CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY

Application of The Connecticut Light and	*	
Power Company d/b/a Eversource Energy	*	Docket No. 26-05-10
to Amend its Rate Schedules	*	

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DIRECT TESTIMONY

OF

LINDSAY J. GRIFFIN

ON BEHALF OF

ACADIA CENTER AND CONSERVATION LAW FOUNDATION

October 21, 2026

Table of Contents

I. Introduction 1

II. Purpose of Testimony and Background 9

A. Purpose of Testimony and Background 9

B. Overview of Eversource's Rate Case Filing 14

C. Timeline of the PBR Proceedings Relative to Eversource's Rate Case Filing 25

III. Eversource Bears the Burden of Demonstrating that its Proposed PBMRP is Just and Reasonable and in the Public Interest 27

IV. Eversource Has Not Shown That Its Revenue Adjustment and Capital Funding Mechanisms are Just and Reasonable 33

A. Revenue Adjustment Mechanism / Revenue Cap Formula Design 33

B. Capital Funding Mechanism: The CT-Bar Compared to Eversource's Forecast-Based Mechanism 38

C. Plan Term, Stay-Out Provisions, and Going-In Rate Mechanics 52

V. Eversource Has Not Adequately Supported Its Capital Forecast 53

VI. Eversource Has Not Shown That Its Proposed PIMs Will Improve Performance 59

VII. Taken Together, Eversource's PBR Proposal Would Shift Risk to Customers and Would Not Contain Costs 66

VIII. Eversource's Justifications Do Not Carry Its Burden, and Approving Its Proposal Would Harm the Public Interest Beyond This Case 70

A. The Company Has Not Shown That Its Proposal Serves Customers or the Priority Outcomes 70

B. Approving Company's Proposal Would Create Risks for Future Rate Cases and Weaken the Statewide PBR Framework 72

IX. Recommendations. 75

C. The Authority Should Reject Eversource's Proposed PBMRP 75

D. Primary Recommendation: Apply the Framework Developed in Docket No. 21-05-15 and Its Reopeners 76

E. Alternative Recommendation: Set Rates on a Conventional Cost-of-Service Basis Without First-Generation PBR Mechanics 85

F. Recommendations That Apply in Either Case 87

X. Conclusion and Recommendations 88

List of Exhibits

Appendix A:	Resume of Lindsay J. Griffin
Appendix B:	Docket Time Schedules
Appendix C:	Recommendations

I. INTRODUCTION

Q. MS. GRIFFIN, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lindsay Griffin. My business address is 1111 Broadway, 3rd Fl, Oakland, CA 94607.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I serve as the Senior Regulatory Director, Northeast for Vote Solar, an independent 501(c)(3) nonprofit organization working to repower the United States with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale solar facilities, and to encourage common-sense electrification of the economy, all as part of the transition away from fossil fuel-powered energy consumption. Vote Solar is not a trade group, and it does not have corporate members.

As Senior Regulatory Director, I lead the development and implementation of policy initiatives related to distributed generation ("DG")[1] and distributed energy resources ("DER")[2] more broadly. My portfolio of work also includes clean energy affordability, performance-based regulation (PBR), and other rate design

[1] DG resources include, but are not limited to, (a) photovoltaics (*a.k.a.* solar or solar electric), (b) wind, (c) micro-hydro, and (d) combined heat and power (*a.k.a.* cogeneration). DG resources are typically located closer to load than central power plants and are usually interconnected with the distribution system.

[2] DER technologies include, but are not limited to, (a) DG, (b) energy efficiency, (c) energy storage, (d) demand response, and (e) load shifting. DER are connected to the distribution system.

mechanisms applied to public utilities – all with the goal of expanding access to clean energy for ratepayers in the Northeast. I review regulatory filings, perform technical analyses, and represent the Vote Solar in commission proceedings.

Q. PLEASE DESCRIBE YOUR EXPERIENCE, QUALIFICATIONS AND EDUCATION.

A. My primary focus at Vote Solar is utility regulatory issues related to clean energy accessibility. Prior to joining Vote Solar, I was an Economist at the Massachusetts Department of Public Utilities ("Department") for just under five years. While at the Department, I was the primary staff person who worked on issues related to DG and renewable energy, including net metering, interconnection, energy efficiency and competitive supply. Prior to joining the Department, I was employed by CivicSolar, Inc., a solar PV design and distribution company. I received my undergraduate degrees from the University of Rhode Island. I received a Bachelor of Science degree in Environmental & Natural Resource Economics, and a Bachelor of Science degree in Marine Affairs. My résumé is attached as Appendix A.

Q. HAVE YOU TESTIFIED BEFORE THE AUTHORITY OR BEEN OTHERWISE INVOLVED IN RELATED REGULATORY PROCEEDINGS?

A. I have not submitted testimony to PURA. While employed at Vote Solar, I have participated in several uncontested proceedings, including Docket No. 21-05-15 - PURA Investigation into a Performance-Based Regulation Framework for the

Electric Distribution Companies, Docket No. 21-05-15RE01 - PURA Investigation into Revenue Adjustment Mechanisms for a Performance-Based Regulation Framework, Docket No. 21-05-15RE02 - PURA Investigation into Performance Mechanisms for a Performance-Based Regulation Framework, Docket No. 21-05-15RE03 - PURA Investigation into the Establishment of Integrated Distribution System Planning within a Performance-Based Regulation Framework, and Docket No. 26-06-04 - Implementation of Clean Energy Successor Programs.

In Connecticut, I have also researched, drafted, and supported filings with the Connecticut Department of Energy and Environmental Protection and supported partner organization's advocacy in recent legislative sessions.[3]

I have also engaged in legislative work in Massachusetts, regulatory proceedings before the Massachusetts Department of Public Utilities, and regulatory proceedings before the New York Public Service Commission.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OTHER REGULATORY BODIES?

A. No. I have not.

[3] These engagement include, but are not limited to: DEEP's Electric System Efficiency Study RFI; comments on Project Sunbridge; public comments in PURA's Eversource (Yankee Gas) rate case; presenting at a Connecticut Equity and Environmental Justice Advisory Council (CEEJAC) public quarterly meeting; written testimony to the General Assembly's Executive and Legislative Nominations Committee; testimony on H.B. 5340; and a sign-on letter urging passage of solar legislation to lower energy bills.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Acadia Center and Conservation Law Foundation ("CLF").[4]

Q. PLEASE DESCRIBE ACADIA CENTER.

A. Acadia Center is a nonprofit research and advocacy organization dedicated to advancing clean energy solutions that support a livable climate and a stronger, more equitable economy. Founded in 1998 on the principle that state-level action can drive national progress, the organization works across Connecticut, Maine, Massachusetts, New Hampshire, New York, and Rhode Island.

Q. PLEASE DESCRIBE CONSERVATION LAW FOUNDATION

A. The Conservation Law Foundation (CLF) is a nonprofit environmental advocacy organization headquartered in Boston, Massachusetts. For more than 50 years, it has served communities in all six New England states. CLF combines legal expertise, policy analysis, and regional knowledge to address environmental challenges. CLF's work encompasses climate change, ocean health, clean air and water, environmental justice, and healthy communities

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Section II describes the purpose of my testimony, the Authority's performance-based regulation proceeding in Docket No. 21-05-15 and its reopeners, Docket No.

[4] Acadia Center, CLF and Vote Solar have a longstanding history of collaborating on clean energy issues in Massachusetts and Connecticut, including joint filings in Connecticut.

21-05-15RE01, Docket No. 21-05-15RE02, and Docket No. 21-05-15RE03, and the PBR-related elements of Eversource's filing.

Section III describes the standard Eversource must meet. As the applicant, Eversource bears the burden of demonstrating that its proposed performance based multi-year rate plan ("PBMRP") will produce just and reasonable rates and serve the public interest.

Sections IV through VI evaluate the Company's proposed revenue adjustment and capital funding mechanisms, the planning basis for its capital forecast, and its proposed performance incentive mechanisms ("PIMs"), and explains why the Company has not carried its burden as to any of them.

Section VII describes the cumulative effect of those mechanisms on the allocation of risk between the Company and its customers.

Section VIII responds to the Company's justifications for departing from the framework developed in Docket No. 21-05-15 and explains why approving the proposal would harm the public interest beyond this case.

Section IX sets out my recommendations, and Section X concludes.

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. My conclusions are as follows:

Eversource bears the burden of demonstrating that its proposed PBMRP will produce just and reasonable rates and serve the public interest. It has not carried that burden.

The Company's proposed mechanisms shift cost and risk to customers and weaken cost containment. Its capital funding mechanism allows the Company to earn a return on new capital before the Authority has determined that the investment was prudent, up to a level set by the Company's own forecast; its revenue cap formula applies productivity discipline to operation, maintenance and administrative ("OM&A") costs only; and it offers its PIMs only on the condition that its plan is approved.

The capital forecast that would set the Company's capital recovery for the plan term has not been tested through the kind of planning process needed to show it reflects necessary investment. The Integrated Distribution System Plan ("IDSP") process proposed in RE03 PFD No. 2 illustrates what that should involve: a grid needs assessment; a load forecast with low, middle, and high scenarios at the system, planning region, substation, and feeder levels; a solution selection process that considers non-wires alternatives; and stakeholder engagement through a Joint Working Group.[5] The Company's Targeted System Performance Plan has none of these features. Its load forecast is built at the substation level, varies only weather assumptions, and was prepared without stakeholder review.[6]

The Company has not shown that its departures from the design the Authority and stakeholders developed through Docket No. 21-05-15 and its reopeners, Docket No. 21-05-15RE01 through RE03, would benefit customers if adopted by the

[5] Docket No. 21-05-15RE03, July 17, 2026 Proposed Final Decision No. 2 (RE03 PFD No. 2), at pages 9, 18, 30, 34.

[6] Eversource Response to Interrogatory OCC-574 (OCC-574).

Authority. Eversource describes its changes as remedying "the flaws that would ultimately hinder PURA's (draft) PBR model from supporting the necessary stay-out terms."[7] That explanation concerns the Company's ability to commit to a stay-out, not the benefits to customers.

Taken as a whole, the Company's PBR proposal functions as a conventional cost-of-service filing described in the terminology of performance-based regulation. It does not advance the priority outcomes the Authority adopted to implement the Take Back Our Grid Act. My conclusions rest on the merits of the Company's proposal, not on whether it matches the Proposed Final Decisions in the reopeners. The PBMRP proposal would not produce just and reasonable rates, and it would not advance the nine priority outcomes the Authority adopted in its Phase 1 Decision.

Q. BASED ON YOUR CONCLUSIONS, WHAT DO YOU RECOMMEND TO THE AUTHORITY?

A. I recommend that the Authority:

(1) Reject the Company's proposed PBMRP, including its revenue adjustment mechanism, capital funding mechanism, and PIMs portfolio, because the Company has not demonstrated that the proposal will produce just and reasonable rates, serve the public interest, or advance the priority outcomes adopted in the Phase 1 Decision;

[7] OCC-423, at page 2.

(2) To the extent it adopts PBR mechanisms for Eversource in this proceeding, apply the framework developed in the RE01, RE02, and RE03 Proposed Final Decisions, as described in Section IX: set going-in rates for the first rate year without relying on the Company's capital forecast, direct Eversource to refile its Targeted System Performance Plan so that it conforms to the IDSP requirements in RE03 PFD No. 2, and base capital funding for the remaining plan years on the refiled plan once it has been reviewed;

(3) If it declines to implement PBR as outlined in the reopeners, set the Company's base distribution rates on a conventional cost-of-service basis, without adopting the Company's proposed revenue adjustment or capital funding mechanisms;

(4) Regardless of whether it adopts recommendation (2) or (3), adopt the proposed RE02 performance mechanisms, with the changes described in Section IX, with fixed dollar penalties and, where retained, incentives, effective whether or not a multi-year plan is approved; consider the net risk and earnings opportunity of an adopted PIM portfolio in evaluating the Company's risk when setting its return on equity; require a Comprehensive IDSP in accordance with the final decision in Docket No. 21-05-15RE03; and not approve any mechanism that sets capital recovery from a multi-year forecast until that forecast has been reviewed through a process that conforms to the IDSP requirements; and

(5) State in its Final Decision that nothing decided here sets precedent for the design of multi-year rate plans or prejudges the statewide framework being developed in the PBR reopeners dockets.

II. PURPOSE OF TESTIMONY AND BACKGROUND

A. Purpose of Testimony and Background

Q. HAVE YOU REVIEWED THE TESTIMONY AND OTHER SUPPORTING DOCUMENTS SUBMITTED BY EVERSOURCE IN THIS PROCEEDING?

A. Yes. I have reviewed the relevant filings pertaining to Eversource's proposed PBMRP, including company-filed exhibits and discovery responses that informed my analysis and recommendations herein.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to help the Authority determine whether it should approve the PBR elements of Eversource's rate application. My testimony will show that the Company has not carried its burden of demonstrating those elements would produce just and reasonable rates or serve the public interest. It will show that a different course of action would better serve customers and be more consistent with Conn. Gen. Stat. § 16-244aa, which requires the Authority to investigate, develop, and adopt a PBR framework for the electric distribution companies.[8]

To that end, my testimony first describes the standard the Company must meet in this proceeding and the record the Authority developed in Docket No. 21-05-15 and its reopeners.

[8] https://law.justia.com/codes/connecticut/title-16/chapter-283/section-16-244aa/.

Second, I evaluate the performance-based ratemaking elements of Eversource's rate application against that standard and record. These elements are the proposed revenue adjustment mechanism, capital funding mechanism, PIMs portfolio, and Targeted System Performance Plan. The evaluation focuses on whether those elements would produce just and reasonable rates and advance the priority outcomes the Authority adopted in its Phase 1 Decision in Docket No. 21-05-15. In particular, it asks whether they would improve the efficiency of utility spending, contain costs for ratepayers, and hold the Company accountable for measurable outcomes.

Third, based on that evaluation, it recommends how the Authority should proceed.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE AUTHORITY'S PERFORMANCE-BASED REGULATION PROCEEDING.

A. In May 2021, the Authority opened Docket No. 21-05-15 to investigate, develop, and adopt a performance-based regulation ("PBR") framework pursuant to the Take Back Our Grid Act (Public Act 20-5 § 1, codified at Conn. Gen. Stat. § 16-244aa), enacted in the wake of the August 2020 Tropical Storm Isaias.[9] The Take Back Our Grid Act required PURA to open a proceeding by June 1, 2021 "to investigate, develop and adopt a framework for implementing performance-based regulation of each electric distribution company."[10] First, the framework must establish standards and metrics for measuring utility performance on objectives

[9] Docket No. 21-05-15RE01, July 14, 2025 Proposed Final Decision (RE01 PFD) at pages 1-2; RE03 PFD No. 2, at page 2.

[10] Conn. Gen. Stat. § 16-244aa(b); RE01 PFD at page 4; RE03 PFD No. 2, at page 5.

that serve ratepayers or the public, such as safety, reliability, affordability, equity, and resilience. Second, it must specify how and when those standards will be used to assess the adequacy of service and the reasonableness of rates under Conn. Gen. Stat. §§ 16-19e and 16-19a. Third, it must identify the mechanisms that will align utility performance with those standards, including a review of revenue decoupling.[11]

On April 26, 2023, the Authority issued its Phase I decision adopting four regulatory goals, five foundational considerations, and nine priority outcomes "to guide the Authority's development and adoption of a PBR framework in Connecticut".[12]

The RE01, RE02, and RE03 proceedings reflect a substantial multi-year, multi-stakeholder record, including a combined technical meeting on May 21, 2025, addressing all three reopeners holistically. RE01 alone spanned sixteen technical meetings, thirteen sets of interrogatories, two straw proposals, and three rounds of written comments, and culminated in a Proposed Final Decision issued July 14, 2025.[13] RE02 involved four working group meetings, ten technical meetings, and approximately thirty-two motions, briefing, and oral argument, and produced two Proposed Final Decisions, issued July 14, 2025 and July 27, 2026.[14] RE03

[11] Conn. Gen. Stat. § 16-244aa(b)(1)–(3).
[12] RE03 PFD No. 2, at page 2 & footnotes 2-4 (citing Docket No. 21-05-15, April 26, 2023 Decision (Phase 1 Decision), at pages 10-19).
[13] RE01 PFD, at pages 3-4 & n. 8.
[14] Docket No. 21-05-15RE02, July 27, 2026 Proposed Final Decision No. 2 (RE02 PFD No. 2), at pages 3-5 & nn. 11-15.

involved eleven technical meetings, a concept paper and revised concept paper, a straw proposal, seventeen motions, oral argument, and produced two Proposed Final Decisions, issued August 8, 2025 and July 17, 2026.[15] The Authority has not yet issued a second Proposed Final Decision in RE01. Participants across the three dockets included Eversource, United Illuminating, the Office of Consumer Counsel, the Authority's Office of Education, Outreach and Enforcement, the Attorney General, the Department of Energy and Environmental Protection, Acadia Center, Connecticut Industrial Energy Consumers (CIEC), the Connecticut Green Bank, Operation Fuel (now Generation Power CT), Vote Solar, Sunrun, Sentient Energy, Save the Sound, Conservation Law Foundation, the Center for Children's Advocacy, and the Utility Workers Union of America, System Smart LLC, Neighborhood Housing Services of New Haven, Sustainable Fairfield and Fairfield Forestry Committee.[16]

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15 RE03 PFD No. 2, pages 3-5.

16 RE02 PFD No. 2, at page 6; RE03 PFD No. 2, at page 5; Docket No. 21-05-15RE01, Comments of Vote Solar, Conservation Law Foundation, Save the Sound, Neighborhood Housing Services of New Haven, Fairfield Forestry Committee, and Sustainable Fairfield (Aug. 11, 2023), at page 1; Docket No. 21-05-15RE02, Comments of Vote Solar, Acadia Center, Conservation Law Foundation, Save the Sound, Fairfield Forestry Committee, Sustainable Fairfield, and Neighborhood Housing Services of New Haven (Dec. 15, 2023), at page 1; Docket No. 21-05-15RE03, Comments of the Advocates on PURA Straw Proposal (May 7, 2025), at page 1; Docket Nos. 21-05-15RE01 and 21-05-15RE02, Written Exceptions of the Advocates on Proposed Final Decisions (Aug. 15, 2025), at page 1.

Q. WHAT REGULATORY GOALS, FOUNDATIONAL CONSIDERATIONS, AND PRIORITY OUTCOMES DID THE AUTHORITY ADOPT IN THE PHASE 1 DECISION OF DOCKET NO. 21-05-15?

A. In its April 26, 2023, Phase 1 Decision in Docket No. 21-05-15, the Authority adopted a framework of four regulatory goals, five foundational considerations, and nine priority outcomes to guide the development of performance-based regulation in Connecticut.[17]

The four regulatory goals are: (1) Excellent Operational Performance, (2) Public Policy Achievement, (3) Customer Empowerment and Satisfaction, and (4) Reasonable, Equitable, and Affordable Rates.

The five foundational considerations are: (1) Safety, (2) Equity, (3) Economic Opportunity, (4) Risk Distribution, and (5) Transparency.

The nine priority outcomes are: (1) Business Operations and Investment Efficiency, (2) Comprehensive and Transparent System Planning, (3) Distribution System Utilization, (4) Reliable and Resilient Electric Service, (5) Social Equity, (6) GHG Reduction, (7) Customer Empowerment, (8) Quality Customer Service, and (9) Affordable Service.

These are not proposals awaiting a final decision in the reopeners. The Authority adopted them in 2023, consistent with the Take Back Our Grid Act, and it has used them since then to evaluate every mechanism considered in RE01, RE02, and

[17] Docket No. 21-05-15, April 26, 2023 Decision (Phase 1 Decision), at pages 10-19 (regulatory goals, at page 13; foundational considerations, at pages 14-15; priority outcomes, at page 16); see also RE01 PFD at page 2 & nn. 1-3; RE03 PFD No. 2, at page 2 & nn. 2-4.

RE03. They are therefore the appropriate yardstick for deciding whether the Company's proposed PBMRP serves the public interest.

B. Overview of Eversource's Rate Case Filing

Q. WHAT IS THE REVENUE REQUIREMENT EVERSOURCE REQUESTS IN THIS RATE CASE, AND WHAT WOULD BE THE IMPACT ON CUSTOMERS IF APPROVED?

A. In its original filing, Eversource states that its amended base distribution rates are necessary to address a distribution revenue operating deficiency of approximately $727 million, inclusive of costs associated with the 2018 through March 2025 storms, or approximately $451 million exclusive of those storm costs. The Company states that if its request is approved without modification, it would produce an approximately 16 percent increase in the Company's overall total revenues, and a 50 percent increase in distribution revenue if isolated to that portion of customers' bills.[18]

Item	Amount
Revenue deficiency, including 2018 – March 2025 storm costs	~ $727 million[19]
Revenue deficiency, excluding those storm costs	~ $451 million
Increase in overall total revenues	~ 16%
Increase in distribution revenue	50%

[18] Docket No. 26-05-10, Application (Application), at pages 2-3, 12.

