recent years, the Company has had to fund significant deferred balances relating to catastrophic storm restoration costs and the Company's Revenue Adjustment Mechanism ("RAM") reconciling rates, including the 2024 Non-bypassable Federally Mandated Congestion Charges ("NBFMCC"). As discussed in response to data request OCC-522[i], including the attachment provided therein, the Company's capital resources are limited. With no foreseeable recovery of the costs in the near term, the Company had to support the growing deferral balance using its limited capital resources, although the deferral offered no operating cash flow with which the Company could service additional debt. To mitigate the financial risk that would otherwise result (from additional debt), the Company took steps to preserve its credit ratings, including maintaining a higher percentage of equity in its capital structure. Consequently, the Company's common equity ratio, per books, was considerably higher than the equity ratio in prior years. Once the artificially low RAM rates were corrected and the corresponding deferred balances were reduced, the need to maintain a higher equity capitalization ratio was lessened.

   Specifically, the Company's common equity ratio on a 5-quarter average basis was 54.56% as of December 31, 2025, and 55.26% as of June 30, 2026. The Company anticipates issuing $1.45 billion of First Mortgage Bonds over the two-year period July 1, 2026 through June 30, 2028, to fund ongoing operations as well as upcoming maturities of $500

million. Additionally, the Company expects to retain approximately $400 million of earned equity over the same timeframe. As shown in the table below, the Company has reflected an equity ratio of 53.86% in the rate year in this proceeding, incorporating assumptions of timely recovery of past and future storm costs, among other proposals in this proceeding.

Please refer to Table 1, below, as well as the Company's filed Exhibit CLP-REVREQ-2, Schedules D-1.0, WP-D-1.1, and D-5.0.

ALLCO-051 Table 1
($ Millions)

	End-of-Period Balance				Average
	June 30, 2026	June 30, 2027	June 30, 2028	2-Year Change	June 30, 2028
Long-term Debt *	$ 5,109.2	$ 5,751.7	$ 6,053.8	$ 944.5	$ 5,873.0
Common Equity	6,769.5	6,812.8	7,171.5	402.0	6,992.1
Preferred Stock	117.0	117.0	117.0	0.0	117.0
Total Capital	$ 11,995.7	$ 12,681.5	$ 13,342.3	$ 1,346.5	$ 13,011.9
Common Equity Percentage of Total Capital					53.86%

** Rate Year average balance is calculated on a 5-quarter average basis*

b. Eversource Energy is a public holding company that holds regulated electric, gas and water affiliates as well as unregulated affiliates. It is simply not possible to associate individual sources of funds, whether at the utility or holding company, with the uses of funds at the operating company level, nor is the business managed in that manner. The management of cash into and out of the Company is a daily undertaking that ultimately includes the passage of billions of dollars out of the Company, to suppliers and employees, as well as into the Company from various sources, including customers. Although the Parent company raises necessary capital through specific sources available, the uses are not connected to any specific source of funds.

Those sources of funds include equity issuances, retained earnings, the use of treasury shares for such programs as dividend reinvestment and 401k match, long-term debt issuances, and, temporarily, short-term debt. These sources of funds as well as the eventual uses vary significantly year to year. Moreover, the Company's credit ratings, such as those issued by Moody's, are determined at the subsidiary level based on the riskiness of its assets, specifically, as well as the degree of financial risk resulting from the Company's

issuances of First Mortgage Bonds. Those bonds include protections, ring fencing, and covenants specific to the Company (i.e not Eversource Energy Parent), and are backed by the Company's (again, not Eversource Energy Parent's) assets in the State of Connecticut.

c. There is no sharing of earnings caused by the setting of base rates with an authorized return incorporated into the approved revenue requirement. Further, the Company does not anticipate that it will over-earn during the term of the PBMRP.

Prior Referenced Response:

---

[i] OCC-522 Question:

Leadership Panel Exhibit CLP-ELP-1 – Storm Cost Recovery

(Carrying charges applied to SCRAF) In its proposal, the Company notes, "should PURA implement the SCRAF, which provides for more timely review and recovery of storm and pre-staging costs, the Company accepts the Prime rate from the date of cost incurrence, applied to the net balance of the storm fund and pre-staging reserve fund 6 for storms occurring after March, 2025." (p.143) Did the company consider or analyze setting carrying charges on costs recovered through SCRAF to be equal to the commercial paper index or the utility's actual cost of short-term debt, rather than the prime rate?

a. If yes, provide the analysis conducted and the rationale for proposing the use of the Prime rate instead.

b. If not, explain why the Company did not consider proposing that the carrying charges on SCRAF recovery to be set at either the commercial paper index or actual cost of short-term debt.

OCC-522 Response:

a. and b.

Carrying costs are the mechanism by which the Company recovers its cost of money. Thus, carrying costs must be tied to the actual cost that the Company is incurring to carry the storm deferral. When the storm deferral is relatively larger and carried for a relatively extended time period, then the Company's weighted average cost of capital ("WACC") is its actual carrying cost. If PURA establishes a ratemaking mechanism that provides more systematic reviews and more timely recovery, then the cost of money may be susceptible to approximation with lower cost sources of funds.