[19] The $727 million figure and associated bill impacts include costs that were then pending in Docket No. 25-12-13. On July 29, 2026, the Authority issued its decision in that docket. It found $861.5 million of the Company's requested catastrophic storm costs prudently incurred, denied the Company's request for $396.7 million in retrospective carrying charges, and directed that the eligible balance be addressed through securitization in Docket No. 26-04-04 rather than through base distribution rates. Decision, Docket No. 25-12-13 (July 29, 2026), at pages 1–2. The Company's request exclusive of storm costs is approximately $451 million. (Application, at pages 2-3 & n.2).

For residential customers, Eversource estimates a total annual bill impact of 18 percent (an average monthly increase of approximately $32.91) if the Company's proposals are approved as filed, inclusive of storm costs. Excluding storm costs, Eversource estimates an 11 percent annual bill impact, or an average monthly increase of approximately $20.[20] The request is built on a proposed Rate Year average rate base of approximately $6.8 billion, reflecting roughly $3.3 billion in net utility plant additions since the Company's last base rate case, and a requested return on equity of 10.25 percent, producing an overall weighted cost of capital of 7.74 percent.[21]

Item	Amount
Residential annual bill impact, with storm costs	18% (~$32.91 per month)
Residential annual bill impact, without storm costs	11% (~$20 per month)
Rate Year average rate base	~$6.8 billion
Net utility plant added since the last rate case	~$3.3 billion
Requested return on equity	10.25%
Overall weighted cost of capital	7.74%

Q. PLEASE PROVIDE AN OVERVIEW OF THE PBR-RELATED ASPECTS OF EVERSOURCE'S FILING.

A. On July 14, 2026, Eversource filed this rate case, proposing a first-generation PBMRP that includes an "I-X"[22] revenue adjustment mechanism, a separate

[20] Application, at page 3.
[21] Id.
[22] An "I-X" revenue adjustment mechanism adjusts a utility's allowed revenues each year by the rate of inflation (the "I-Factor") minus an expected rate of productivity improvement (the "X-Factor"), so that rates track costs a reasonably efficient utility would incur rather than the utility's actual spending.

capital funding mechanism, a PIMs portfolio, and a five-year "Targeted System Performance Plan".[23] Eversource states that its proposal "is generally consistent with the framework discussed in Docket No. 21-05-15RE01," while acknowledging in the same testimony that the Authority had not yet issued a final decision in that docket as of the filing date.[24] Eversource further states that it "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".[25]

Q. DID EVERSOURCE ADEQUATELY INCORPORATE PBR-RELATED MECHANISMS INTO ITS FILING?

A. No. Eversource's proposal borrows the structure of the framework developed in RE01, RE02, and RE03, including a four-year term, an upside-only earnings sharing mechanism, a Z-Factor, and reliability PIMs. But it removes or weakens the following cost containment features included in the framework: the CT-Bar's exclusion of a return on new capital until prudence is established, a revenue cap that applies to total costs, an inflation index and productivity study consistent with the RE01 PFD, and an Authority-reviewed and approved IDSP as the planning

[23] Application, at pages 2, 5-6; Docket No. 26-05-10, July 14, 2026 Exhibit CLP-PBR-1 (Exhibit CLP-PBR-1), at pages 59-60, 66-69.
[24] Exhibit CLP-PBR-1, at page 60.
[25] Docket No. 26-05-10, Eversource Response to Interrogatory OCC-423 (OCC-423), at page 2.

basis for capital spending.[26] Those features were designed to work together to effectively contain costs. Without them, the proposal does not advance the priority outcomes the Authority adopted in its Phase I Decision, and the Company has not shown that the resulting rates would be just and reasonable.

Q. IS THE COMPANY'S PROPOSAL "GENERALLY CONSISTENT WITH THE FRAMEWORK DISCUSSED IN DOCKET NO. 21-05-15RE01" AND ITS REOPENERS?[27]

A. No. As I explain further below, the Company's proposed PBMRP, PIMs portfolio, and Targeted System Performance Plan are inconsistent with the framework the Authority and stakeholders developed through Docket No. 21-05-15 and its RE01, RE02, and RE03 reopeners. Eversource was an active participant throughout Docket No. 21-05-15 and its reopeners and had every opportunity to shape the framework. In RE01 it argued that the CT-Bar was "unworkable" because it excluded the costs of capital; the Authority considered that argument and proposed to adopt the CT-bar without it.[28] However, the Company now raises the same objection here, asking the Authority to adopt in this rate case the same design it did not secure in the reopeners.[29]

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[26] The CT-Bar is a capital funding mechanism proposed in the July 14, 2025 RE01 Proposed Final Decision, building on the RE01 Revised Straw Proposal. It would fund capital additions in the utility's Capital Plan, including IDSP-supported investments, by recovering only depreciation, property tax, and gross earnings tax expense, with no return until the investment is found prudent in the next rate case, subject to a downward-only reconciliation. (RE01 PFD, at pages 31–40).

[27] The Company describes its proposal as "generally consistent with the framework discussed in Docket No. 21-05-15RE01" (Exhibit CLP-PBR-1), at page 60, lines 1-5).

[28] RE01 PFD, at pages 32, 35.

[29] OCC-423, at page 3.

These differences matter because each departure removes a protection for customers. Three examples illustrate the point:

(1) On the revenue adjustment mechanism, Eversource adopted the "I-X" formula concept from RE01 but applied it to OM&A costs only, leaving capital outside any formula. It also departed from the specific inputs the RE01 PFD proposes. The RE01 PFD would base the I-Factor on Gross Domestic Product – Price Index ("GDPPI") and would require the total factor productivity ("TFP") study underlying the X-Factor to use at least three outputs: customer count, delivered energy, and peak demand.[30] Eversource instead proposes a composite index of utility labor costs and Gross Domestic Product – Implicit Price Deflator for Final Sales to Domestic Purchasers ("GDP-FSDP"), and its consultant's productivity study uses the number of customers as its only output.[31] A study with customers as its only output does not account for growth in energy delivered or peak demand, so it cannot show whether the resulting X-Factor reflects the productivity gains customers should expect. The Company confirmed that its X-Factor applies only to OM&A costs, while capital revenue is adjusted separately based on capital placed in service.[32] The Company also describes its I-Factor as based on GDPPI and an Employment Cost Index, which

30 RE01 PFD, at page 25.
31 Exhibit CLP-PBR-1, at pages 34-35, 38, 63.
32 Docket No. 26-05-10, Eversource Response to Interrogatory CLF-AC-005 (CLF-AC-005), at page 2 (quoting CLF-AC-002(b)).

differs from Ms. Frayer's description of a composite of a utility labor cost index and GDP-FSDP.[33] The Company should clarify which index it is proposing.

(2) On capital funding, Eversource replaced the proposed CT-Bar with its own "F-Factor." The Company describes the F-Factor as tracking the CT-Bar "as close as possible" except in three respects, the most significant of which is that the F-Factor would collect a return on new capital during the plan term, before the Authority has found that capital prudent.[34] The CT-Bar, as developed and proposed through the RE01 reopener proceedings, deliberately withholds that return until prudence is established in the next rate case.[35] By the Company's own estimate, that difference is worth $15.6 million in Rate Year 1, rising to $39.5 million in Rate Year 4, or $124.1 million in total.[36] The Company estimated the pretax return on incremental rate base included in the F-Factor at $31 million to $36 million per year, or about $133 million over the four rate years, calculated at its currently authorized 9.25 percent return on equity rather than the 10.25 percent it requests in this case.[37] On either estimate, F-Factor would allow the Company to collect a return on up to $120 million over the plan term, *before the Authority conducts a prudence review*.

(3) On performance mechanisms, Eversource proposed reliability PIMs that follow the general structure of the RE02 designs, but changed their baselines

[33] CLF-AC-001, at page 11.
[34] OCC-423, at pages 4, 10.
[35] RE01 PFD, at pages 33, 36–39.
[36] OCC-423, at page 7.
[37] CLF-AC-004, at page 2 & Att. 1.

and payout structure, folded the Level 1 DER Interconnection PIM into a composite "Customer Suite" with a Company-selected target, omitted the NWS Shared Savings Mechanism, and offers all of its PIMs as contingent on approval of its multi-year plan.[38] The RE01 Proposed Final Decision makes performance mechanisms applicable whether or not a utility accepts a multi-year rate plan.[39] As I explain in Section VI, each of these changes weakens the Company's accountability for performance.

The RE01/RE02/RE03 Proposed Final Decisions represent the Authority's considered judgment, reached after years of stakeholder engagement about how a PBR framework for Connecticut should be designed. The three dockets are at different procedural stages: the Authority issued second Proposed Final Decisions in RE03 and RE02 in July 2026, while the most recent draft decision in RE01 is the Proposed Final Decision issued in July 2025. Although the RE01 Proposed Final Decision has not been updated, it remains the Authority's most recent guidance on revenue adjustment mechanisms. As the applicant, Eversource bears the burden of demonstrating that its proposed rates and ratemaking mechanisms are just and reasonable.[40] Departing from the Authority's proposed design is not itself a flaw. But where the Company proposes mechanisms that do depart from that design, the Company should be expected, at a minimum, to identify each

[38] Docket No. 26-05-10, July 14, 2026 Exhibit CLP-ELP-3 (Exhibit CLP-ELP-3), at pages 1-2; Docket No. 26-05-10, July 14, 2026 Exhibit CLP-ELP-1 (Exhibit CLP-ELP-1), at pages 50, 103-117.

[39] RE01 PFD, at page 10.

[40] Conn. Gen. Stat. § 16-22; also see Section III, *infra.*

departure, explain the reasons for it, compare the outcomes customers could expect under each design, address the risks its alternative shifts to customers, and explain why its alternative design both (1) better serves the priority outcomes adopted in the Phase 1 Decision and (2) produces just and reasonable rates. The Company has not done so. Without that explanation, the Authority has no basis for giving the Company's design more weight than the framework developed on the reopener record.

The Company stated that it "did not perform additional analysis," and it produced no analysis comparing customer outcomes under its design with those under the Proposed Final Decisions.[41] Its explanations concern its own ability to commit to a stay-out, not any benefits to customers. A well-designed performance-based framework shifts risk to the utility for underperformance and rewards it only for demonstrated results, using mechanisms that are interdependent by design: the capital-funding tool, the productivity-based revenue cap, and the incentive mechanisms all lean on one another to produce an optimal risk allocation. Eversource's proposal removes the return-exclusion feature from capital recovery, removes the total-cost discipline from the revenue cap, and offers its PIMs only if the Authority approves its proposed PBMRP.[42] Each departure moves the recovery mechanism closer to a conventional rate-base, rate-of-return recovery where costs are ordinarily recovered once and not reconciled downward, and

[41] CLF-AC-001, at page 13; CLF-AC-003, at page 2; CLF-AC-005, at pages 1-2.
[42] Exhibit CLP-ELP-1, at pages 50, 115.

incentive payments are structured as generalized compliance metrics rather than as sharply targeted rewards for outperformance. Layered together, Eversource's PBMRP proposal functions less like a performance-based rate plan and more like a traditional cost-of-service filing cloaked in the guise of PBR. The Company itself describes both its PBMRP and a cycle of traditional rate cases as "designed to roughly track with the cost of service."[43]

Q. DOES PERFORMANCE-BASED REGULATION HELP ADDRESS THE CAPITAL BIAS IN TRADITIONAL COST-OF-SERVICE REGULATION?

A. Yes, when it is designed properly. Under traditional cost-of-service regulation, a utility earns a return on the capital it adds to the rate base but earns no return on its operating expenses. That gives the utility a financial reason to favor capital-intensive solutions over lower-cost operational or non-wires alternatives, and to spend on infrastructure rather than become more efficient. At the same time, cost-of-service regulation provides only a limited incentive to control operating costs: prudently incurred O&M expenses are recovered dollar-for-dollar in rates, without a return, so while the utility has no reason to increase them, it also has little reason to reduce them beyond the savings it can retain between rate cases, which are reset to actual costs at the next rate case.

A well-designed PBR framework blunts this bias by placing capital and operating costs under the same productivity discipline and by tying earnings to performance

[43] CLF-AC-001, at page 30 (EOE-156).

rather than the size of rate base. The framework developed throughout the RE01 proceeding was built to do exactly that. It includes a Revenue Cap Formula that applies to total costs (i.e., capital and OM&A together) and the CT-Bar withholds any return on new capital until the investment is determined prudent.[44] Eversource's proposed PBMRP does not correct this bias. The Company's I-X formula applies productivity pressure only to OM&A costs, while capital is recovered through a separate forecast-based mechanism that collects the capital revenue requirement, which ordinarily includes a return on rate base, as plant enters service, up to the Company's own forecast.[45] In practice, up to the level of its capital forecast, every dollar the Company can shift from an operating solution to a capital solution escapes the productivity factor and moves into a mechanism that earns a return. The Company's proposal gives it two reasons to spend more. First, any cost it shifts from operations to capital avoids the productivity factor and earns a return. Second, the Company's proposed productivity factor itself is negative (−0.03 percent), so it applies no productivity pressure of its own. Even combined with the Company's proposed 0.30 percent Consumer Dividend, the net annual offset to inflation would be only about 0.27 percent. That offset would apply to a cost level the Company's own consultant found was 11.9 percent above benchmark on average from 2015 through 2024, and 31.5 percent above benchmark in 2024.[46] Like cost-of-service regulation, the proposal rewards

[44] RE01 PFD, at pages 5, 20-21 & n. 19, 31-41.
[45] Exhibit CLP-PBR-1, at pages 42, 68.
[46] Id., at pages 56, 64.

spending over efficiency. The Company offers three responses to this incentive, and none of them remove it.

First, its consultant states that, relative to its peers, the Company "has historically relied more heavily on OM&A expenditures than capital-related expenditures." But the Company's past spending mix reflects how it behaved under past rules, not how it would respond to this new mechanism that pays a return on capital during the plan term while applying productivity pressure only to OM&A. If anything, a utility that has historically relied on OM&A has more room to shift spending toward capital. Second, the Company states that "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." But the non-wires and DER alternatives that the IDSP and the Authority's NWS process are designed to evaluate exist precisely because some grid needs can be met with either a capital investment or an operating solution. Third, the Company contends that the prospect of a future prudence review "eliminates any perceived financial benefit for the Company to 'over invest' today". It does not. A prudence review asks only whether the Company's choice was reasonable when made. If the Company chooses a reasonable capital project when a lower-cost operating or non-wires solution would have met the same need, that project passes review and customers pay for it in full. Under the F-Factor, they would also pay a return on it from the day it enters service, before any review occurs. A prudence review screens out

unreasonable spending, not unnecessary spending, so it cannot stop the Company from choosing the more expensive option.

C. Timeline of the PBR Proceedings Relative to Eversource's Rate Case Filing

Q. PLEASE DESCRIBE THE TIMELINE OF THE RE01, RE02, AND RE03 REOPENER PROCEEDINGS RELATIVE TO EVERSOURCE'S RATE CASE FILING.

A. A timeline sequencing the events and dates related to the PBR docket and its reopeners, as well as Eversource's rate case application, is provided as Appendix B.

Q. WHEN DID EVERSOURCE FILE ITS PROPOSED PBMRP RELATIVE TO THE AUTHORITY'S PBR PROCEEDINGS?

A. Eversource filed its rate case proposing a first-generation PBMRP on July 14, 2026, including a capital funding mechanism and a PIMs portfolio, before the Authority issued final decisions in RE01, RE02, or RE03.[47]

The timing of the filing was the Company's decision. Eversource's last base distribution rate case was decided more than eight years ago, in April 2018, and the three-year rate plan approved in that case expired on April 30, 2021.[48] The Company has operated under those rates for more than five years since that plan ended. Nothing precluded the Company from proposing a PBR plan before the

[47] Application, at page 1.
[48] Id., at page 4 & n. 4.

reopeners concluded, and the Authority has said it will consider this plan.[49] But a proposal filed before the statewide framework is final must stand on its own merits, and the Company's does not. As I explain in Sections IV through VII, it would not produce just and reasonable rates or advance the Phase 1 priority outcomes, and the Company has not shown that its alternatives would better serve customers. The status of the reopeners also counsels against adopting any multi-year rate plan in this case. A multi-year plan would fix the Company's revenue mechanisms for four years. If the Authority adopts one now, it would be setting the terms of Eversource's first PBR plan before deciding the framework that plan is meant to implement, and before the Company has filed a plan, reviewed by stakeholders, that could support its capital forecast. Any differences between the approved plan and the final framework would then persist for the full plan term. That is why, as I explain in Section IX, any PBR mechanisms adopted here should follow the framework developed in the reopeners, and capital funding beyond the first rate year should wait until the Company has refiled its Targeted System Performance Plan in a form that conforms to the IDSP requirements in RE03 PFD No. 2.

[49] Motion No. 43 Ruling.

III. EVERSOURCE BEARS THE BURDEN OF DEMONSTRATING THAT ITS PROPOSED PBMRP IS JUST AND REASONABLE AND IN THE PUBLIC INTEREST

Q. WHO BEARS THE BURDEN OF PROOF IN THIS PROCEEDING?

A. Connecticut law places on the public service company the burden of proving that its proposed rates are just and reasonable. Conn. Gen. Stat. § 16-22. That burden applies to each element of the Company's proposed PBMRP, including its revenue adjustment mechanism, capital funding mechanism, and PIMs portfolio, because each of those mechanisms contributes to the determination of what customers will pay over the plan term. If the record does not demonstrate that a proposed mechanism will produce just and reasonable rates, the Company has not carried its burden, The Authority has explained that this burden "addresses the information imbalance by imposing an affirmative obligation on the utility to present sufficient evidence to support its proposed rate amendment."[50]

Q. WHAT DOES IT MEAN FOR RATES TO BE JUST AND REASONABLE?

A. For rates to be just and reasonable, customers should pay enough to support safe, reliable service and the utility a reasonable opportunity to earn a fair return on its prudent investment, one sufficient to maintain its financial integrity and attract capital, but no more than that.[51] Customers should only pay for costs that were

[50] RE01 PFD, at page 44 n. 36.

[51] This reflects the principle in Conn. Gen. Stat. § 16-19e(a)(4) that rates be "sufficient, but no more than sufficient," to allow a utility to cover its operating and capital costs, attract needed capital, and maintain its financial integrity, while protecting the public interest. *See also Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

prudently incurred. Appropriately set rates encourage the utility to manage its costs efficiently. And the risks of higher-than-expected costs are shared fairly between the utility and its customers, instead of falling mostly on customers. Connecticut's ratemaking principles reflect these principles.[52]

A multi-year rate plan makes these protections more important. Because it sets rates for several years based on formulas and forecasts, the Company must show that the rates its plan produces in every year of the term are sufficient, but no more than sufficient, reflect only prudently incurred costs, encourage efficient cost management, and share the risk of higher than expected costs fairly between the Company and its customers. The Company's proposal falls short because it: (1) authorizes capital recovery up to the Company's own forecast, roughly 40 percent above its 2021–2025 average spending;[53] (2) collects a return on new capital, estimated at $124.1 million over the plan term, before the Authority has found that capital prudent[54]; (3) applies productivity pressure to operating costs only, so it continues to favor capital spending over efficiency[55]; and (4) places most of the risk on customers, while putting only about $10 million a year of the Company's earnings at stake for performance.[56]

A multi-year rate plan sets rates for several years based on formulas and forecasts established at the outset, rather than on costs the Authority has examined. Once the

52 Conn. Gen. Stat. § 16-19e(a)(4)–(5)).
53 OCC-424, at Attachment 1.
54 OCC-423, at pages 4, 7, 10.
55 Exhibit CLP-PBR-1, at pages 42, 56, 64, 68.
56 Id., at pages 66-67; Exhibit CLP-ELP-1, at page 115.

plan is approved, customers lose the protection of a full review of the Company's costs for the length of the plan term. The Company must show not only that its going-in rates are just and reasonable, but that the rates its mechanisms will produce in each year of the plan will be as well.

Q. WHAT MUST THE COMPANY DEMONSTRATE TO CARRY THAT BURDEN?

A. At a minimum, I would expect the Company to demonstrate that its proposed plan:

(1) will produce just and reasonable rates over the full plan term, consistent with Conn. Gen. Stat. § 16-19e;

(2) allocates risk appropriately between the Company and its customers, and contains costs rather than simply providing for their recovery;

(3) advances the standards, metrics, and priority outcomes the Authority adopted in its Phase I Decision to implement the Take Back Our Grid Act (Conn. Gen. Stat. §§ 16-244aa, 16-19a(b)); and

(4) where it departs from the designs the Authority developed in Docket No. 21-05-15 and its reopeners explains, with supporting evidence, why its alternative serves those priority outcomes at least as well. The Proposed Final Decisions are not binding, and departing from them is not itself a deficiency, but they are the most developed analysis in the record of how those outcomes can be achieved. A departure from them without that explanation leaves the Authority without a basis for finding that the alternative will produce just and reasonable rates.

As I explain in Sections IV through VIII, the Company has not made any of these showings.

Q. WHAT DOES THE TAKE BACK OUR GRID ACT REQUIRE THE AUTHORITY TO DO WITH RESPECT TO PERFORMANCE-BASED REGULATION?

A. The Take Back Our Grid Act charges the Authority with adopting a PBR framework that (1) establishes standards and metrics for electric distribution company performance; (2) identifies how those standards apply to rate determinations under Conn. Gen. Stat. §§ 16-19a and 16-19e; and (3) identifies the specific mechanisms — multiyear rate plans ("MRPs"), earnings sharing mechanism ("ESM"), revenue decoupling mechanism ("RDM"), PIMs — that align utility performance with those standards. Conn. Gen. Stat. § 16-244aa(b). The Take Back Our Grid Act assigns responsibility for developing PBR standards, metrics, and mechanisms to the Authority, through a single proceeding that applies to each electric distribution company (Public Act 20-5, § 1(b) ("the Public Utilities Regulatory Authority shall initiate a proceeding to investigate, develop and adopt a framework for implementing performance-based regulation of each electric distribution company")).

Q. HOW SHOULD THE AUTHORITY DETERMINE WHETHER THE COMPANY'S PROPOSAL SERVES THE PUBLIC INTEREST?

A. The Authority has already defined what a PBR framework must accomplish in Connecticut. Its April 2023 Phase I Decision adopted the four regulatory goals,

five foundational considerations, and nine priority outcomes that govern all subsequent PBR work.[57] Those goals and priority outcomes were adopted in 2023, and they provide an objective measure of whether a proposed plan serves the public interest that does not depend on the timing of final decisions in the reopeners. I evaluate each of the Company's proposed mechanisms against them.

Q. WHAT ROLE SHOULD THE RE01, RE02, AND RE03 PROPOSED FINAL DECISIONS PLAY IN THE AUTHORITY'S EVALUATION?

A. The Proposed Final Decisions are not final orders and do not bind the Company or the Authority. But they are the only PBR design for Connecticut developed on a full, multi-year, multi-stakeholder record, and the Company participated actively in developing that record, even where it disagreed with the outcome. They reflect the Authority's considered judgment about how the mechanisms of a PBR framework should fit together to advance the priority outcomes. The Company itself treats RE01 as its reference point, describing its proposal as "generally consistent with the framework discussed in Docket No. 21-05-15RE01".[58] The Proposed Final Decisions are therefore the best evidence in this record of what a just and reasonable PBR design for Connecticut looks like. Where the Company departs from them, it should explain why its alternative serves the priority outcomes at least as well. While the proposed final decisions are not final orders, they were developed in the context of the goals,

[57] RE03 PFD No. 2, at page 2 & nn. 2-4 (citing Docket No. 21-05-15, April 26, 2023 Decision (Phase 1 Decision), at pages 10-19).

[58] Exhibit CLP-PBR-1, at page 60.

considerations, and outcomes from the April 2023 Phase I Decision, which sets out the goals and outcomes against which the Authority evaluates PBR proposals. To be clear, I do not contend that the Company's proposal should be rejected because it differs from the Proposed Final Decisions. As I show below, it should be rejected on its merits: it would not produce just and reasonable rates, it would not advance the priority outcomes adopted in the Phase 1 Decision, and the Company has not shown otherwise.

Q. THE AUTHORITY HAS RULED THAT IT WILL CONSIDER THE COMPANY'S PBR PLAN IN THIS PROCEEDING. DOES THAT RULING AFFECT YOUR ANALYSIS?

A. No, it does not affect my analysis. I do not dispute that the Company may propose a PBR plan in this proceeding or that the Authority will consider it. The Authority found that "nothing precludes CL&P from proposing PBR in the above-referenced proceeding and nothing precludes PURA from considering it," and that it "will consider the Company's PBR plan in this proceeding".[59] Considering a proposal is not the same as approving it. Consideration means evaluating the plan on its merits, with the burden of proof on the Company. That is the evaluation my testimony provides, and it shows that the Authority should not approve the Company's proposal.

[59] Motion No. 43 Ruling, at page 2.

IV. IV. EVERSOURCE HAS NOT SHOWN THAT ITS REVENUE ADJUSTMENT AND CAPITAL FUNDING MECHANISMS ARE JUST AND REASONABLE

A. Revenue Adjustment Mechanism / Revenue Cap Formula Design

Q. WHAT DID THE AUTHORITY PROPOSE IN THE RE01 2025 PFD?

A. Issued July 14, 2025, the RE01 PFD proposed to adopt a Revenue Cap Formula (the "I-X-S-Z+CT" formula) that applies to the Company's total revenue requirement, meaning both capital and OM&A costs.[60] The X-Factor in that formula would be derived from a Total Factor Productivity ("TFP") study covering both capital and OM&A productivity trends. Incremental capital investment would be funded through a separate mechanism called the "CT-Bar," which (1) is tied to the Company's IDSP and Capital Plan, (2) excludes any return on investment until the investment is found prudent in a later rate case, and (3) is reconciled downward only.[61]

Q. WHAT ARE THE DIFFERENCES BETWEEN THE RE01 PFD AND EVERSOURCE'S PROPOSAL?

A. Eversource is proposing an "I-X" revenue adjustment mechanism that applies only to OM&A costs. Capital costs are addressed through a separate mechanism based on an approved forecast of capital investment, which recovers the lesser of

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[60] In the RE01 Proposed Revenue Cap Formula, "I" is an inflation index, "X" a productivity factor, "S" a stretch factor or customer dividend, "Z" a factor for unusual costs outside the utility's control, and "CT" incremental capital funding through the CT-Bar and capital trackers. RE01 PFD, p. 20.

[61] RE01 PFD, at pages 27, 31-41 & App. A, §§ A.6–A.7.

the forecasted capital revenue requirement or the revenue requirement associated with actual plant placed in service.[62] The following tables identifies the differences between the revenue adjustment mechanisms proposed in the RE01 PFD and those proposed in Eversource's PBRMP proposal.

Comparison of Eversource's Proposed Revenue Adjustment Mechanisms to the RE01 Proposed Final Decision[63]

Component	RE01 Proposed Final Decision (July 14, 2025)	Eversource Proposal (Docket No. 26-05-10)	Comparison
Plan term	Four-year multi-year rate plan, with the next rate case filed during Rate Year 4. *(pp. 8–9)*	Four-year plan term with a four-year stay-out period. *(Exh. CLP-ELP-1, p. 84; Exh. CLP-PBR-1, p. 61)*	Consistent
Stay-out	MRP may be conditioned on the utility deferring any rate amendment until Rate Year 4. If the utility declines, the MRP does not take effect and rates are set for the first rate year only. *(p. 10)*	States it "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," and will commit only after reviewing the final decision. *(CLF-AC-002, p. 9; Exh. CLP-ELP-1, pp. 98–99)*	Departs: stay-out conditioned on a return the PFD excludes
Revenue cap formula scope	I-X-S-Z+CT Revenue Cap Formula applied to the total revenue requirement (capital and OM&A). *(pp. 20–21)*	I-X formula applied to OM&A only; capital recovered through a separate forecast-based F-Factor. *(Exh. CLP-ELP-1, p. 85; Exh. CLP-PBR-1, p. 42)*	Departs: no formula discipline on capital

62 Exhibit CLP-PBR-1, at pages 1, 41-42, 59, 69-71.

63 RE01 page citations are to Docket No. 21-05-15RE01, Proposed Final Decision (July 14, 2025). Eversource citations are to the Company's July 14, 2026 filing in Docket No. 26-05-10 and its discovery responses.

Component	RE01 Proposed Final Decision (July 14, 2025)	Eversource Proposal (Docket No. 26-05-10)	Comparison
X-Factor	Based on a Total Factor Productivity study covering capital and OM&A productivity trends. *(pp. 21–22)*	X-Factor of −0.03% (OM&A partial factor productivity trend), applied to OM&A only. *(Exh. CLP-PBR-1, pp. 42, 64)*	Departs: negative X-Factor; OM&A only
S-Factor / Consumer Dividend	Always positive; set in each rate case, which may use a simple tiered approach that assigns a larger S-Factor to less efficient utilities. *(pp. 22, 59 & n.50)*	0.30% Consumer Dividend floor, rising only if the Company outperforms its own inflation-adjusted O&M benchmark. Not derived from its consultant's benchmarking, which shows OM&A 16.4% above benchmark (2021–2024). *(Exh. CLP-PBR-1, p. 64; OCC-539(b), p. 2; OCC-559, pp. 3–4)*	Departs: does not scale with relative inefficiency
Z-Factor	Materiality threshold of 0.75% of annual revenue requirement. *(pp. 25–26)*	Threshold of 0.5% of total distribution revenue (≈$10M), which the Company calls "more closely aligned" with other jurisdictions than the PFD's "unnecessarily high" 0.75%. *(Exh. CLP-ELP-1, p. 100; OCC-430, pp. 1–2)*	Departs: lower threshold; different base
Capital funding mechanism	CT-Bar tied to the utility's Capital Plan (including IDSP-supported investments). Recovers only depreciation, property tax, and gross earnings tax; no return until found prudent in a later rate case; downward-only reconciliation. *(pp. 31–41, 36, 59)*	F-Factor based on the Company's approved capital forecast, reconciled annually, recovering the lesser of forecast or actual revenue requirement. Includes cost of capital (≈$124.1M over plan term), cost of removal, and modified depreciation. *(Exh. CLP-ELP-1, p. 101; OCC-435, p. 1, Table 1)*	Departs: return collected before prudence; cap set by Company forecast

Component	RE01 Proposed Final Decision (July 14, 2025)	Eversource Proposal (Docket No. 26-05-10)	Comparison
Earnings sharing	Asymmetrical (upside-only) ESM, 50/50 sharing, no dead bands. *(pp. 46–48)*	Upside-only 50/50 ESM, but the customer share is passed directly to customers rather than first offsetting environmental remediation and catastrophic storm balances. *(Exh. CLP-ELP-1, p. 98; Exh. CLP-PBR-1, p. 65)*	Largely consistent; customer share applied differently
Performance mechanisms and IDSP	Apply whether or not a utility accepts an MRP; declining an MRP "does not exempt the EDC" from them. *(p. 10)*	PIMs proposed "contingent upon the approval of the proposed PBMRP"; penalty pool capped at 0.5% of distribution revenue (≈$10M/yr) and incentives at ≈$5M/yr. *(Exh. CLP-ELP-1, pp. 50, 115; Exh. CLP-ELP-3, p. 2; Exh. CLP-PBR-1, p. 66)*	Departs: accountability conditioned on plan approval
ROE and PIMs	No ROE adjustment for PBR mechanisms, but the Authority will consider them in evaluating utility-specific risk. *(pp. 42, 59)*	Requests 10.25% ROE plus up to ≈$5M/yr in PIM incentives. *(Exh. CLP-ELP-1, p. 82; Exh. CLP-ELP-3, p. 2)*	Risk/reward of PIM portfolio should inform ROE
Efficiency carryover	Declined at this time; may be considered in future rate plans. *(pp. 43, 59)*	None proposed (not addressed in Exhs. CLP-ELP-1 or CLP-PBR-1).	Consistent

Q. Q. HAS THE COMPANY SHOWN THAT ITS PROPOSED X-FACTOR AND REVENUE CAP FORMULA WILL CONTAIN COSTS?

A. No. A revenue cap can contain costs only if it applies to the full revenue requirement. Otherwise, costs simply migrate to the part of the formula the cap does not reach. The Company applies its X-Factor to OM&A costs only and

recovers capital separately as plant is placed in service. [64] As a result, most of the Company's revenue requirement would face no productivity discipline at all. The RE01 PFD instead applies the revenue cap formula to the total revenue requirement, covering both capital and OM&A, with an X-Factor derived from a total factor productivity ("TFP") study that measures the productivity of both types of inputs.[65]

The Company's X-Factor also points the wrong way. At −0.03 percent, it would allow OM&A revenues to grow faster than inflation.[66] That is the opposite of what a productivity factor is meant to do, particularly for a utility whose OM&A costs its own consultant found to be 31.5 percent above benchmark in 2024.[67] The Company's study also does not meet the RE01 PFD's proposed requirement to use customer count, delivered energy, and peak demand as outputs. It only uses customer count.[68]

If the Authority adopts a revenue cap formula, it should apply that formula to the Company's total revenue requirement, with an X-Factor based on a TFP study that meets the RE01 PFD's requirements. The Authority should not approve a negative X-Factor based on a study that does not meet those requirements.

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64 CLF-AC-005, at page 2; Exhibit CLP-PBR-1, at pages 42, 68.
65 RE01 PFD, at pages 20-22 & n.19, 25.
66 Exhibit CLP-PBR-1, at pages 42, 64.
67 Id., at page 56.
68 RE01 PFD, at page 25; Exhibit CLP-PBR-1, at pages 34-35, 38, 63.

B. Capital Funding Mechanism: The CT-Bar Compared to Eversource's Forecast-Based Mechanism

Q. WHAT CAPITAL FUNDING MECHANISM DID THE AUTHORITY PROPOSE IN THE 2025 RE01 PFD, AND WHY?

A. The Authority included in the RE01 PFD the CT-Bar, a capital funding mechanism tied to the electric distribution company's Capital Plan (including IDSP-supported grid investments), recovering only depreciation, property tax, and gross earnings tax expense for incremental capital additions, expressly excluding any return on investment until the capital investment is found prudent and used and useful in a later rate case, and subject to downward-only reconciliation. Notably, the PFD rejected Eversource's own "K-Bar" proposal, which used a historical average of capital spending, rather than IDSP-linked forward planning, and would have included a return on investment.[69] The Company confirmed that the K-Bar relied on historical plant additions and inflation and included the cost of capital.[70]

Q. WHAT CAPITAL FUNDING MECHANISM IS EVERSOURCE PROPOSING IN THIS RATE CASE?

A. Eversource here proposes a capital funding mechanism, which it calls the "F-Factor," based on "an approved forecast of capital investment established in this proceeding," with annual reconciliation in the revenue adjustment mechanism

[69] RE01 PFD, at page 31 & n. 30.
[70] CLF-AC-003, at pages 1-2.

("RAM") proceedings. Recovery would be limited to "the lesser of the approved forecasted capital revenue requirement or the revenue requirement associated with actual plant placed in service".[71] The Company describes the F-Factor as tracking the CT-Bar "as close as possible," except that it (1) includes the cost of capital on new plant additions during the plan term, (2) includes the cost of removal, and (3) changes how depreciation is calculated.[72] Eversource witness Ms. Frayer supports the design by reference to capital mechanisms approved in Massachusetts and British Columbia.[73] Each of these changes increases the revenue the Company would collect during the plan term relative to the CT-Bar. The first is the most significant: by the Company's own estimate, including the cost of capital would add $124.1 million over the plan term, and it would allow the Company to collect a return on new plant before the Authority has found that investment prudent.[74] Ms. Frayer's Massachusetts example is a K-Bar mechanism, which relies on historical capital investment rather than a utility-prepared forecast, and which the Massachusetts Department of Public Utilities approved "subject to cost-control and prudency measures designed to protect customers from over- or mis-investment."[75] The Authority considered a K-Bar in RE01 and did not propose to

[71] Exhibit CLP-PBR-1, at page 68.
[72] OCC-423, at pages 4, 10.
[73] Exhibit CLP-PBR-1, at pages 68-70.
[74] OCC-423, at page 7.
[75] Exhibit CLP-PBR-1, at page 69.

adopt it.[76] Neither example supports collecting a return on forecast capital before prudence is established.

Q. HOW ARE THE IDSP AND THE CT-BAR INTENDED TO WORK TOGETHER?

A. The IDSP and the CT-Bar were designed as two halves of one process. The IDSP requires the utility to identify what the grid needs and why. For example, where capacity is constrained, where reliability needs attention, and where hosting capacity must grow to accommodate distributed energy resources. Through the Joint Working Group, public engagement, and the IDSP review docket, the Authority and stakeholders would test and agree on those needs *before* the rate case.[77] The IDSP establishes that a grid need exists. It does not approve the cost of any particular way of meeting that need. The quantitative review, determining whether the Company's actual spending was prudent, comes later, in the rate case. As the Authority explained, the IDSP "can provide the basis for evaluating the prudence of grid investments under either a traditional rate filing or a proposed MRP under a PBR framework".[78] The CT-Bar completes that design by withholding any return on new capital until that prudence finding is made.[79]

For example, an IDSP ruling might confirm that additional hosting capacity is needed in a particular area and that investment should be made there. That finding

[76] RE01 PFD, at pages 31 n. 30, 35 n. 32.
[77] RE03 PFD No. 2, at pages 17-24, 69-75.
[78] Id., at pages 8-9.
[79] RE01 PFD, at pages 31-41.

does not settle whether the business decisions the Company makes to deliver that capacity are reasonable: its choice between a traditional wires upgrade and a non-wires alternative, its procurement, its project design, or its cost management. Those business decisions are what a prudence review scrutinizes. The question in the rate case is not whether an investment needed to be made, which the IDSP would have already answered, but whether the Company made it wisely.

Q. HOW DOES THE ALLOCATION OF RISK UNDER THE COMPANY'S FORECAST-AND-RECONCILE MECHANISM COMPARE TO THE CT-BAR PROPOSED IN RE01?

A. Under the CT-Bar, the utility recovers depreciation, property tax, and gross earnings tax on new capital during the plan term, but it earns no return on that capital, and accrues no carrying charges, until the Authority finds the investment prudent and used and useful in the next rate case.[80] The Authority designed it that way deliberately. The CT-Bar "is not intended to serve as an exception to the well-established principle that utilities may only earn a return on prudently invested capital".[81] Under traditional cost-of-service regulation, absent a capital tracker, a utility that places new plant in service between rate cases recovers nothing on that investment, neither a return nor depreciation or taxes, until the Authority reviews its prudence in the next rate case and adds it to rate base. The CT-Bar is more generous than that. It lets the utility recover depreciation and taxes on new capital

[80] Id., at pages 36-39.
[81] Id., at page 33.

during the plan term, which it "would not ordinarily be permitted to obtain under typical ratemaking principles".[82] What the CT-Bar withholds until prudence is shown is the return, the part of the revenue requirement that rewards capital spending.

The Company's F-Factor allocates risk differently. Each year, customers would pay the full revenue requirement on the Company's new capital, including a return, beginning with an allowance based on the Company's forecast. The Authority would review whether those investments were prudent only in the following year's reconciliation, after customers had already paid.[83] For example, if the Company places a new substation project in service in 2027, customers would begin paying depreciation, taxes, and a return on it through the F-Factor that year. Prudency would be determined in the 2028 reconciliation. Under the CT-Bar, customers would pay only depreciation and taxes on that project during the plan term, and the Company would earn no return on it until the Authority found it prudent in the next rate case.

Ms. Frayer points out that the Company bears the risk of spending above the approved forecast.[84] The converse is also true: up to the forecast, the Company bears little risk at all. Customers would begin paying the full revenue requirement on new plant, including a return, as soon as it enters service. The risk that any of

82 Id.
83 Exhibit CLP-PBR-1, at pages 68, 71; OCC-423, at pages 10-11.
84 Exhibit CLP-PBR-1, at pages 70-71.

that spending is imprudent would rest with customers until a later reconciliation.[85] But that protection is only as good as the forecast. If the Company prepared its forecast without the guardrails baked into the IDSP process, the Authority would not have an independently reviewed plan against which to test it (see Section V). Under the F-Factor, customers would pay a return on new plant as soon as it enters service, and any finding that a choice was imprudent would come after that return had been collected. The Company states that it does not view the F-Factor as providing a return before prudence review, because amounts collected on investment later found imprudent would be returned to customers through its downward-only reconciliation. But it confirms that the F-Factor allowance "does include the cost of capital, including return on equity investment," on capital additions the Authority has not yet reviewed, and that its proposal is "intentionally inconsistent" with the CT-Bar on this point.[86] Customers would pay that return first, and would be refunded only if the Authority later finds the investment imprudent. By the Company's own estimate, the cost of capital alone would add $124.1 million over the plan term relative to the CT-Bar.[87] The objective of a PBR capital funding mechanism is to protect customers from imprudent spending and to reward the utility only when it spends prudently, not to shift substantial risk from utility shareholders onto ratepayers by paying a return before prudence is shown.