The relationship between time and quantity and the cost of capital is clearly demonstrated through a utility's cost of service whereby a utility's rate base (comprised mainly of the Company's plant which is paid back by customers over many years) receives a return at the Company's authorized WACC. Applying the Company's WACC to long-term assets aligns the carrying charge calculation with the manner in which comparable long-term assets are reflected for ratemaking purposes.

Similarly, the WACC is the appropriate rate for calculating carrying charges on long-term funded regulatory assets because it reflects the Company's actual cost of funding those customer "debts," including storm restoration costs, over an extended period of time. Financing obligations – certainly obligations of this magnitude – cannot be supported

exclusively through debt financing, whether short-term or long-term. Instead, the Company must balance its capital requirements through a reasonable mix of both debt and equity to ensure financial stability and continued access to reasonably priced capital.

With respect to the appropriate carrying charge rate to utilize for the Storm Cost Recovery Adjustment Factor ("SCRAF"), the Company provided a thorough response to this question in response to LFE-031, in Docket No. 25-12-13. The Company is providing that response as OCC-522, Attachment 1. The analysis shows that: (1) necessary uses of cash routinely exceed available sources of cash, creating a persistent funding gap; (2) commercial paper is a tool to maintain liquidity, not to finance investments or deferred expenses; and (3) short-term borrowing capacity is limited, and the Company cannot plan to operate at or near its short-term debt capacity without putting its ability to operate the system in severe jeopardy.

Given all of the considerations elucidated by Attachment 1, the Company recognizes that the appropriate treatment of carrying charges may vary based on the regulatory framework established within each jurisdiction. Different regulatory constructs reflect differing policy objectives and mechanisms designed to balance the Company's financing needs with customer impacts. In establishing a going-forward framework for storm cost recovery, the Company agrees that it would be within PURA's discretion to strike a balance between the Company's costs of financing storm costs while ensuring that the Company is not 'profiting' on a force majeure event like a storm. This is the Company's experience in Massachusetts, as well, where the MDPU has authorized a carrying charge rate that is different from and generally less than the Company's WACC, but that still recognizes that the Company is using its longer-term capital resources to finance storm costs (not its shorter term commercial paper source of liquidity). Thus, the Company stated that "should PURA implement the SCRAF, which provides for more timely review and recovery of storm and pre-staging costs, the Company accepts the Prime rate from the date of cost incurrence, applied to the net balance of the storm fund and pre-staging reserve fund for storms occurring after March, 2025."

Exhibit CL-8

Resume of Christopher M. Little

CHRISTOPHER M. LITTLE

PROFESSIONAL EXPERIENCE

Ecos Energy, Minneapolis, MN *March 2008 to April 2021 and January 2024 to Present*

Chief Operating Officer (January 2024 to Present) and Director of Development (March 2008 to April 2021)

- Arrange construction and long-term financing and manage closings for all company assets
- Responsible for business development for new solar PV facilities
- Site selection and acquisition of land for solar PV facilities
- Project feasibility, energy and financial modeling
- Procurement of major equipment for company solar PV projects
- Negotiate terms of supply agreements and EPC contracts
- Land use entitlements for planned solar PV facilities
- Oversee day to day management of company assets, including operating solar PV plants

Key Accomplishments

- Led the development and construction of 44 solar projects totaling over 75 MWs
- Financed solar PV projects through term loans, new market tax credit financing and sale-leasebacks totaling over $200MM, including 28 sale-leaseback transactions with De Lage Landen Financial Services, PNC Energy Finance and The Huntington National Bank.
- Acquired 91 parcels of land totaling 2,200 acres since 2012.
- Obtained land use entitlements for 20 solar PV projects totaling 35.7 MWs in California, Minnesota, Indiana and Connecticut
- Developed over 95 MW of solar PV projects in 7 states with off-takers including Xcel Energy, Georgia Power, Pacific Gas and Electric, Southern California Edison, Los Angeles Department of Water and Power, Eversource, Northern Indiana Public Service Company, National Grid, VEPP, Inc and numerous municipalities throughout Massachusetts and Connecticut.

The Huntington National Bank, Plymouth, MN *April 2021 – January 2024*

Vice President and Senior Relationship Manager – Provided tax equity financing for solar PV and battery storage projects in the form of sale-leasebacks. Responsibilities included business development, project diligence, negotiation of transaction documents, financial modeling, pricing with ABC, credit risk mitigation and asset management.

Ryland Homes, Eden Prairie, MN *July 2006 – March 2008*

Land Acquisition Manager – Negotiated general terms and conditions for the acquisition of raw land and finished lots for new home construction.

Colliers Turley Martin Tucker, Minneapolis, MN *February 2005 – July 2006*

Associate, Land Brokerage Services – Provided land acquisition and disposition services to land owners and buyers.

We Energies, Milwaukee, WI *July 1999 – February 2005*

Right of Way Agent – Responsible for land/site acquisition and land use entitlements for company assets, including communication towers, gas regulator stations, substations and power plants.

EDUCATION

University of Wisconsin, Madison, WI – Bachelor of Business Administration, May 1999
Major – Real Estate and Urban Land Economics