85 OCC-423, at pages 10-11.
86 CLF-AC-004, at pages 1-2.
87 OCC-423, at page 7.

Q. CAN YOU ILLUSTRATE THE DIFFERENCES BETWEEN THESE TWO APPROACHES?

A. Yes. Consider a household deciding whether to replace a car. One spouse proposes using the family's savings to buy a new car, and the other agrees that a new car is needed. That agreement is the equivalent of the IDSP: it establishes the need, not the price. The first spouse then goes out and buys a large luxury SUV. When the couple later sits down to reconcile their spending, they realize that a reliable, fuel-efficient sedan would have met the family's needs at far lower cost. By then the savings are spent, the SUV lost a large share of its value the moment it left the lot, and the household is worse off than if the less expensive option had been purchased. Under PURA's proposed IDSP and the CT-Bar, the household agrees that a new car is needed, but the purchase is reviewed before the household pays for it in full. If the review shows the luxury SUV was the wrong choice, the extra cost of that decision falls on the spouse who made it, not on the family's savings. Under the Company's forecast-and-reconcile proposal, the spouse making the purchase proposes the budget, the household agrees in advance to cover whatever is spent up to that budget, and payments begin as soon as the car is chosen. The only automatic check is whether the spouse spent *more* than the budget they wrote, and not whether the purchase itself was a sensible one. Whether an SUV was the right choice is examined only after the household has already begun paying for it.

Q. HOW HAS THE COMPANY EXPLAINED ITS DEPARTURE FROM THE CT-BAR?

A. The Company's explanation only reflects its own financial interests. It calls the CT-Bar's exclusion of the cost of capital "a non-starter from a policy perspective" and states that, without that return, it could not commit to a stay-out.[88] Asked how its approach would produce customer savings or improve affordability compared with including capital in the RE01 revenue cap, the Company offered only general statements about the benefits of planned, systematic investment, which it acknowledged are "difficult to define in terms of the overall cost trends".[89] The Company has not shown that the proposed F-Factor would produce lower rates, better performance, or any other benefit to customers, compared with the CT-Bar. Its principal argument is that the CT-Bar "did not reflect the economic reality that financing costs are incurred when investments are made and placed in service".[90] That is equally true under traditional cost-of-service regulation, where new plant earns no return until the next rate case, and it does not explain how customers would be better off under the F-Factor. An explanation of why a mechanism is better for the utility's shareholders does not carry the Company's burden of showing that the resulting rates are just and reasonable. Under the Company's plan, those rates would be set by formula for four years. OM&A revenues would escalate each year under its I-X formula, and capital revenues would rise with the F-Factor up to the

88 OCC-423, at pages 3, 7-8.
89 Id, at pages 12-13.
90 CLF-AC-004, at page 2.

Company's own forecast. The Company has not shown that either formula produces rates that are just and reasonable in any year of the plan, let alone all four.

Q. **WOULD WITHOLDING THE RETURN ON NEW CAPITAL UNTIL PRUDENCE IS ESTABLISHED DENY THE COMPANY A REASONABLE RETURN?**

A. No. The Company is entitled to an opportunity to earn a reasonable return on capital that is prudently invested, and the CT-Bar would preserve that opportunity. A utility that invests prudently earns its full return once the investment is reviewed and placed in the rate base. The CT-Bar would affect the timing of that return, not whether the Company would earn it. The deferral would carry a time-value cost for the Company, but that is the same regulatory lag utilities experience under traditional cost-of-service regulation, where a new plant earns no return until prudence is reviewed in a rate case. The CT-Bar is more generous than traditional cost-of-service regulation, because it lets the Company recover depreciation and taxes on new plant during the plan term, before any prudence review. Withholding the return until prudence is established is the trade the Authority designed into the CT-Bar in exchange for that earlier recovery. The Company's own history shows that it can operate under this kind of regulatory lag. Its last base rate case was decided in April 2018, and the rate plan from that case expired in 2021.[91] Since then, the Company has added roughly $3.3 billion in net utility plant without

[91] Application, at page 4 & n. 4; see Docket No. 17-10-46, April 18, 2018 Decision.

earning a return on that plant through base rates until this rate case.[92] The Company's witness has acknowledged that rates based on historical plant additions gave the utilities "an opportunity, if they could manage their costs under those revenues, to earn their authorized return."[93] The Company argues that, without a return on new capital, it would have to cut O&M expense by roughly 23 percent by Rate Year 4 to earn its authorized return, and that it would instead file rate cases as often as every 18 months.[94] But it has not reconciled that position with its own experience of adding $3.3 billion in plant since 2021 without a capital tracker, or explained why the CT-Bar, which would provide more interim revenue than the Company has received since 2021, would leave it worse off.

Q. IF THE AUTHORITY DECIDES TO ALLOW A RETURN ON NEW CAPITAL DURING THE PLAN TERM, WHAT CONDITIONS SHOULD APPLY?

A. If the Authority decides to allow a return on new capital during the plan term, that approach could be reasonable from a policy perspective only if two conditions keep the risk of imprudent spending on the Company first.

First, recovery should be capped at a capital plan reviewed through the IDSP process rather than at the Company's own forecast. Second, any return collected should be subject to refund to customers, with carrying costs, upon a finding of

92 Application, at page 3.
93 Docket Nos. 21-05-15RE01, 21-05-15RE02, and 21-05-15RE03, Technical Meeting Transcript (May 21, 2025), at pages 103-104 (D. Horton).
94 CLF-AC-001, at pages 9-10.

imprudence.[95] The F-Factor does not meet the first condition: its cap is the Company's own forecast, which has not been reviewed through an IDSP. On the second, the Company states that amounts collected on investment later found imprudent would be returned to customers through its downward-only reconciliation, but it identifies carrying charges only for investment the Company does not place in service, not for investment found imprudent.[96] If the Authority allows a return during the plan term, it should require that any refund for imprudent investment include carrying costs.

Q. WHAT DOES THE RECORD SHOW ABOUT THE COMPANY'S FORECAST CAPITAL SPENDING TRAJECTORY?

A. The Company forecasts a sustained increase in capital spending well above its historical levels. Its total capital expenditures are forecasted to grow from $551.0 million in 2025 (actual) to $884.0 million in 2031 (planned), an increase of approximately 60% (OCC-424, Attachment 1).[97] The forecast rises in every year, reaching $690.0 million in 2027 and $884.0 million in 2031. By comparison, the Company's actual capital expenditures averaged approximately $575 million per year from 2021 through 2025. Its highest year in that period was $684.5 million in 2023.[98] Every forecast year from 2027 through 2031 exceeds the Company's highest actual year in the most recent five-year period. The largest driver in this

95 See Docket Nos. 21-05-15RE01 and 21-05-15RE02, Written Exceptions of the Advocates on Proposed Final Decisions (Aug. 15, 2025), at page 2.
96 CLF-AC-004, at pages 1, 3.
97 OCC-424, Attachment 1.
98 Id.

cost increase is reliability spending, which is forecasted to more than double, from $164.3 million in 2025 to $377.7 million in 2031.[99]

Reliability investment may be needed, but it cannot be assumed. The question is whether the Company has provided sufficient justification for its forecasted level of investment. It has not. The Company has not reconciled its forecast against its own past spending or explained why these needs could not be met at historical levels.

Ms. Frayer testifies that a formula grounded in historical trends may not produce an adequate revenue trajectory when a utility "is expected to undertake capital investments at a pace significantly greater than historical levels".[100] Under the Company's proposed capital funding mechanism, this forecast becomes the cap on capital recovery for the plan term.[101] The Authority, if it adopts Eversource's capital funding mechanism proposal, would therefore be authorizing capital recovery up to a level roughly 40 percent above the Company's 2021–2025 average spending.[102]

99 Id.

100 Exhibit CLP-PBR-1, at pages 23–24.

101 Id, at page 68.

102 The Company's forecast capital expenditures for 2027–2031 average $797 million per year ($3.985 billion ÷ 5). Actual capital spending for 2021–2025 averaged $574.6 million per year. The difference, $222.4 million, is about 39 percent of the historical average. These figures are in nominal dollars. Adjusting for inflation would reduce the percentage difference but would not eliminate it.

Q. HAS THE COMPANY DEMONSTRATED THAT FUNDING CAPITAL AT ITS OWN FORECAST WILL PRODUCE JUST AND REASONABLE RATES?

A. No. Under the Company's proposal, its capital forecast becomes the cap on capital recovery for the plan term, so the reasonableness of that forecast is central to whether the resulting rates are just and reasonable. The Company has not made that showing. Funding capital from a multi-year forecast is reasonable only when that forecast has been vetted. The IDSP process was designed to provide this. It tests grid needs, forecasting assumptions, and alternatives with stakeholders and the Authority before a rate case.[103] The Company's forecast has not been subject to anything approaching such rigorous review. It is the Company's own projection of what it intends to spend, and it cannot justify locking in four years of capital recovery (see Section V).[104] While the Company's forecast can be scrutinized in this rate case, that does not substitute for the review process contemplated in the IDSP Proposed Final Decision. For example, information obtained through discovery can test the Company's cost estimates, but a contested rate case is not designed to test grid needs, forecasting assumptions, and non-wires alternatives

103 RE03 PFD No. 2, at pages 8-9, 17-24, 69-75.

104 In RE01, Eversource also requested a "G-Factor" to increase revenues automatically for load and customer growth. The Authority declined this request in its Proposed Final Decision, with a proposed finding that going-in rates, the I-Factor, and the IDSP-linked CT-Bar already account for growth, and that a G-Factor "would undermine the priority outcomes of Business Operations and Investment Efficiency and Affordability by including additional automatic revenue requirement increases." (RE01 PFD, at pages 27-28). The Company does not re-propose a G-Factor here, but because it proposes neither the CT-Bar nor an IDSP, the growth assumptions in its capital forecast would be funded without the planning review the Authority relied on in rejecting one.

with stakeholders over a ten-year planning horizon, as the IDSP was designed to do.[105] Ms. Frayer recognizes that it is "common to hear" that forecast-based approaches present "informational asymmetry between the regulator and the regulated firm," and that approving utility forecasts "is nonetheless information intensive, and may become complex and contentious".[106] The Authority has explained that the utility's statutory burden of proving that its proposed rates are just and reasonable exists to address that kind of information imbalance, by requiring the utility to present sufficient evidence to support its proposal.[107] By the Company's own estimate, including the cost of capital in the F-Factor would add $124.1 million over the plan term compared with the CT-Bar.[108] A mechanism that would authorize capital recovery up to roughly 40 percent above the Company's recent historical average and pay a return on that capital before prudence is established, is simply not just and reasonable based on this record.

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105 In a contested rate case, meaningful participation generally requires legal counsel, expert witnesses, and the capacity to conduct discovery on a compressed litigation schedule. Many stakeholders with an interest in distribution planning cannot support that commitment. The IDSP process proposed in RE03 PFD No. 2 is designed for broader engagement. It would require the Company to convene at least four Joint Working Group sessions before each IDSP filing, with agendas and background materials circulated in advance. It would also establish a data-sharing protocol so stakeholders can review planning data, and add a public engagement phase for municipal officials, environmental justice communities, and customers. (RE03 PFD No. 2, at pages 18-21).

106 Exhibit CLP-PBR-1, at pages 13-14.

107 RE01 PFD, at pages 44 n.36.

108 OCC-423, at page 7.

C. Plan Term, Stay-Out Provisions, and Going-In Rate Mechanics

Q. HOW DOES EVERSOURCE'S PROPOSAL ON PLAN TERM, EARNINGS SHARING, AND THE Z-FACTOR COMPARE TO THE RE01 2025 PROPOSED FINAL DECISION?

A. Eversource's filing shares some similarities with RE01 in these areas, alongside notable differences: (1) both propose a four-year plan term; (2) both include an Earnings Sharing Mechanism generally along the lines of RE01's asymmetrical, upside-only 50/50 sharing structure, although Eversource's version changes how the customer share of overearnings is applied; and (3) both propose a Z-Factor, but at a materially different threshold with 0.5% of distribution revenue in Eversource's proposal, compared to 0.75% of annual revenue requirement in the RE01 2025 PFD. Eversource advocated a 0.5 percent threshold in RE01; the Authority considered that proposal and proposed 0.75 percent.[109] The Company notes that the other jurisdictions the RE01 PFD cites use thresholds between 0.2 and 0.5 percent.[110]

[109] RE01 PFD, at pages 24-26.
[110] CLF-AC-001, at pages 12-13.

V. EVERSOURCE HAS NOT ADEQUATELY SUPPORTED ITS CAPITAL FORECAST

Q. WHY DOES THE PLANNING BASIS FOR THE COMPANY'S CAPITAL FORECAST BEAR ON WHETHER THE COMPANY HAS CARRIED ITS BURDEN?

A. Because the Company's capital forecast would set its capital recovery for the entire plan term, the Company must show that its forecast accurately reflects necessary grid investments over this time period. The IDSP is the proposed process the Authority designed to establish that need before a rate case, through a documented grid needs assessment, scenario-based load forecasting, evaluation of non-wires alternatives, and stakeholder review.[111] The Company's Targeted System Performance Plan, as I explain below, does not provide enough information for a reasonable assessment of those needs on the merits. Without a plan that has been tested in that way, the Company has not substantiated the capital forecast on which its plan depends. For this reason, I recommend in Section IX that the Authority direct Eversource to refile its Targeted System Performance Plan so that it conforms to the IDSP requirements in RE03 PFD No. 2, and that capital funding beyond the first rate year be based on the refiled plan once it has been reviewed.

[111] RE03 PFD No. 2, at pages 8-9, 17-24, 30.

Q. WHAT PLANNING DOCUMENT DID EVERSOURCE FILE TO SUPPORT ITS CAPITAL FORECAST?

A. The Company filed a "Five-Year Targeted System Performance Plan" ("TSP").[112] That plan is the Company's own capital planning document, created without any stakeholder feedback or external evaluation of assumptions, inputs, or modeling during development.

Q. EXPLAIN WHY THE COMPANY'S TSP IS NOT AN ADEQUATE BASIS FOR ITS CAPITAL FORECAST.

A. The Targeted System Performance Plan covers some of the same subject matter as an IDSP, such as an overview of the state of the system and an investment plan. However, it does not follow the structure, process, or planning horizon the Authority has developed throughout the RE03 proceeding. These elements are not superfluous; they are critical to the demonstration that a grid need is real and requires a solution. The Company described its plan as aligning "generally" with the IDSP content "while also reflecting practical differences."[113]

If the RE03 PFD No. 2 is finalized, each EDC's IDSP would have to include, at a minimum, ten defined sections, each with detailed content requirements the PFD specifies.[114] The TSP does not map into that structure. Instead, it is organized by

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112 Docket No. 26-05-10, July 14, 2026 Exhibits CLP-TSP-1 through CLP-TSP-5

113 OCC-566, at page 2.

114 The ten sections are: (1) Executive Summary; (2) Planning Policy; (3) Current State of the System; (4) IDSP Methodology; (5) Stakeholder Engagement and Social Equity; (6) Load Forecasting; (7) Grid Needs Assessment; (8) Solution Selection Process; (9) Capital Investment Plan, covering a ten-year planning horizon; and (10) Long-Term Strategic Plan, covering the period beyond ten years (RE03 PFD No. 2, at page 9 & App. A).

investment category: substations, lines, new customer, asset health, capacity, grid modernization, vegetation management, resiliency, and so on. When asked to identify where the TSP addresses each IDSP section, the Company pointed to scattered pages across several exhibits.[115] For several sections, those references fall well short of what the IDSP would require:

- **Stakeholder Engagement and Social Equity**. An IDSP would have to explain how stakeholders participate in the planning process and how equity considerations are addressed. The Company points to no part of the TSP for this section. It cites two pages of its leadership panel testimony that discuss wholesale supply costs and public benefits charges, not stakeholder participation in grid planning.
- **Solution Selection Process**. An IDSP would have to set out the criteria and methods used to identify, compare, and select both traditional and non-wires solutions. The Company points to three pages of the TSP.
- **Planning Policy and Long-Term Strategic Plan**. An IDSP would have to address the state and local policies that inform grid planning, and separately describe the Company's strategic plans beyond a ten-year horizon. The Company cites the same two pages for both.

Notably, the TSP reflects no stakeholder review of any kind. It does not describe any stakeholder process for evaluating load forecasting or long-term planning, or

[115] OCC-566, at pages 2-3.

any public engagement. Although no stakeholder process was required for the TSP, the absence of one matters. A plan that has not been tested by anyone outside the Company rests entirely on the Company's own assumptions about load growth, grid needs, and solutions, and those are the assumptions that would set its capital recovery. Other states have recognized this and require stakeholder engagement before a utility files its grid plan. Illinois requires utilities to develop their multi-year integrated grid plans through at least six stakeholder workshops over a minimum of five months, run by an independent facilitator, before filing.[116] Maine requires technical conferences or stakeholder workshops before filing to identify the priorities, assumptions, goals, methods, and tools for the utility's grid plan.[117] The TSP covers five years.[118] The Company already prepares ten-year substation plans under N-1 contingency scenarios[119], so the shorter horizon reflects a choice rather than a limitation. RE03 PFD No. 2 would require a ten-year Capital Investment Plan and a Long-Term Strategic Plan looking 10 to 25 years ahead.[120] A longer horizon matters because the equipment the Company installs may remain in service for 40 years or more. A five-year view cannot show whether an

116 220 Ill. Comp. Stat. 5/16-105.17(d)(6), (e) (requiring that integrated grid planning "ensure opportunities for robust public participation through open, transparent planning processes," and establishing a stakeholder workshop process of at least six workshops over a minimum of five months, conducted by an independent facilitator selected by the Illinois Commerce Commission, before the utility files its plan).

117 Me. Rev. Stat. tit. 35-A, § 3147(2) ("The commission shall hold technical conferences or stakeholder workshops before the filing to identify priorities, assumptions, goals, methods and tools that will assist the covered utility in developing a grid plan.").

118 Exhibit CLP-TSP-1, at page 13; Application, at pages 5-6.

119 RE03 PFD No. 2, at p. 35.

120 Id, at pages 9, 65-66.

investment made today will still fit the grid's needs as load growth, DER adoption, and electrification evolve. It also limits the Authority's ability to see long-term trends and to consider whether some investments could be deferred or right-sized.

RE03 PFD No. 2 also contemplates that a Comprehensive IDSP would be filed and reviewed in its own docket three to six months before a rate case.[121] That separate review would give stakeholders and the Authority time to examine the plan, ask questions through discovery and technical meetings, and comment, and it would give the Company an opportunity to revise the plan before it is used to support a rate request.[122] The TSP was filed as a rate case exhibit, with no prior review.

The Company's load forecasting falls short in several respects. RE03 PFD No. 2 directs the EDCs to develop at least three forecasts (low, middle, and high), with the middle forecast serving as the baseline for identifying grid needs; to forecast at the system, planning region, substation, and distribution feeder levels; and to use leading indicators for DER and electrification adoption in the baseline and high scenarios.[123]

The Company forecasts load only at the substation level, and only for each substation's annual peak hour. It develops a 24-hour load profile only after that peak-hour forecast identifies a capacity need.[124] That approach limits what the forecast can reveal in three ways. First, it can miss grid needs that occur outside the

121 Id, at pages 73-74.
122 Id., at page 73.
123 RE03 PFD No. 2, at pages 30, 34.
124 OCC-574.

peak hour. As rooftop solar grows, some constraints arise during low-load, high-generation periods, which is why RE03 PFD No. 2 would require forecasts for winter peak, summer peak, and low-load/high-generation conditions. [125] Second, it cannot identify constraints on individual feeders, where many DER interconnection and hosting capacity limits occur. RE03 PFD No. 2 would require forecasts at the feeder level as well as the substation level.[126] Third, a single peak-hour value does not show how long a constraint lasts or how often it recurs. That information determines whether a non-wires solution such as battery storage or demand response could meet the need. Without it, non-wires options are harder to identify and evaluate, and a traditional wires investment becomes the default.

The Company proposes two forecast scenarios, a 50/50 and a 90/10 peak forecast. They differ only in their weather assumptions, and the Company uses only the 90/10 forecast for system planning.[127] While a 90/10 weather assumption is a common utility practice for reliability planning, the concern is that weather is the only variable the Company's forecast considers. RE03 PFD No. 2 would require low, middle, and high scenarios that reflect different assumptions about load growth, DER adoption, and electrification. Though the middle scenario would serve as the baseline for identifying grid needs, the others, critically, would inform solution design.[128]

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125 RE03 PFD No. 2, at page 30.
126 Id., at pages 30, 34.
127 OCC-574.
128 RE03 PFD No. 2, at page 30.

Scenario-based planning lets a utility and its regulator test whether an investment still makes sense under a range of plausible futures. The Company's capital forecast instead rests on a single view of load growth. That matters here because, under the F-Factor, the capital forecast becomes the cap on capital recovery. If the forecast is too high, the Company would have an approved basis for spending up to it, and customers would bear the cost.

Under the IDSP framework, the load forecast drives the grid needs assessment, which drives solution selection and, ultimately, the capital investment plan. The Company's capital forecast rests on a load forecast built on a single view of load growth, at only substation level, without any scenario analysis and stakeholder review the IDSP would require. It is not a reliable foundation for a capital budget that would set the Company's capital recovery for four years.

VI. EVERSOURCE HAS NOT SHOWN THAT ITS PROPOSED PIMS WILL IMPROVE PERFORMANCE.[129]

Q. WHAT PIM STRUCTURE IS EVERSOURCE PROPOSING IN ITS RATE CASE APPLICATION?

A. Eversource proposes PIMs and reported metrics in three categories: service quality and reliability, customer satisfaction and engagement, and sustainability and

[129] The RE02 PFD, issued July 14, 2025, proposed a "PBR Performance Mechanism Portfolio" of Reported Metrics, Scorecards, and Performance Incentive Mechanisms ("PIMs"), organized by the nine priority outcomes from the Phase I Decision. Among the proposed mechanisms were a System Reliability PIM, a Customer Reliability PIM, the NWS Shared Savings Mechanism, and a Level 1 DER Interconnection PIM (RE02 2025 PFD, Table 1, at pages 7-8).

financial efficiency.[130] Its reliability PIMs follow the general structure of the RE02 designs: a downside-only System Reliability PIM based on Blue Sky SAIDI and SAIFI, with penalties beginning at one standard deviation above a fixed five-year average, and an upside-only Customer Reliability PIM based on repeat CEMI-5 and CELID-6 customers.[131] The Company assigns each PIM its own maximum penalty or incentive: $3.5 million each for the SAIDI and SAIFI penalties, a $3.0 million Customer Reliability incentive, and a "Customer Suite" with a $3.0 million maximum penalty and a $2.0 million maximum incentive.[132] In total, penalties are capped at about $10 million per year and incentives at about $5 million, amounts the Company derives from 0.5 percent of distribution revenues.[133]

The Company's design departs from RE02 in ways that weaken the PIMs' ability to provide the data and performance measures PURA needs to assess the Company's performance and hold it accountable. First, it uses a 2022–2026 baseline, which includes a year that has not yet concluded.[134] That would let the Company's own current-year performance help set the benchmark it will be measured against. The Company also testifies that its SAIDI has been increasing in recent years, indicating longer outages.[135] A baseline built on those recent years would treat worsening reliability as the norm, making a penalty less likely.

130 Exhibit CLP-PBR-1, at pages 66-67.
131 Exhibit CLP-ELP-3, at pages 1-2.
132 Id., at page 2.
133 Id.; Exhibit CLP-PBR-1, at page 66.
134 Exhibit CLP-ELP-3, at pages 1-2.
135 Exhibit CLP-ELP-1, at page 48.

Second, the Company's penalties rise on a sliding scale that begins at one standard deviation and reaches its maximum only at two standard deviations.[136] Under that structure, reliability could deteriorate well past normal year-to-year variation while the Company faces only a fraction of the maximum penalty.

Third, it measures Customer Reliability with a single count of repeat customers, rather than the four sub-metrics RE02 specifies. Those sub-metrics include the percentage of repeat customers, which accounts for changes in the total number of affected customers.[137]

Fourth, it folds the Level 1 DER Interconnection PIM into a composite "Customer Suite" with four unrelated customer-service measures, such as digital engagement and call handling time, and sets a Company-selected target of 35 business days.[138] RE02 proposes a standalone PIM benchmarked to a three-year historical average.[139] In a composite, slow interconnection processing could be offset by strong performance on unrelated measures, so the Company would face no consequence for the delays that matter most to customers seeking to interconnect.

Fifth, it omits the NWS Shared Savings Mechanism entirely.[140] That mechanism is the one PIM designed to reward the Company for choosing lower-cost non-wires solutions over capital investment. Omitting it removes the only counterweight to the capital bias the rest of the proposal reinforces.

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136 Exhibit CLP-ELP-3, at pages 1-2.
137 RE02 PFD No. 2, at page 46.
138 Exhibit CLP-ELP-3, at pages 1-2.
139 RE02 PFD No. 2, at pages 76-79.
140 See id., at page 23.

Q. WHAT ARE THE SPECIFIC DESIGN ELEMENTS OF THE SYSTEM RELIABILITY PIM AND THE CUSTOMER RELIABILITY PIM PROPOSED BY PURA?

A. The proposed System Reliability PIM is downside-only.[141] It measures Blue-Sky SAIDI and Blue-Sky SAIFI as two separate sub-metrics to be evaluated annually against a fixed five-year historical average calculated under IEEE (Institute of Electrical and Electronics Engineers) methodology and excluding major event days, using transmission and distribution reliability performance filing data. The penalty applies only when annual performance exceeds one standard deviation above (i.e. directionally worse) that fixed five-year average, with the dollar penalty amount to be set in each utility's rate case.[142]

The Customer Reliability PIM is upside-only.[143] It tracks four sub-metrics averaged into a single composite score: CEMI-5, percent of repeat CEMI-5 customers, CELID-6, and percent of repeat CELID-6 customers.[144] The financial incentive becomes available only if that composite score falls below (i.e. directionally better) a threshold equal to the fixed 2020–2024 historical average composite value plus

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141 A downside-only PIM carries a financial penalty if the Company's performance falls below the target, but no financial reward if performance exceeds it.

142 RE02 2025 PFD, at pages 32-35.

143 An upside-only PIM provides a financial reward if the Company's performance exceeds the target, but no penalty if performance falls short.

144 "CEMI-5" (Customers Experiencing Multiple Interruptions) counts customers who experienced five or more sustained interruptions in a year. "CELID-6" (Customers Experiencing Long Interruption Durations) counts customers who experienced an interruption lasting six hours or more. The "percent of repeat" sub-metrics measure the share of customers on each year's CEMI-5 or CELID-6 list who also appeared on the prior year's list, to identify customers with chronic reliability problems. (RE02 PFD (July 14, 2025), at pages 35-39; see also Exhibit CLP-ELP-3, at page 1).

one standard deviation. The reward is a capped, fixed dollar amount, with the maximum amount set in each utility's rate case.[145]

I recommend that the Authority (1) adopt these two PIMs, and (2) not attach a financial reward to the Customer Reliability metric. Reliable service is a core obligation of the Company. The Company should face penalties for underperforming on reliability, but it should not be rewarded for improving it. If the Authority nonetheless makes a reward available, it should not use the threshold the Company proposed. Read literally, that threshold would pay a reward for performance up to one standard deviation worse than the 5-year historical average, which does not advance the Reliable and Resilient Electric Service or Affordable Service priority outcomes. The reward threshold should instead be set at the historical average minus one standard deviation, so that the Company is rewarded only for improvement beyond normal year-to-year variation.

Q. ARE THE COMPANY'S PROPOSED PIMS SUFFICIENT TO HOLD IT ACCOUNTABLE FOR PERFORMANCE?

A. No, for two reasons. First, the amounts at stake are very small relative to the rest of the plan. The Company's maximum annual penalty across all PIMs is about $10 million, or about $40 million over a four-year plan term.[146] By comparison, the Company estimates that the return it seeks to collect through the F-Factor would add $124.1 million over the same term, roughly three times its maximum

[145] RE02 2025 PFD, at pages 35-39.
[146] Exhibit CLP-ELP-3, at page 2.

penalty exposure.[147] Second, the Company would make its PIMs available only if the Authority approves its plan.[148] The RE01 Proposed Final Decision takes the opposite approach, which I support as a more reasonable option: performance mechanisms and the IDSP apply whether or not a utility accepts a multi-year rate plan, and declining an MRP "does not exempt the EDC from the requirements of Performance Mechanisms and the IDSP."[149] Accountability for performance should not be something the Company offers in exchange for approval of its preferred revenue mechanisms.

Q. SHOULD PIM REWARDS BE AVAILABLE IN ADDITION TO THE COMPANY'S AUTHORIZED RETURN ON EQUITY?

A. The RE01 Proposed Final Decision treats PIM incentives and penalties separately from the authorized ROE, while directing the Authority to "consider the presence of PBR mechanisms when evaluating the utility-specific risk factors."[150] I recommend that the Authority take this approach. PIM rewards give the utility an additional opportunity to earn money, and that opportunity is part of the utility's overall balance of risk and return. The Company requests an ROE of 10.25 percent and proposes up to about $5 million per year in PIM incentives.[151] In setting the Company's ROE, the Authority should consider the holistic PIM portfolio it ultimately adopts, including both penalty exposure and any reward opportunity.

147 OCC-423, at page 7.
148 Exhibit CLP-ELP-1, at page 50.
149 RE01 PFD, at page 10.
150 Id. at page 42.
151 Application, at page 3; CLP-ELP-3, at page 2.

Where PIMs offer rewards, the total return available to the Company, including those rewards, should be no greater than the Authority would otherwise find just and reasonable.

Q. HOW DO YOU RECOMMEND THE COMPANY'S PROPOSED PIMS BE IMPROVED?

A. The Authority should decline to adopt Eversource's Company-designed PIMs portfolio. PURA should instead adopt the PIM designs set out in the RE02 PFD No. 2, including the downside only System Reliability PIM, the Level 1 DER Interconnection PIM, the NWS Shared Savings Mechanism, and the other PIMs identified in that decision, together with their incentive structures and per-PIM exposure caps, and make them effective whether or not the Authority approves a multi-year rate plan. For the reasons I note above, the Customer Reliability metric should be adopted as a Scorecard, without a financial reward.

Adopting PIMs in this proceeding, using the RE02 designs, allows the Authority to begin measuring Eversource's performance when new rates take effect, whatever it decides about the Company's proposed revenue mechanisms. The RE02 record supports adopting the PIMs developed in that proceeding here. The System Reliability PIM and Customer Reliability PIM methodologies have been proposed twice, a year apart, without substantive changes, and the Authority stated that "[n]o further modifications are warranted" to the System Reliability PIM's design.[152]

[152] RE02 PFD No. 2, at page 41.

Because RE02 leaves the dollar amount of each PIM to the rate case, I recommend that the Authority set System Reliability PIM penalty amounts in this proceeding at levels no lower than the maximum SAID and SAIFI penalties the Company itself proposes in Exhibit CLP-ELP-3, applied to the RE02 proposed design. These penalty amounts should not, however, be considered as ceilings, as a PIM should be designed with some amount of stretch to provide actual incentive to improve. Rather, they should be considered a floor because the Company itself, in proposing them, establishes these amounts as workable and reasonable. No reward should attach to reliability performance. Providing safe and reliable service is a core obligation the Company already undertakes in exchange for its authorized return, and customers should not pay extra for it. Reliability should instead be enforced through penalties for underperformance.

VII. TAKEN TOGETHER, EVERSOURCE'S PBR PROPOSAL WOULD SHIFT RISK TO CUSTOMERS AND WOULD NOT CONTAIN COSTS.

Q. WHAT IS THE CUMULATIVE EFFECT OF THE PBR MECHANISMS THE COMPANY PROPOSES?

A. Each of the Company's departures from the RE01, RE02 and RE03 design shifts risk from the Company to its customers, and the departures reinforce one another. The capital funding mechanism funds capital at the Company's own forecast as plant enters service, so customers bear the risks that the forecast is too high or that the Company's investment choices are imprudent until a later reconciliation. The revenue cap has two weaknesses. First, it applies only to OM&A, so it places no

discipline on capital, the category of costs on which the Company earns a return. Any dollar the Company shifts from an operating solution to a capital solution leaves the formula entirely. Capital spending is limited instead by the Company's own forecast, which the Company has a financial incentive to set high. Second, even for OM&A, the formula provides little discipline. The Company's proposed X-Factor is negative (−0.03 percent), so on its own it would let OM&A revenues grow slightly faster than inflation. Only the Company's proposed 0.30 percent Consumer Dividend produces any net offset to inflation, and that offset is about 0.27 percent per year.[153]

The Company's proposed PIMs would put only about $10 million per year at risk, and the Company offers them only if the Authority approves its PBMRP. And the capital forecast that drives the rest of the plan rests on the Company's Targeted System Performance Plan. That plan does not map onto the thoroughly scrutinized IDSP framework and was developed without any stakeholder review, so it gives the Authority no independently vetted basis for testing the forecast.

The Company acknowledges that it introduced new elements to its PBR proposal "to remediate the flaws that would ultimately hinder PURA's (draft) PBR model from supporting the necessary stay-out terms". It calls the CT-Bar's exclusion of the cost of capital "a non-starter".[154] The Company's proposal reflects what *the Company wants* from a multi-year rate plan, not the cost containment and

153 Exhibit CLP-PBR-1, at pages 42, 64.
154 OCC-423, at pages 2-3).

accountability that customers are supposed to receive in exchange for accepting one. Those protections are identified in the Phase 1 Decision as core objectives of PBR in Connecticut. They include the priority outcomes of Business Operations and Investment Efficiency and Affordable Service, and the foundational consideration of Risk Distribution. They are also consistent with the Take Back Our Grid Act's direction that the PBR framework measure utility performance on objectives such as cost efficiency and affordability.[155]

Q. WHAT DO CUSTOMERS RECEIVE IN EXCHANGE FOR THE RISK THE PROPOSAL ASKS THEM TO BEAR?

A. Customers do not receive sufficient benefit to categorize the Company's proposal as reasonable. In a well-designed multi-year rate plan, customers accept several years of formula-based rate increases in exchange for stronger incentives for cost control, protection from imprudent spending, and meaningful accountability for performance. The Company's proposal asks customers to accept annual rate increases without providing corresponding guardrails. The Company requests a 10.25 percent return on equity, would authorize capital recovery up to roughly 40 percent above its recent historical average, and could earn PIM rewards on top of its authorized return. It has not shown that customers would be better off under its plan than under either the framework the Authority developed in the reopeners or conventional cost-of-service ratemaking. In my opinion, customers would likely be

[155] Phase 1 Decision, at pages 14-16; Conn. Gen. Stat. § 16-244aa(b)(1).

worse off. By the Company's own estimate, collecting a return on new capital before prudence is established would cost customers $124.1 million more over the plan term than the CT-Bar. That figure does not include the effects of funding capital up to a forecast that has not been independently reviewed, or of a revenue cap formula that applies little productivity discipline. Without that showing, the Company has not carried its burden, and the plan should not be approved.

The Company's proposed Consumer Dividend does not change this conclusion. Its consultant's benchmarking shows the Company's OM&A costs averaging 11.9 percent above the model-predicted benchmark from 2015 through 2024, and 31.5 percent above it in 2024.[156] From 2021 through 2024, the Company's OM&A costs were 16.4 percent above the benchmark, and over the full 2015-2024 period it ranked 54th of 88 utilities in the study.[157] Given the magnitude of risk the Company is attempting to shift onto ratepayers, its proposed consumer dividend is far too small to meaningfully address that shifted risk.

The Company agrees that a utility whose OM&A costs are materially above benchmark "would generally warrant a higher Consumer Dividend."[158] Yet it proposes a Consumer Dividend of 0.30 percent, in the lower half of the 0.15 to 0.60 percent range its consultant identifies.[159] The Company acknowledges that it did not derive its proposed 0.30 percent Consumer Dividend from its own consultant's

156 Exhibit CLP-PBR-1, at page 56.
157 OCC-559, at pages 3-4.
158 OCC-539(a), at page 1.
159 Exhibit CLP-PBR-1, at page 58-59; Exhibit CLP-PBR-3, Figure 16.

benchmarking results.[160] Nor does the dividend respond to that benchmarking: it rises above its 0.30 percent floor only if the Company outperforms an inflation-adjusted benchmark of its own controllable O&M costs per customer, so it does not increase because the Company's costs are above its peers'.[161] The tiered approach described in the RE01 PFD, by contrast, would assign a larger stretch factor to utilities shown to be less efficient than their peers.[162] Net of the Company's negative X-Factor, the dividend reduces OM&A revenue growth by only about 0.27 percent per year below inflation, and it does nothing to offset the $124.1 million return the Company would collect on new capital before prudence is established.[163]

VIII. EVERSOURCE'S JUSTIFICATIONS DO NOT CARRY ITS BURDEN, AND APPROVING ITS PROPOSAL WOULD HARM THE PUBLIC INTEREST BEYOND THIS CASE.

A. The Company Has Not Shown That Its Proposal Serves Customers or the Priority Outcomes

Q. IS YOUR POSITION THAT EVERSOURCE SHOULD NOT BE PERMITTED TO PROPOSE ANY REFINEMENTS TO THE RE01, RE02, OR RE03 RECORD IN ITS RATE CASE?

A. No. I do not oppose refinements to an evolving framework. Where the Authority has already developed specific mechanics through the RE01, RE02, and RE03

160 OCC-559 (c), at page 3; OCC-559, at page 4 (reproducing OCC-443).
161 Exhibit CLP-PBR-1, at page 64; CLF-AC-005, at page 1, OCC-539(b), at page 2.
162 RE01 PFD, at pages 22-23 & App. A n.50.
163 Exhibit CLP-PBR-1, at pages 42, 64; OCC-435, at page 1, Table 1.

process, a rate case proposal that builds on those mechanics, or proposes a targeted, justified modification to them, may be reasonable. What is *not* reasonable is a proposal that replaces those mechanics outright with a company-preferred alternative, without showing that the alternative better serves customers. Eversource has done that with respect to the revenue adjustment mechanism, the capital funding mechanism, and the PIMs portfolio. Its Targeted System Performance Plan also falls well short of the IDSP framework developed in the RE03 PFD No. 2. Nothing prevented the Company from proposing its own design in this rate case. But that design must stand on its own merits, and it does not. As I explain in Sections IV through VII, it would not produce just and reasonable rates or advance the priority outcomes adopted in the Phase 1 Decision, and the Company has not shown otherwise. The Authority should not adopt it.

Q. HAS EVERSOURCE SHOWN THAT ITS ALTERNATIVE MECHANISMS IMPROVE ON THE REOPENER FRAMEWORKS?

A. No. A different mechanism is an improvement only if it better serves the goals and priority outcomes the Authority adopted in the Phase 1 Decision, which govern all of the reopeners. The Company has not shown that its mechanisms do so. Its proposal would benefit the Company while weakening the priority outcomes it most directly affects:

- **Business Operations and Investment Efficiency**: it removes capital from the revenue cap formula and pays a return on new capital before prudence is shown.

- **Affordable Service**: by the Company's own estimate, the F-Factor would add $124.1 million in capital costs over the plan term compared with the CT-Bar.[164]
- **Comprehensive and Transparent System Planning**: it replaces the proposed IDSP with a capital plan the Company prepared on its own without any stakeholder involvement.
- **Risk Distribution**: it shifts the risk of imprudent capital spending from shareholders onto customers.

B. Approving Company's Proposal Would Create Risks for Future Rate Cases and Weaken the Statewide PBR Framework

Q. HOW WOULD APPROVING THE COMPANY'S PROPOSAL IN THIS RATE CASE CREATE RISKS BEYOND THIS CASE?

A. The Take Back Our Grid Act directed the Authority to "initiate a proceeding to investigate, develop and adopt a framework for implementing performance-based regulation of each electric distribution company." From a regulatory policy perspective, a framework developed in one proceeding and then applied to each company promotes consistency and gives all stakeholders the same opportunity to shape it. Eversource's rate case does not implement any Authority-led framework; it proposes the Company's preferred framework. Adopting company-designed, first-generation PBR mechanisms in a rate case before the statewide framework is

[164] OCC-423, at page 7.

final would let one company's litigation position shape questions that affect both distribution companies (Public Act 20-5, §§ 1(b), 3(b)).

Q. DO YOU AGREE WITH EVERSOURCE THAT A SPECIFIC PBR PLAN CAN ONLY BE ADJUDICATED IN A RATE CASE?[165]

A. No. Eversource conflates two distinct questions: (1) what the PBR framework should be, and (2) how that framework should be applied to a specific utility's specific revenue requirement. The second question appropriately belongs in a rate case. An EDC's actual PBMRP, tailored to its own capital plan, cost structure, and circumstances, must be adjudicated with company-specific evidence. The first question, the design of a Revenue Cap Formula, the structure and guardrails of a capital funding mechanism, and the composition and asymmetry of a PIMs portfolio, benefits from a record built through years of multi-stakeholder participation that a single rate case cannot replicate. That is the record developed in Docket No. 21-05-15 and its reopeners. This is also why my primary recommendation does not ask the Authority to design a new framework in this case. Instead, I recommend that the Authority apply the design developed on the reopener record to Eversource's company-specific facts, which is the question that appropriately belongs in a rate case. Whatever the Authority decides here, it should

[165] Eversource claims that implementing a performance-based ratemaking framework "is a critical issue that can occur only in the context of a rate proceeding," and that because the PBR reopener dockets were uncontested, PURA "was only ever going to be able to implement PBR in a contested rate proceeding" (Docket No. 26-05-10, September 9, 2026 Eversource Response to Motion No. 43, at pages 1-2). Eversource also acknowledges, however, that PURA's decisions in those dockets "would inform the docket in future rate proceedings," and that "sufficient work was done in those dockets to inform this proceeding from a policy perspective" (id., at pages 2-3).

state explicitly that its decision does not set precedent for the design of multi-year rate plans for Eversource or any other Connecticut electric distribution company.

Q. WHAT ARE THE TIMING CONSEQUENCES OF APPROVING A COMPANY-DESIGNED PBMRP BEFORE THE STATEWIDE FRAMEWORK IS FINAL?

A. They are significant. If the Authority approves a PBMRP for Eversource in this docket, the Company's mechanisms would presumably govern its rates for the full plan term. Incorporating the eventual outcomes of RE01, RE02, and RE03 into that already-approved plan would likely require a multi-year lag and a subsequent proceeding to true it up.

Q. WHY SHOULD THE AUTHORITY CONSIDER THE RECORD DEVELOPED IN THE PBR REOPENER DOCKETS WHEN EVALUATING THE COMPANY'S PROPOSAL?

A. Many of the organizations that invested years of staff time in Docket No. 21-05-15 and the RE01, RE02, and RE03 reopeners are Connecticut-based nonprofits, frontline and consumer advocacy organizations, and other parties with limited resources. Their staff live and work in the communities Eversource serves, the same communities that experience the outages, the bill impacts, and the affordability pressures these dockets ultimately seek to address. Their recommendations in the reopeners were informed by direct, on-the-ground experience with how the Company's rates and performance affect Connecticut customers.

Those organizations were able to participate meaningfully in the reopeners because they were uncontested proceedings designed for multi-stakeholder engagement over an extended timeline, with technical meetings, straw proposals, and repeated opportunities for written comment. A base distribution rate case is different. Meaningful participation in a contested proceeding requires legal representation, expert witnesses, discovery, and a compressed, resource-intensive litigation schedule that many of those same organizations cannot support.

If the Authority decides first-generation PBR mechanics in this rate case without reference to the reopener record, its decision would rest on a much narrower set of perspectives. It would also allow a single company's filing, made before the reopeners are finalized, to supersede years of stakeholder engagement. This outcome would undermine the substantial resources that docket participants invested in the PBR proceedings and discourage participation in the Authority's future stakeholder processes.

IX. <u>IX. RECOMMENDATIONS.</u>

C. The Authority should reject Eversource's Proposed PBMRP

Q. WHAT IS YOUR PRINCIPAL RECOMMENDATION?

A. The Authority should reject the Company's proposed PBMRP, including its revenue adjustment mechanism, capital funding mechanism, and PIMs portfolio. The Company bears the burden of demonstrating that its proposal will produce just and reasonable rates, serve the public interest, and advance the priority outcomes adopted in the Phase 1 Decision. For the reasons set out in Sections IV through

VIII, it has not done so. Because the plan's flaws are structural, they cannot be cured by adjusting individual parameters. In its place, the Authority should apply the PBR framework developed in Docket No. 21-05-15 and its reopeners, as reflected in the RE01, RE02, and RE03 Proposed Final Decisions, to the extent it adopts PBR mechanisms for Eversource in this proceeding. Under that approach, the Authority should set going-in rates for the first rate year and direct Eversource to refile its Targeted System Performance Plan so that it conforms to the IDSP requirements in RE03 PFD No. 2, with the reviewed plan providing the basis for capital funding in the remaining years. If the Authority declines to do so, it should set the Company's base distribution rates through traditional cost-of-service ratemaking. In either case, it should adopt the RE02 performance mechanisms, with the few modifications I describe below, and require Eversource to file a Comprehensive IDSP in accordance with the final decision in Docket No. 21-05-15RE03.

D. Primary Recommendation: Apply the Framework Developed in Docket No. 21-05-15 and Its Reopeners

Q. WHAT DO YOU RECOMMEND THE AUTHORITY ADOPT IN PLACE OF THE COMPANY'S PROPOSAL?

A. To the extent the Authority adopts PBR mechanisms for Eversource in this proceeding, I recommend that it adopt the elements described below, which are drawn from the RE01, RE02, and RE03 Proposed Final Decisions. The Authority should also state explicitly that its decision does not set precedent for the design

of multi-year rate plans, and that the statewide framework that emerges from the reopeners will govern future plans for Eversource and the other electric distribution company.

I recognize that the Company has said it could not commit to a stay-out if the capital funding mechanism excludes the cost of capital, as the CT-Bar does.[166] The RE01 Proposed Final Decision anticipates that possibility. If a utility declines the stay-out, the multi-year plan does not take effect, the Revenue Cap Formula and CT-Bar are not available, and rates are set for the first rate year only, while the performance mechanisms and IDSP requirements continue to apply.[167] That outcome would be consistent with the framework and with my alternative recommendation below.

Q. WHY SHOULD THE AUTHORITY ADOPT THE PBR ELEMENTS DRAWN FROM THE RE01, RE02, AND RE03 PROPOSED FINAL DECISIONS?

A. Because those elements are the product of years of deliberate, collaborative work. The PBR elements in the three reopener proposed final decisions were developed through an open process in which every stakeholder, including Eversource, had repeated opportunities to shape the outcome. The Authority described the RE03 PFD No. 2 result as reflecting "the culmination of extensive stakeholder engagement, iterative refinements, and Authority analysis."[168] The record is also

166 OCC-423, at pages 3, 8.
167 RE01 PFD, at page 10.
168 RE03 PFD No. 2, at page 1.

balanced. The Authority stated that its purpose was "to document the substantial stakeholder input" and to explain why it chose each mechanism it adopted.[169] The proposed final decisions do exactly that. For each mechanism, the Authority summarizes the straw proposal, sets out the positions of the participants, and then explains its own analysis and conclusion.[170] The outcome is a framework that reflects ratepayer, environmental, industrial, labor, and utility perspectives, weighed against one another in the open.

The reopeners were designed to work together and to serve the objectives the Authority established in Phase 1. The Authority has explained that planning, revenue adjustment mechanisms, and performance evaluation are "mutually constitutive of each other" and function "as an iterative whole" (RE03 PFD No. 2, at page 7).[171] Each reopener was built expressly to advance the four regulatory goals, five foundational considerations, and nine priority outcomes adopted in the Phase 1 Decision.[172]

Q. WHAT REVENUE ADJUSTMENT MECHANISMS DO YOU RECOMMEND THAT PURA ADOPT?

A. I recommend that the Authority adopt the revenue adjustment mechanisms proposed in the RE01 PFD, for the reasons explained above. I emphasize one element of that design that the Company's proposal omits, and I recommend two

169 RE01 PFD, at page 1.
170 Id., at pages 7-8.
171 RE03 PFD No. 2, at page 7.
172 RE01 PFD, at page 5; RE02 PFD No. 2, at page 1; RE03 PFD No. 2, at page 1.

changes to the RE01 PFD design. My full recommendations are set out in Appendix C and reflect the RE01 PFD design, with the inclusion of the changes described here.

First, the revenue cap formula should apply to the Company's total revenue requirement, covering both capital and OM&A costs, as the RE01 PFD proposes.[173] A revenue cap that covers only part of the revenue requirement cannot contain costs because costs simply shift to the part the cap does not reach.

Second, the X-Factor should be based on a total factor productivity study that meets the RE01 PFD's proposed requirements, including the use of customer count, delivered energy, and peak demand as outputs.[174] As a change to the RE01 PFD, which allows the X-Factor to be positive or negative, I recommend the Authority not approve a negative X-Factor based on a study that does not meet those requirements.[175]

Third, while the RE01 PFD would fund Capital Plan additions through the CT-Bar beginning in Rate Year 1[176], I recommend the CT-Bar not fund capital additions, including the Rate Year 1 CT-Bar additions the RE01 PFD would include in going-in rates, until the Company has refiled its Targeted System Performance Plan in a form that conforms to the IDSP requirements proposed in RE03 PFD No. 2 and the Authority has reviewed it. Once the reviewed plan is in place, it should provide the

173 RE01 PFD, at pages 20–21 & n.19.
174 Id., at pages 22-25.
175 RE01 PFD, at page 22.
176 RE01 PFD, at pages 33, 37 (Calculation Methodology, Step 2) & 40 (Guideline 9).

capital input to the CT-Bar for the remaining years of the plan. The RE01 PFD assumes that the Capital Plan is supported by a reviewed IDSP. Here, no such plan exists.

Q. WHAT PERFORMANCE MECHANISMS DO YOU RECOMMEND THE AUTHORITY ADOPT?

A. I recommend that the Authority adopt the performance mechanisms proposed in RE02 PFD No. 2, which are set out in Appendix C, and make them effective whether or not a multi-year rate plan is approved. I recommend the following changes to the RE02 PFD No. 2 proposed design:

1. A Customer Reliability Scorecard, rather than an upside-only PIM with no financial reward, that tracks Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Duration (CELID), focused specifically on repeat appearances by the same customers year over year to identify chronically underserved customers, with the option to elevate it to a downside-only PIM once sufficient data are available.[177] Reliable service is a core obligation the Company already undertakes in exchange for its authorized return.
2. A Time-Varying Rate Scorecard, or a Reported Metric that converts to a Scorecard, with enrollment targets as AMI deployment is completed, reported separately for LMI and non-LMI customers that tracks customer

[177] The RE02 PFD No. 2 proposes to adopt Customer Reliability as an upside-only PIM that rewards the Company when its composite score falls below the five-year historical average plus one standard deviation (RE02 PFD No. 2, at pages 44-46).

enrollment/participation in time-varying (time-of-use) rate options.[178] Without targets, there is no benchmark for judging whether the Company is enrolling customers in time-varying rates. And without separate LMI reporting, the Authority cannot tell whether the bill savings that time-of-use rates can offer are reaching the customers who need them most.

3. Community Engagement Scorecard, rather than a Reported Metric, built on the three consolidated sub-metrics in RE02 PFD No. 2 (number of activities, public participation, and actionable outcomes), with targets for outreach activity and an equity sub-metric for Environmental Justice community representation on advisory boards, or at a minimum a Reported Metric with a stated path to a Scorecard.[179] A Reported Metric only records what the Company chooses to do, while targets set an expectation for meaningful engagement with the communities that have historically had the least say in utility decisions.
4. A Level 2 DER Interconnection Scorecard that tracks the average number of business days in Company-controlled processing steps for fast-track Level 2 DER interconnection projects, using the 4-step calculation in RE02 PFD No. 2, benchmarked against the EDC interconnection guidelines and a five-year historical average. If Level 2 processing times lengthen while Level 1 times

[178] The RE02 PFD No. 2 proposes adopting Time-Varying Rates as a Reported Metric with no enrollment targets and only suggests that future versions "may benefit from" separate LMI reporting (RE02 PFD No. 2, at pages 70-71).

[179] The RE02 PFD No. 2 proposes adopting Community Engagement as a Reported Metric only (RE02 PFD No. 2, at pages 74-75).

improve, the Authority should consider elevating the Scorecard to a PIM.[180] A financial incentive tied only to Level 1 projects could lead the Company to prioritize smaller projects over larger ones, which deliver more clean energy capacity, and RE02 PFD No. 2 itself recognizes that the Scorecard data would provide "a basis for adjustments" in that scenario.[181]

Q. WHAT DISTRIBUTION PLANNING ELEMENTS SHOULD PURA ADOPT?

A. I recommend that the Authority adopt the integrated distribution planning requirements proposed in the RE03 PFD No. 2, which are set out in Appendix C, with two additions specific to this case. First, I recommend that the Authority direct Eversource to refile its Targeted System Performance Plan, either as a compliance filing in this docket or in a subsequent docket, as the Authority deems appropriate, so that it conforms to the IDSP requirements set out in RE03 PFD No. 2. Under this approach, the Authority would set going-in rates for the first rate year in this docket without relying on the Company's capital forecast. The Company's proposed going-in revenue requirement already includes forecast capital additions through the rate year, which is why it sets its first-year F-Factor at zero.[182] Consistent with the RE01 Proposed Final Decision, going-in rates should instead reflect plant that is in service, and shown to be prudent and used and useful, as of the close of the

[180] RE02 PFD No. 2 proposes adopting the Level 2 DER Interconnection Scorecard without saying what adjustment would follow if Level 2 performance worsens (RE02 PFD No. 2, at pages 79-80).
[181] RE02 PFD No. 2, at pages 79-81.
[182] CLF-AC-001, at page 8 n.2.

evidentiary record.[183] Once the refiled plan has been reviewed, the capital investments it supports could be reflected in the capital funding component of the revenue cap formula (the CT-Bar) for the remaining years of the plan. The IDSP filing would not require the Authority to redesign the formula or reopen this rate case. It would simply update the capital input to a formula approved in this docket, much as the annual revenue adjustment mechanism updates other inputs each year. Until the refiled plan has been reviewed, the CT-Bar should not fund capital additions by reference to the Company's current forecast. The refiled plan would serve as the interim basis for capital funding until the Company files its first Comprehensive IDSP under the final decision in Docket No. 21-05-15RE03.

Second, building on the Grid Needs Assessment and Hosting Capacity Requirements proposed in the RE03 PFD No. 2 (recommendations #9 and #10 in Appendix C), I recommend that the IDSP consider using N-1 capacity reserve to host distributed energy resources. As proposed in the RE03 PFD No. 2, the Grid Needs Assessment would include an N-1 contingency analysis, which tests whether the distribution system can continue to serve load if a single component, such as a substation transformer, is out of service.[184] To meet that standard, utilities hold capacity in reserve at their substations and on their feeders. That reserve is needed only during a contingency event; in most hours of the year, it is not used.

183 RE01 PFD, at pages 15, 19.
184 RE03 PFD No. 2, at page 41.

Eversource already prepares ten-year substation plans using N-1 contingency analysis, so it has the information needed to identify where that reserve exists.[185] That reserve capacity can be made available to distributed energy resources if those resources are automatically tripped offline, or their output is curtailed, during the rare periods when a contingency occurs. This approach lets DER interconnect using existing infrastructure, rather than waiting for, and paying for, substation upgrades sized as though the DER must be accommodated at all times, including during a contingency.

The New York Public Service Commission recently approved this approach in National Grid's electric rate case. Under the joint proposal the Commission adopted, National Grid must evaluate "automatic tripping and other smart grid solutions for N-1 contingency scenarios" within six months. Where those solutions can lower substation costs related to hosting DER, National Grid must notify eligible customers in its interconnection queue, integrate the solutions into its interconnection studies going forward, and "update its online hosting capacity maps to indicate where such smart grid solutions may be appropriate."[186]

The IDSP framework is well suited to this approach. The N-1 contingency analysis would identify where capacity is held in reserve, and the Hosting Capacity Analysis and hosting capacity maps would show developers and the Authority where that

[185] Id., at page 35.

[186] Case 24-E-0322 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, Order Adopting Terms of Joint Proposal and Establishing Rate Plans (N.Y. Pub. Serv. Comm'n, issued Aug. 14, 2025), at pages 56–57 and 106 (Ordering Clause 1).

capacity could be used. RE03 PFD No. 2 already directs the EDCs to discuss "planned enhancements (like system modifications to increase hosting in high-DER areas)" and to identify solutions for areas with limited hosting capacity in the DER Interconnection Plan.[187] In the RE03 proceeding, OCC likewise urged that "cost-effective use of existing infrastructure and flexible interconnections should be prioritized before proactive investments are made to the grid."[188]

Making better use of existing reserve capacity advances the Distribution System Utilization and Affordable Service priority outcomes. It can reduce interconnection costs for DER developers and reduce the need for new substation capacity whose costs customers would otherwise bear. Therefore, I recommend that the Authority require Eversource to evaluate these solutions as part of its refiled Targeted System Performance Plan and its Comprehensive IDSP, and to reflect the results in its hosting capacity maps.

E. Alternative Recommendation: Set Rates on a Conventional Cost-of-Service Basis Without First-Generation PBR Mechanics

Q. WHAT DO YOU RECOMMEND IF THE AUTHORITY DECLINES TO IMPLEMENT PBR AS OUTLINED IN THE REOPENERS?

A. In that case, the Authority should set Eversource's base distribution rates in this docket on a conventional cost-of-service basis, without incorporating first-generation PBR mechanics, while it finalizes the statewide PBR framework in the

[187] RE03 PFD No. 2, at pages 42-43.
[188] Id. at page 38 (citing OCC May Comments, at page 6).

Docket No. 21-05-15 RE01, RE02, and RE03 reopeners. Under that approach, rates would be based on the Company's test-year costs and a return on prudently incurred investment, as reviewed by the Authority, and the Authority should not adopt the Company's proposed revenue adjustment mechanism or capital funding mechanism. This would be consistent with the one-year rate plan the RE01 Proposed Final Decision contemplates when a multi-year plan does not take effect, which would retain existing revenue adjustments where applicable. The Authority should also explicitly state in its Final Decision that nothing decided in this proceeding prejudges, narrows, or may be cited as precedent for the statewide PBR framework. As I explain below, factual information developed in this case can inform the reopeners, but the Company's proposed mechanisms should carry no presumptive weight there.

I recognize that this approach would delay Eversource's transition to PBR. That cost should be weighed against the cost of approving a plan the Company has not shown to be just and reasonable, whose design would govern its rates for the full plan term. A short delay in implementing a well-designed framework is preferable to locking in a flawed one. The Company states that, without a multi-year plan, it would file rate cases as often as every 18 months, and it projects that this would produce larger, less frequent bill increases than its PBMRP.[189] Smoother increases are a benefit only if the underlying rates are just and reasonable, and each of those

[189] CLF-AC-001, pages 29-30 (EOE-156).

rate cases would include a full review of the Company's costs and the prudence of its investments.

Q. IF THE AUTHORITY DEFERS THE PBR ISSUES RAISED IN THIS PROCEEDING TO THE DOCKET NO. 21-05-15 REOPENERS, MUST THE RECORD DEVELOPED IN THIS RATE CASE BE RE-DEVELOPED FROM SCRATCH?

A. No. This rate case has highlighted substantial, current information relevant to the ongoing RE01, RE02 and RE03 proceedings, including updated capital spending forecasts and trends, updated benchmarking results, and an alternative set of mechanics newly recommended by Eversource. My recommendation is not that this information be discarded, but that it can, as appropriate, be used to inform Docket No. 21-05-15 to support the Authority's deliberations in those proceedings.

F. Recommendations That Apply in Either Case

Q. ARE THERE RECOMMENDATIONS THAT APPLY REGARDLESS OF WHAT APPROACH THE AUTHORITY TAKES?

A. Yes. Consistent with the RE01 Proposed Final Decision, and with RE02 PFD No. 2's direction that potential PIMs be implemented in each company's rate case, the Authority should adopt the RE02 performance mechanisms in this proceeding, with the changes I have outlined above, set a fixed dollar incentive or penalty for each PIM, and make them effective whether or not a multi-year rate plan is approved.[190]

[190] RE01 PFD, at page 10.

In setting the Company's return on equity, the Authority should consider the net risk and earnings opportunity of the adopted PIM portfolio as part of its evaluation of the Company's risk.[191] The Authority should also require Eversource to file a Comprehensive IDSP in accordance with the final decision in Docket No. 21-05-15RE03, on the schedule that decision establishes. RE03 PFD No. 2 proposes that the first Comprehensive IDSP be filed within 18 months of the final decision, or three to six months before the EDC's next rate application, if that comes first.[192] Under my primary recommendation, the refiled Targeted System Performance Plan would serve as the interim basis for capital funding until the Company has filed a Comprehensive IDSP and that plan has completed the review process established in the final decision in Docket No. 21-05-15RE03. Until a capital forecast has been reviewed through a process that conforms to the IDSP requirements, the Authority should not approve any mechanism that sets capital recovery by reference to it.

X. CONCLUSION AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Authority:

(1) reject the Company's proposed PBMRP, including its revenue adjustment mechanism, capital funding mechanism, and PIMs portfolio, because the Company has not demonstrated that the proposal will produce just and reasonable rates, serve

191 Id., at page 42.
192 RE03 PFD No. 2, at pages 73-74.

the public interest, or advance the priority outcomes adopted in the Phase I Decision;

(2) to the extent it adopts PBR mechanisms for Eversource in this proceeding, apply the framework developed in the RE01, RE02, and RE03 Proposed Final Decisions, as described in Section IX, including setting going-in rates for the first rate year and directing Eversource to refile its Targeted System Performance Plan so that it conforms to the IDSP requirements in RE03 PFD No. 2;

(3) alternatively, if it declines to implement PBR as outlined in the reopeners, set the Company's base distribution rates on a conventional cost-of-service basis without adopting the Company's proposed revenue adjustment or capital funding mechanisms;

(4) whether it adopts recommendation (2) or (3), adopt the RE02 performance mechanisms, including the changes described in Section IX, with fixed dollar penalties and, where retained, incentives, effective whether or not a multi-year plan is approved; consider the net risk and earnings opportunity of the adopted PIM portfolio in evaluating the Company's risk when setting its return on equity; require a Comprehensive IDSP in accordance with the final decision in Docket No. 21-05-15RE03; and not approve any mechanism that sets capital recovery from a multi-year forecast until that forecast has been reviewed through a process that conforms to the IDSP requirements; and

(5) state in its Final Decision that nothing decided here sets precedent for the design of multi-year rate plans or prejudges the statewide framework being developed in the reopeners.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Lindsay J. Griffin

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PROFESSIONAL EXPERIENCE

Vote Solar — Senior Regulatory Director, Northeast

Remote / Boston, MA | July 2022 – Present

- Intervene in regulatory proceedings at Northeast state agencies through testimony, discovery, and advocacy to develop distributed energy resource policies that promote equitable access to clean energy
- Translate complex regulatory filings into accessible stakeholder materials and build influential coalitions across diverse groups including environmental justice advocates, consumer advocacy organizations, and industry stakeholders
- Advance regulatory frameworks that address equity, reduce barriers to clean energy adoption, and promote market opportunities for grid flexibility, reliability, and affordability.
- Directed a multi-year regulatory intervention at Connecticut PURA's performance-based regulation proceeding; prepared briefs, technical comments, coalition strategy, and analysis resulting in a new utility compensation reform framework.
- Developed and championed advocacy for two Massachusetts legislative initiatives enabling DER deployment through permitting, interconnection, and utility reform improvements.
- Managed analysis and modeling efforts evaluating pathways to meeting state energy needs through public power by performing gap analysis of climate goals that shaped the core policy demands of a public power campaign.

Commonwealth of Massachusetts – Department of Public Utilities, Electric Power Division

Boston, MA | Economist III | January 2018 – July 2022

- Led development of policy frameworks and legal analysis for Massachusetts clean energy and environmental programs through memoranda and Commission briefings.
- Designed consumer protection policies for the retail electric supply industry through market investigations and enforcement actions.
- Implemented net metering and interconnection standards supporting state solar incentive and renewable energy programs.
- Evaluated energy efficiency and clean energy programs—including Mass Save, demand response, and energy storage pilots—with emphasis on equity and environmental justice.
- Assessed electric utility cybersecurity protections and collaborated with state, regional, and federal agencies on policy implementation.
- Conducted discovery, expert witness cross-examination, and comprehensive record review to support regulatory decision-making.

CivicSolar, Inc. — Account Manager

Boston, MA | April 2016 – January 2018

- Managed sales of solar electric systems for residential and commercial customers, including installers, developers, and property owners.
- Conducted remote site assessments analyzing energy needs, shading, spatial constraints, and electrical requirements to recommend optimal configurations.
- Developed financial proposals evaluating energy usage, project economics, and ROI for PV installations.
- Maintained technical expertise through manufacturer training on emerging technologies.
- Delivered high-quality customer service through proactive communication and issue resolution.

Newport Solar — Remote Site Analyst

North Kingstown, RI | June 2015 – April 2016

- Produced preliminary financial assessments incorporating incentive programs and project economics.
- Used satellite imagery and consumption data to create solar feasibility studies and site assessments.
- Prepared technical drawings including aesthetic layouts, roof diagrams, and single-line electrical schematics for engineering and installation teams.

EDUCATION

University of Rhode Island — Kingston, RI

B.S., Environmental & Natural Resource Economics (Green Markets & Sustainability) — May 2016
B.S., Marine Affairs (Coastal & Marine Policy Management) — May 2016

Leicester High School — Leicester, MA — Graduated May 2012

COURSEWORK & TECHNICAL SKILL

- **NARUC Trainings**
- **Lobbying**
- **Public Speaking: NYSEIA Solar Summit, RE+ Northeast**
- **Community Engagement & Organizing**

ORGANIZATIONS & LEADERSHIP

- **City of Boston Poll Worker**
- **Gay 4 Good - Volunteer**
- **Friendship Works - Volunteer**

PUBLICATIONS & MEDIA FEATURES

Media Features & Articles

- https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ny-power-authority-outlines-green-generation-plan-critics-worry-it-falls-short-85841066
- https://capitolpressroom.org/2024/08/06/promoting-a-sense-of-urgency-for-states-public-renewables/
- https://www.nyserda.ny.gov/About/Newsroom/2023-Announcements/2023-11-28-Governor-Hochul-Announces-More-Than-Two-Gigawatts-of-Community-Solar
- https://www.utilitydive.com/news/connecticut-utility-eversource-performance-incentive-mechanisms/699530/
- https://www.timesunion.com/opinion/article/utilities-credit-customers-promptly-community-18168217.php
- https://www.nationalgridus.com/News/NYSERDA-And-National-Grid-Announce-Round-One-Results-of-Community-Solar-Program-Offering-For-Underserved-New-Yorkers/
- https://www.solarpowerworldonline.com/2025/01/two-new-massachusetts-bills-aim-to-stimulate-distributed-solar-development/
- https://ctmirror.org/2025/02/11/breaking-glass-ceilings-in-climate-policy-why-chair-gilletts-leadership-matters/
- https://commonwealthbeacon.org/energy/massachusetts-based-company-launches-program-to-fund-community-solar-projects/

Reports & Publications

- https://www.ourenergypolicy.org/resources/mind-the-gap-an-estimation-of-the-renewable-energy-needed-to-meet-new-yorks-clean-energy-mandates/
- https://ieeexplore.ieee.org/document/10287706
- https://publicpowerny.org/wp-content/uploads/2024/06/Powering-Up-A-Roadmap-for-Public-Renewables-in-New-York-State-.pdf
- https://drive.google.com/file/d/1n7k_T_xfN88zrUqArDAI5c-Zful9d4oC/view
- https://www.nyseia.org/2023speakers
- https://replusnortheast2024.eventscribe.net/fsPopup.asp?PresentationID=1335831&mode=presInfo

Appendix B: Docket Time Schedules

Chronological Listing of Scheduled Events, PBR Phase I and Reopener Dockets 21-05-15RE01, RE02, and RE03, and Rate Case Application filing

No.	Date	Event	Docket(s)
P1	05/26/2021	Docket Initiated; Notice of Proceeding Issued	21-05-15
P2	12/14/2021	Revised Notice of Proceeding (Strategen retained as consultant)	21-05-15
P3	01/31/2022	Notice Regarding Investigation Timeline (investigation split into two phases)	21-05-15
P4	03/16/2022	Public Listening Session 1	21-05-15
P5	03/17/2022	Staff Concept Paper 1 Issued	21-05-15
P6	04/05/2022	Stakeholder Workshop 1	21-05-15
P7	04/12/2022	Request for Written Comments 1	21-05-15
P8	05/06/2022	Written Comments Due	21-05-15
P9	06/23/2022	Staff Concept Paper 2 Issued	21-05-15
P10	07/14/2022	Stakeholder Workshop 2	21-05-15
P11	07/22/2022	Request for Written Comments 2	21-05-15
P12	08/12/2022	Written Comments Due (Regulatory Assessments)	21-05-15
P13	10/07/2022	Staff Concept Paper 3 Issued	21-05-15
P14	10/24/2022	Stakeholder Workshop 3	21-05-15
P15	11/23/2022	Request for Written Comments 3; Written Comments Filed	21-05-15
P16	12/19/2022	Public Listening Session 2	21-05-15
P17	01/25/2023	Straw Proposal Issued; Request for Written Comments and Briefs	21-05-15
P18	02/01/2023	Stakeholder Workshop 4	21-05-15
P19	02/16/2023	Written Comments and Briefs Due	21-05-15
P20	03/17/2023	Proposed Final Decision Issued	21-05-15
P21	03/31/2023	Written Exceptions Due	21-05-15
P22	04/26/2023	Final Decision Issued (Phase 1 Decision)	21-05-15
1	05/03/2023	Docket Initiated	RE01, RE02, RE03

No.	Date	Event	Docket(s)
2	05/22/2023	Notice of Proceeding Issued	RE01, RE02, RE03
3	06/08/2023	1st Set of Interrogatories Issued	RE02
4	06/09/2023	Requests for Intervenor Status Due	RE03
5	06/22/2023	Working Group Mtg. 1	RE02
6	06/29/2023	1st Set of Interrogatory Responses Due	RE02
7	07/06/2023	Notice Re: Timeline and Docket Process	RE01, RE02, RE03
8	07/12/2023	Notice of Technical Meeting No. 1	RE01
9	07/14/2023	Notice of Technical Meeting #2,#3,#4	RE01
10	07/14/2023	Request for Written Comments #1	RE01
11	07/17/2023	*Final Investigation "Scope" (cancelled)*	RE01
12	07/17/2023	Working Group Meeting 2	RE02
13	07/20/2023	Issue Written Comment Request Set 1	RE02
14	07/27/2023	Working Group Meeting 3	RE02
15	07/28/2023	Staff Presentation published	RE01
16	07/31/2023	Technical Meeting #1	RE01
17	08/09/2023	Revised Notice of Docket Timeline & Docket Process	RE03
18	08/11/2023	Written Comments #1 (MRP)	RE01
19	08/21/2023	Set 1 Written Comments Due	RE02
20	08/23/2023	Technical Meeting #2	RE01
21	08/28/2023	Written Comments #1 (ESM,RDM,Capex/Opex)	RE01
22	08/29/2023	Working Group Meeting 4	RE02
23	09/01/2023	1st Set of Interrogatories Issued	RE01
24	09/05/2023	Technical Meeting #3	RE01
25	09/11/2023	Technical Meeting #1	RE02
26	09/13/2023	Issue Written Comment Request Set 2	RE02
27	09/15/2023	1st Set of Interrogatory Responses Due	RE01
28	09/18/2023	Technical Meeting #4	RE01
29	09/19/2023	*Request for Written Comments #2 (cancelled)*	RE01

No.	Date	Event	Docket(s)
30	09/20/2023	Technical Meeting No. 1	RE03
31	09/29/2023	Written Comments #1 (Final proposals)	RE01
32	10/02/2023	Set 2 Written Comments Due	RE02
33	10/03/2023	*Written Comments #2 (cancelled)*	RE01
34	10/12/2023	Technical Meeting #2	RE02
35	11/08/2023	Technical Meeting No. 2	RE03
36	11/16/2023	Concept Paper or Straw Proposal Issued	RE01
37	11/16/2023	Issue Written Comment Request Set 3	RE02
38	12/12/2023	Technical Meeting #3	RE02
39	12/13/2023	1st Set of Interrogatories Issued	RE03
40	12/15/2023	Set 3 Written Comments Due	RE02
41	12/21/2023	Written Comments Due on Straw Proposal	RE01
42	01/05/2024	1st Set of Interrogatory Responses Due	RE03
43	01/10/2024	Technical Meeting #5	RE01
44	01/11/2024	Technical Meeting No. 3	RE03
45	01/12/2024	3rd Set of Interrogatories Issued	RE01
46	01/26/2024	3rd Set of Interrogatory Responses Due	RE01
47	02/06/2024	Technical Meeting No. 4	RE03
48	02/14/2024	Tech Meeting #6	RE01
49	02/29/2024	4th Set of Interrogatories Issued	RE01
50	03/06/2024	Technical Meeting No. 5	RE03
51	03/14/2024	4th Set of Interrogatory Responses Due	RE01
52	03/14/2024	Issue Straw Proposal & Request for Written Comments	RE02
53	03/20/2024	Technical Meeting #7	RE01
54	03/27/2024	*Technical Meeting #4 (cancelled)*	RE02
55	04/02/2024	*Technical Meeting No. 6 (cancelled)*	RE03
56	04/24/2024	Straw Proposal Written Comments Due	RE02

No.	Date	Event	Docket(s)
57	04/25/2024	5th Set of Interrogatories Issued	RE01
58	05/14/2024	Technical Meeting No. 7	RE03
59	05/15/2024	5th Set of Interrogatory Responses Due	RE01
60	05/15/2024	Written Comments #4 Due	RE01
61	06/07/2024	Technical Meeting #8 - In person	RE01
62	06/10/2024	Technical Meeting #5-in Person	RE02
63	06/11/2024	Technical Meeting No. 8	RE03
64	07/09/2024	2nd Set of Interrogatories Issued	RE03
65	07/18/2024	6th Set of Interrogatories Issued	RE01
66	07/30/2024	2nd Set of Interrogatory Responses Due	RE03
67	08/01/2024	6th Set of Interrogatory Responses Due	RE01
68	08/05/2024	2nd Set of Interrogatories Issued	RE02
69	08/12/2024	Technical Meeting #9- In person	RE01
70	08/16/2024	7th Set of Interrogatories Issued	RE01
71	08/19/2024	2nd Set of Interrogatory Responses Due	RE02
72	08/26/2024	Technical Meeting #6- In person	RE02
73	08/30/2024	7th Set of Interrogatory Responses Due	RE01
74	09/04/2024	3rd Set of Interrogatories Issued	RE02
75	09/13/2024	Technical Meeting #10- In person	RE01
76	09/18/2024	3rd Set of Interrogatory Responses Due	RE02
77	09/26/2024	Technical Meeting #7-In Person	RE02
78	10/01/2024	8th Set of Interrogatories Issued	RE01
79	10/15/2024	8th Set of Interrogatory Responses Due	RE01
80	10/17/2024	Issue Concept Paper	RE03
81	10/24/2024	4th Set of Interrogatories Issued	RE02
82	10/24/2024	Technical Meeting #11- In person	RE01
83	10/28/2024	9th Set of Interrogatories Issued	RE01
84	10/31/2024	Technical Meeting #8-In Person	RE02

No.	Date	Event	Docket(s)
85	11/06/2024	Written Comments Due	RE01
86	11/07/2024	4th Set of Interrogatory Responses Due	RE02
87	11/12/2024	9th Set of Interrogatory Responses Due	RE01
88	11/18/2024	5th Set of Interrogatories Issued	RE02
89	11/18/2024	Technical Meeting #12- In person	RE01
90	11/19/2024	*Technical Meeting No. 9 (cancelled)*	RE03
91	11/19/2024	Written Comments Due	RE03
92	11/25/2024	10th Set of Interrogatories Issued	RE01
93	11/25/2024	Technical Meeting #9-In Person	RE02
94	12/02/2024	5th Set of Interrogatory Responses Due	RE02
95	12/09/2024	10th Set of Interrogatory Responses Due	RE01
96	12/09/2024	Technical Meeting #13 - In Person	RE01
97	12/16/2024	6th Set of Interrogatories Issued	RE02
98	12/16/2024	*Technical Meeting #10-In Person (cancelled)*	RE02
99	12/17/2024	Technical Meeting No. 10	RE03
100	12/23/2024	11th Set Interrogatories Issued	RE01
101	01/08/2025	6th Set of Interrogatory Responses Due	RE02
102	01/10/2025	3rd Set of Interrogatories Issued	RE03
103	01/13/2025	11th Set of Interrogatory Responses Due	RE01
104	01/24/2025	3rd Set of Interrogatory Responses Due	RE03
105	01/30/2025	Technical Meeting No. 11	RE03
106	02/27/2025	Issue Revised Straw Proposal & Request for Written	RE02
107	02/27/2025	Rev. Straw Proposal & Request for Written Comments	RE01
108	03/04/2025	12th Set Interrogatories Issued	RE01
109	03/18/2025	12th Set Interrogatories Due	RE01
110	03/26/2025	Written Comments Due	RE01
111	03/27/2025	Written Comments Due	RE02

No.	Date	Event	Docket(s)
112	03/31/2025	Technical Meeting #14 - In Person	RE01
113	04/02/2025	Technical Meeting #11- In Person	RE02
114	04/04/2025	Issue Straw Proposal	RE03
115	04/07/2025	Technical Meeting #15 - In Person	RE01
116	04/08/2025	*Technical Meeting #12- In Person (cancelled)*	RE02
117	04/10/2025	13th Set Interrogatories Issued	RE01
118	04/21/2025	7th Set of Interrogatories Issued	RE02
119	04/24/2025	13th Set Interrogatories Due	RE01
120	04/28/2025	14th Set Interrogatories Issued	RE01
121	05/01/2025	8th Set of Interrogatories Issued	RE02
122	05/05/2025	7th Set Interrogatories Due	RE02
123	05/08/2025	Written Comments Due - Straw Proposal	RE03
124	05/12/2025	14th Set Interrogatories Due	RE01
125	05/13/2025	Technical Meeting No. 12	RE03
126	05/15/2025	8th Set of Interrogatory Responses Due	RE02
127	05/19/2025	Revised Notice of Technical Meeting	RE01, RE02, RE03
128	05/21/2025	End of Discovery	RE01, RE02
129	05/21/2025	Technical Meeting	RE01, RE02
130	05/21/2025	Technical Meeting No. 13	RE03
131	05/27/2025	Briefs Due	RE01, RE02
132	06/23/2025	Briefs Due	RE03
133	07/14/2025	Distribution of Proposed Final Decision	RE01, RE02
134	08/08/2025	Distribution of Proposed Final Decision	RE03
135	08/15/2025	Written Exceptions Due	RE01, RE02
136	08/28/2025	Written Exceptions Due	RE03
137	09/03/2025	Oral Arguments, if requested	RE01, RE02, RE03
138	10/15/2025	*Regular Meeting/Final Decision (cancelled)*	RE02, RE03

No.	Date	Event	Docket(s)
139	07/07/2026	Updated time schedule for remaining events (no proposed final decision issued)	RE01
	07/14/2026	**CL&P rate case application filed**	**26-05-10**
140	07/17/2026	Proposed Final Decision Issued	RE03
141	07/27/2026	Proposed Final Decision Issued	RE02
142	08/06/2026	Remaining decision events removed from schedule; dates to be announced	RE01, RE02, RE03

Phase I events from Docket No. 21-05-15, April 26, 2023 Decision (Phase 1 Decision), at pages 5–8; Reopener events from PURA time schedules for Docket Nos. 21-05-15RE01, 21-05-15RE02, and 21-05-15RE03 (last revised 8/12/2026), including schedule comments dated 7/7/2026, 7/17/2026, 7/27/2026, and 8/6/2026; Docket No. 26-05-10 time schedule (last revised 9/22/2026). Events scheduled on the same date with the same title in more than one docket are listed once. Cancelled events are shown in italics.

Appendix C: Recommendations

Revenue Adjustment Mechanism Recommendations

The following recommendations reflect the revenue adjustment mechanisms as proposed in the RE01 Proposed Final Decision (July 14, 2025), except where an item is identified as a change discussed in my direct testimony.

1. Adopt a Revenue Cap Formula (rather than a cost-forecast approach) applied to the total revenue requirement (capital and OM&A costs), excluding items funded separately such as the CT-Bar, capital trackers, and PIMs.[1]
2. Set a 4-year MYRP, with the next rate case filed in Rate Year 4.[2]
3. Adopt the CT-Bar with its 6-step calculation methodology, distinguishing Capital Plan from non-Capital Plan additions, subject to downward-only reconciliation and no return on investment until the next rate case's prudency review, with revenue collected for investment later found imprudent returned to customers with carrying charges. As a change from the RE01 PFD (see Direct Testimony, Section IX), the CT-Bar should not fund any capital additions, including the Rate Year 1 CT-Bar additions the RE01 PFD proposed would include in going-in rates, until Eversource has refiled its Targeted System Performance Plan in a form that conforms to the IDSP proposed requirements in RE03 PFD No. 2 and the Authority has reviewed it; the reviewed plan should then provide the Capital Plan input for the remaining rate years. [3]

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[1] PURA Investigation into Revenue Adjustment Mechanisms for a Performance-Based Regulation Framework, Docket No. 21-05-15RE01, Proposed Final Decision, at page 8 (Connecticut Public Utilities Regulatory Authority July 14, 2025); Id at 20-21 & n.19.

[2] Id at 9.

[3] Id at 31-40.

4. Require Eversource to accept the stay-out commitment in writing within 10 days of the decision of the MYRP mechanisms; if it does not, default Eversource to a 1-year rate plan that excludes the Revenue Cap Formula and CT-Bar.[4]
5. Design a Revenue Cap Formula (a) that bases the I-Factor on GDPPI, reset annually using the most recent 4 quarters; (b) that bases the X-Factor on a TFP study using at least three outputs (customer count, delivered energy, and peak demand), with the data and models made available to parties; and that does not permit a negative X-Factor unless supported by a study that meets these requirements (a change from the RE01 PFD; see Direct Testimony, Section IX); (c) that sets any S-Factor in this proceeding based on a benchmarking study, using a simple tiered approach under which a utility shown to be less efficient than its peers receives a larger S-Factor; (d) that follows the Hawaii-PUC-style Z-Factor eligibility criteria with a materiality threshold of 0.75% of the annual revenue requirement, and disallows carrying charges until after the prudency review; and (e) that excludes a G-Factor.[5]
6. Permit capital cost trackers only for discrete, extraordinary cost recovery, each governed by the decision that establishes it.[6]
7. Omit an Efficiency Carryover Mechanism, consistent with the RE01 Proposed Final Decision.[7]
8. Design Earnings Sharing Mechanisms (a) as asymmetrical (upside-only sharing), (b) that excludes dead bands, (c) that excludes tiers, (d) that calculate earnings using the lesser of

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4 Id at 10-11.
5 Id at 22-28.
6 Id at 40.
7 Id at 43.

the authorized or actual carried common equity position, based on average rate base/capitalization ratio, with calendar-year reporting retained, and (e) that exclude PIM rewards/penalties, and exclude disallowed or omitted OM&A costs, from the ROE calculation used for the ESM (excluding depreciation, property tax, GET, and post-test-year debt cost from that exclusion).[8]

9. Continue the revenue decoupling mechanism, with annual reconciliation, and determine in the rate case whether to exclude from reconciliation and sales forecasts any revenues associated with power not restored after an extended service outage.[9]
10. Consider Totex Ratemaking following the finalization of the instant rate case and PBR proceeding.[10]

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8 Id at 47-53.
9 Id at 55; id. at App. A, pp. xii–xiii.
10 Id at 57.

Performance Mechanism Recommendations

The following recommendations reflect the performance mechanisms as proposed in RE02 PFD No. 2 (July 27, 2026), effective whether or not a multi-year rate plan is approved, except where an item is identified as a change discussed in my direct testimony.

1. A Cost Efficiency Scorecard that pairs a "Total Cost" metric (overall EDC financial performance) as the primary measure with six sub-metrics (operating expenditures, controllable Opex, authorized controllable Opex, capital expenditures, capital cost, and total cost), all normalized per customer/line-mile and benchmarked against a 10-year historical average for context.[11]
2. An Inspection & Maintenance System Reported Metric that requires the EDC to publish data from its routine grid inspection and maintenance programs, to increase transparency around infrastructure upkeep.[12]
3. Reliability Cost Metrics carried over from the Authority's 2022 Reliability and Resilience Decision (Docket 17-12-03RE08), organized by reliability program and showing performance, program cost, performance-to-cost ratios, and rate impact, to give context for the Cost Efficiency Scorecard. Cite to "Table 19" template from the Reliability and Resilience Decision.[13]

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[11] *PURA Investigation into Performance Mechanisms for a Performance-Based Regulation Framework*, Docket No. 21-05-15RE02, Proposed Final Decision at 13, (Connecticut Public Utilities Regualtory Authority July 14, 2025); *PURA Investigation into Performance Mechanisms for a Performance-Based Regulation Framework*, Docket No. 21-05-15RE02, Proposed Final Decision No. 2 at 16 (Connecticut Public Utilities Regualtory Authority July 27, 2026).

[12] RE02 PFD No. 2 at 18 (2026).

[13] RE02 PFD No. 2 at 22 (2026).

4. The existing NWS Shared Savings Mechanism, under which EDCs and ratepayers split savings achieved when non-wires solutions are chosen over traditional infrastructure, into the PIMs portfolio without introducing any new penalties or incentives beyond what the mechanism already provides.[14]
5. A Distribution System Losses Reported Metric that quantifies electricity lost in distribution, split into technical losses (physical/engineering) and non-technical losses (e.g., theft, metering error), calculated via an energy-balance method.[15]
6. A DER and NWS Avoided Cost Metric that tracks the system costs avoided or deferred by operational DERs (500 kW and larger) and non-wires solutions (NWS), including avoided energy use and non-energy benefits from those DERs, with avoided costs calculated net of incremental interconnection costs and NWS-related costs valued using the present worth method.[16]
7. A Peak Demand Scorecard, using a three-year (rather than five-year) historical moving average as the benchmark to better reflect recent trends, that tracks four sub-metrics against that benchmark: annual peak demand, monthly peak demand, estimated DER contributions to peak demand, and system load factor.[17]
8. An EV Managed Charging Scorecard that tracks enrollment and performance in the EDCs' EV managed-charging programs, using the two-tier program structure from the annual EV Charging Program dockets (No. XX-08-06).[18]

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14 RE02 PFD No. 2 at 25 (2026).
15 RE02 PFD No. 2 at 33 (2026).
16 RE02 PFD No. 2 at 19 (2026).
17 RE02 PFD No. 2 at 28 (2026).
18 RE02 PFD No. 2 at 30 (2026).

9. A DER Services Reported Metric that tracks enrolled assets, total megawatts (MW) enrolled, and MW of peak-demand reduction across four DER programs: Energy Storage Systems, Smart Thermostats, Commercial & Industrial Demand Response, and EV Managed Charging.[19]
10. An Energy Storage Performance Metric that tracks whether the EDCs' energy storage system (ESS) dispatch events actually align with real ISO-New England system peaks, plus MW of peak demand avoided and associated dollar savings from peak shaving.[20]
11. A downside-only System Reliability PIM measuring blue-sky (non-major-storm) System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), excluding CAIDI to reduce redundant reporting. This PIM should be benchmarked to a fixed 5-year historical average, with penalties triggered once performance exceeds 1 standard deviation from that average. Penalty amounts should be set no lower than the maximum SAIDI and SAIFI penalties the Company proposed in Exhibit CLP-ELP-3 (see Direct Testimony, Section VI).[21]
12. A Customer Reliability Scorecard that tracks the four sub-metrics proposed in RE02 PFD No. 2 (CEMI-5, percent of repeat CEMI-5 customers, CELID-6, and percent of repeat CELID-6 customers), averaged into a composite score and compared to the fixed 2020–2024 historical average, with no financial reward and with the option to elevate it to a downside-only PIM once sufficient data are available. <u>This is a change from the upside-only potential PIM recommendation in RE02 PFD No. 2</u> (see Direct Testimony, Section

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19 RE02 PFD No. 2 at 35 (2026).
20 RE02 PFD No. 2 at 36 (2026).
21 RE02 PFD No. 2 at 38-42 (2026).

IX). If the Authority nonetheless attaches a reward, the reward threshold should be the historical average minus one standard deviation, so that the Company is rewarded only for improvement beyond normal year-to-year variation.[22]

13. An All-in SAIDI Scorecard that tracks total SAIDI including major storms, benchmarked against both a 10-year and a 5-year historical rolling average, with room for an explanatory narrative on storm severity/tree-trimming conditions.[23]
14. A Major Storm Reported Metric that requires post-storm restoration data broken out by zip code and customer class, purely for backward-looking transparency.[24]
15. Five-Year Outage History, Circuit-Level Performance, Voltage Irregularities, and Power Quality Reported Metric that include outage history by cause over 5 years; circuit-level reliability performance; voltage irregularities/power surges affecting 10+ customers; and general power-quality data.[25]
16. An Equitable AMI Scorecard that tracks how Advanced Metering Infrastructure (AMI) is deployed and used among financial-hardship customers, including the percentage of hardship customers with AMI who are disconnected for non-payment (benchmarked against hardship customers without AMI) and enrollment in AMI-dependent offerings like time-of-use rates.[26]

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22 RE02 PFD No. 2 at 42-46 (2026).
23 RE02 PFD No. 2 at 48 (2026).
24 RE02 PFD No. 2 at 49 (2026).
25 RE02 PFD No. 2 at 50 (2026).
26 RE02 PFD No. 2 at 53 (2026).

17. A Power Restoration After Major Storms Reported Metric that tracks restoration speed after major storms in distressed municipalities (using the state Dept. of Economic and Community Development's list, rather than census-block data), for transparency only.[27]
18. An Underserved Communities Inclusion Reported Metric that tracks participation of distressed municipalities, low-income customers, and underserved communities in the RRES, NRES, SCEF, and ESS programs.[28]
19. An Environmental Justice Reliability Reported Metric that tracks reliability performance (e.g., outage frequency/duration) specifically within designated Environmental Justice communities.[29]
20. A GHG Emissions Scorecard that tracks the EDC's Scope 1, 2, and 3 greenhouse gas emissions and emissions intensity, benchmarked against a 2019 reference year.[30]
21. A Clean Energy Program Attrition Reported Metric that tracks withdrawals/attrition from the Non-Residential Renewable Energy Solutions (NRES) and Shared Clean Energy Facility (SCEF) programs.[31]
22. A SF_6 Reported Metric that tracks sulfur hexafluoride leaks, aligned with the EDCs' existing EPA filings rather than a new separate reporting format.[32]
23. A Beneficial Electrification Reported Metric that tracks trends in electrification of previously fossil-fuel-powered end uses (e.g., heating, transportation).[33]

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27 RE02 PFD No. 2 at 55 (2026).
28 RE02 PFD No. 2 at 57 (2026).
29 RE02 PFD No. 2 at 59 (2026).
30 RE02 PFD No. 2 at 62 (2026).
31 RE02 PFD No. 2 at 65 (2026).
32 RE02 PFD No. 2 at 67 (2026).
33 RE02 PFD No. 2 at 68 (2026).

24. A Time-Varying Rate Scorecard that tracks, by customer class, the number and percentage of customers participating in time-varying rates and the load reduced or shifted because of TVR adoption, with enrollment targets as AMI deployment is completed and participation reported separately for LMI and non-LMI customers, or at a minimum a Reported Metric that converts to a Scorecard. This is a change from the Reported Metric proposed in RE02 PFD No. 2 (see Direct Testimony, Section IX).[34]
25. A Customer Data Engagement Reported Metric that tracks how many customers actively access/engage with their AMI usage data (e.g., through online portals), and enable data sharing with third parties.[35]
26. A Community Engagement Scorecard built on the three consolidated sub-metrics in RE02 PFD No. 2 (number of activities, public participation, and actionable outcomes), with targets for outreach activity and an equity sub-metric for Environmental Justice community representation on advisory boards, or at a minimum a Reported Metric with a stated path to a Scorecard. This is a change from the Reported Metric in RE02 PFD No. 2 (see Direct Testimony, Section IX).[36]
27. A symmetrical Level 1 DER Interconnection PIM measuring the combined pre- and post-construction timeline for small (Level 1) DER interconnection applications, using a 4-step calculation and a 3-year historical average as the benchmark; excluding non-working days and periods when applications sit with the developer.[37]

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34 RE02 PFD No. 2 at 70-71 (2026).
35 RE02 PFD No. 2 at 73 (2026).
36 RE02 PFD No. 2 at 74-76 (2026).
37 RE02 PFD No. 2 at 79 (2026).

28. A Level 2 DER Interconnection Scorecard that tracks the average number of business days in EDC-controlled processing steps for fast-track Level 2 DER interconnection projects, using the four-step calculation in RE02 PFD No. 2, benchmarked against the EDC interconnection guidelines and a five-year historical average. As a change from RE02 PFD No. 2, the Authority should consider elevating the Scorecard to a PIM if Level 2 processing times lengthen while Level 1 times improve (see Direct Testimony, Section IX).[38]
29. A Customer Satisfaction Scorecard that tracks satisfaction via Likert-scale survey ratings across three touchpoints: call-center support, the interconnection process, and service interruptions, segmented by customer class and (for the interruptions category) using IEEE-defined Major Event Days to avoid skewing from minor storms.[39]
30. An Existing Customer Service Metric that tracks nine call-center sub-metrics, including average speed of answer, average handle time, abandoned calls and abandoned call rate, first call resolution rate, and quality assurance score, reported annually using existing EDC data.[40]
31. A Customer Inquiries Scorecard that tracks the volume/type of customer complaints (categorized by subject, e.g., pricing or interconnection speed, rather than by "preventable" vs. "justified"), contextualized against average customer bill amounts.[41]
32. An Affordability & Disconnection Minimization Scorecard that tracks the annual percentage change in non-payment-related service terminations for non-hardship

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38 RE02 PFD No. 2 at 79-81(2026).
39 RE02 PFD No. 2 at 83 (2026).
40 RE02 PFD No. 2 at 89 (2026).
41 RE02 PFD No. 2 at 87 (2026).

residential customers, reflecting increased participation in programs like the Low-Income Discount Rate (LIDR) and the Matching Payment Program (MPP).[42]

33. An Affordability & Electricity Burden Scorecard that measures the share of household income spent on electricity specifically (as opposed to total energy burden), using Dept. of Social Services data (average household size of 1.8, rounded to 2) and DSS income-eligibility-tier midpoints to estimate income.[43]
34. An Accounts Receivable and Uncollectibles Scorecard with five sub-metrics (average residential monthly arrears, residential accounts receivable, actual residential write-offs, the allowed uncollectible rate, and accounts receivable over 60 days as a percentage of revenue over a rolling 12-month period), benchmarked to 2023 and reported in quarterly segments.[44]
35. LIDR Implementation Reported Metrics on enrollment, usage patterns, energy burden, and customer movement between tiers within the state's Low Income Discount Rate program, aligned with the recent LIDR Modification Decision.[45]

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42 RE02 PFD No. 2 at 90-95 (2026).
43 RE02 PFD No. 2 at 97 (2026).
44 RE02 PFD No. 2 at 100.
45 RE02 PFD No. 2 at 101 (2026).

Integrated Distribution System Planning Elements Recommendations

The following recommendations reflect the IDSP requirements as proposed in RE03 PFD No. 2 (July 17, 2026), except where an item is identified as a change discussed in my direct testimony.

1. A planning document built around the following six steps of integrated planning, such as to: (a) assess system needs, (b) identify and evaluate solutions (wires and non-wires), (c) select solutions, (d) develop capital and long-term investment plans, (e) engage stakeholders throughout, and (f) file the plan for Authority review and approval.[46]
2. A ten-section document structure covering: an executive summary; planning policy; current state of the system; IDSP methodology; stakeholder engagement and social equity; load forecasting; grid needs assessment; solution selection process; a capital investment plan covering a ten-year planning horizon; and a long-term strategic plan covering the period beyond ten years, together with a consolidated checklist of every content requirement.[47]
3. A single "Joint Working Group" made up of the utility, PURA staff, the Office of Consumer Counsel, and interested stakeholders, serving as the central forum for engagement on the IDSP throughout its development, rather than separate ad hoc stakeholder processes for each section.[48]

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46 *PURA Investigation into the Establishment of Integrated Distribution System Planning within a Performance-Based Regulation Framework*, Docket No. 21-05-15RE03, Proposed Final Decision at 11 (Connecticut Public Utilities Regulatory Authority Aug. 8, 2025); PURA Investigation into the Establishment of Integrated Distribution System Planning within a Performance-Based Regulation Framework, Docket No. 21-05-15RE03, Proposed Final Decision No. 2 at 11 (Connecticut Public Utilities Regulatory Authority July 17, 2026).

47 RE03 PFD No. 2 at 11-14, Appendix A.

48 RE03 PFD No. 2 at 18, 22.

4. An EDC-developed data-sharing protocol, subject to Authority review and approval and modeled on the NWS Process non-disclosure agreements, for sharing planning data (load, hosting-capacity, and system data) with Joint Working Group members, so that stakeholders without utility-level access can meaningfully participate without exposing commercially sensitive or security-sensitive information.[49]
5. A two-phase engagement approach: first, substantive stakeholder input into planning decisions, and second, broader public education and outreach about the plan and its impacts.[50]
6. A requirement that Eversource document any relevant social equity metrics and considerations factored into planning and solution selection, and include in the IDSP's Stakeholder Engagement and Social Equity chapter a Social Equity Strategy subsection that identifies the equity metrics it uses and explains how they influence planning and investment decisions.[51]
7. A requirement that EDCs convene a "Forecast Working Group" as a sub-group of the JWG to develop the load forecast underlying the plan, including hourly (8,760-hour) load forecasts and appropriate data protections for customer-level information used in the forecast. Furthermore, there should be a requirement for at least three scenarios (low/middle/high), each developed at the system, planning region, substation, and feeder levels, with the middle scenario designated as the baseline for planning purposes.[52]

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49 RE03 PFD No. 2 at 20.
50 RE03 PFD No. 2 at 18.
51 RE03 PFD No. 2 at 22, 24, 51.
52 RE03 PFD No. 2 at 30, 32.

8. A section identifying where and why the grid needs investment, presented in a tabular format organized by region/circuit rather than as a narrative, so that needs can be compared consistently across the service territory.[53]
9. A Grid Needs Assessment that is built from several required sub-analyses: a steady-state (loading/thermal) analysis, an N-1 contingency analysis (system performance with one element out of service), a reliability analysis, and a resiliency analysis.[54]
10. A Hosting Capacity sub-analysis showing how much additional distributed energy resource (DER) capacity the grid can accommodate, and a DER Interconnection Queue / Interconnection Plan sub-analysis addressing the backlog and cost-allocation treatment of pending interconnection requests.[55]
11. A requirement that EDCs evaluate both wires (traditional) and non-wires solutions (NWS) to identified grid needs using the existing NWS Process and its benefit-cost analysis (BCA) methodology as the common evaluation framework, rather than a separate bespoke IDSP evaluation method.[56]
12. A tiered cost-effectiveness screen for solutions, combining cost thresholds carried over from the NWS Process with an evaluation approach where smaller, lower-cost projects get a lighter-touch review while larger investments get fuller BCA scrutiny.[57]
13. A formally defined set of "least-regrets planning principles" favoring solutions that perform reasonably well across a range of future scenarios (load growth, DER adoption,

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53 RE03 PFD No. 2 at 40.
54 RE03 PFD No. 2 at 40-42.
55 RE03 PFD No. 2 at 40-42.
56 RE03 PFD No. 2 at 52.
57 RE03 PFD No. 2 at 52.

policy change) rather than being optimized for a single forecast that Eversource must apply as a qualitative review factor when selecting among solution options.[58]

14. A required standard format for documenting the solutions-identification, evaluation, and selection process within the IDSP, so that reviewers can trace how each grid need was matched to a solution and why.[59]
15. A section that categorizes investments by grid-need type and presents them via a Summary Table, Explanatory Narrative, and Individual Project Listing Table Appendix.[60]
16. An explorative planning approach for the 10+ year horizon, require a Long-Term Plan Working Group with a narrative demand assessment, data exchange, and scenarios spanning both meeting and missing decarbonization targets. The working group should convene at least twice in the 12 months before each IDSP filing, with the membership specified in RE03 PFD No. 2. The long-term plan should be illustrative rather than binding and include a Strategic Planning narrative, with integrated gas-electric planning addressed in a separate proceeding.[61]
17. A requirement that the full IDSP is refiled every 4 years (aligned with the Multi-year Rate Plan duration proposed herein), submitted 3-6 months ahead of the corresponding rate case (or within 18 months of the final RE03 decision, whichever is earlier) so its investment conclusions can feed into rate-case planning.[62]

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58 RE03 PFD No. 2 at 54-55.
59 RE03 PFD No. 2 at 51.
60 RE03 PFD No. 2 at 60.
61 RE03 PFD No. 2 at 65-67.
62 RE03 PFD No. 2 at 72-75, 78.

18. A requirement to file an annual update 3 months after the close of each rate year, made up of two parts: an "Entering Service Review" (confirming which planned projects actually went into service) and an "Annual Adjustment Filing" (updating the plan for material changes since the last Comprehensive Filing). This filing should explicitly flag any major variances from the Comprehensive Filing in this annual update, and times the concurrent JWG/Public Engagement activity to align with this annual cycle.[63]
19. A direction that Eversource refile its Targeted System Performance Plan, as a compliance filing in this docket or in a subsequent docket, so that it conforms to the IDSP requirements in RE03 PFD No. 2, with the reviewed plan serving as the interim basis for CT-Bar capital funding until Eversource files its first Comprehensive IDSP and that plan completes the review process established in the final decision in Docket No. 21-05-15RE03. This is a change specific to this case (see Direct Testimony, Section IX).[64]
20. Building on recommendations 9 and 10, a requirement that Eversource evaluate using N-1 capacity reserve to host DER, through automatic tripping, curtailment, or other smart grid solutions during contingency events, as part of its refiled Targeted System Performance Plan and its Comprehensive IDSP, and reflect the results in its hosting capacity maps. This is a change specific to this case (see Direct Testimony, Section IX).[65]

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63 RE03 PFD No. 2 at 74-75.
64 RE03 PFD No. 2 at 9, 73–75 & App. A; RE01 PFD at 33, 40.
65 RE03 PFD No. 2 at 35, 41–43; Case 24-E-0322 et al., Order Adopting Terms of Joint Proposal and Establishing Rate Plans (N.Y. Pub. Serv. Comm'n Aug. 14, 2025), at 56–57, 106.