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March 14, 2025

Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051

Re: Docket No. 24-12-05, PURA Procedural Review of the Annual Rate Adjustment Mechanisms of the Connecticut Light and Power Company and The United Illuminating Company, Notice of Request for Written Comments

Dear Mr. Gaudiosi:

The Office of Consumer Counsel ("OCC") submits[1] these comments in response to the Public Utilities Regulatory Authority's ("Authority") Notice of Request for Written Comments, issued in the above-captioned proceeding on January 17, 2025. OCC thanks the Authority and all other stakeholders for the indulgence of OCC's Motion No. 3, which provided us the necessary time to retain Synapse Energy Economics ("Synapse") as a consultant in this proceeding to assist us primarily with cost allocation and rate design issues, and to work with Synapse to prepare these comments.

OCC agrees with the impetus of the docket and appreciates the opportunity to comment on the topics. As the electric distribution companies ("EDCs") and the Authority have established, some Rate Adjustment Mechanism ("RAM") cost component allocations are not aligned with cost causation, are overly complex, and are allocated to customers differently by EDC. Furthermore, these cost allocation approaches may be subject to wide variances causing rate shock for customers.

OCC therefore provides these comments which recommend changes to better align cost allocation with cost causation, improve consistency among EDCs methodologies to relevant annual adjustments, simplify and streamline cost allocations, make cost allocation more transparent, and mitigate future rate shock. In a minority of instances these priorities are in conflict, in which case OCC believes rate shock mitigation and simplicity should be prioritized over strict adherence to cost causation principles. OCC is still developing our position on certain topics and we are in the process of issuing discovery. Therefore, OCC reserves the right to review the responses to discovery, and EDC and other stakeholder Set 1 comments, and further develop and modify our recommendations in our future comments.

We address each of the Notice's prompts as follows:

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[1] Comments in response to Prompts 1 and 2 were drafted with substantial assistance from Synapse Energy Economics, OCC's consultant in this proceeding.

1. *In the August 16, 2023 Final Decisions in Docket Nos. 23-01-03, PURA Annual Review of the Rate Adjustment Mechanisms of The Connecticut Light and Power Company Final Decision (2023 Eversource RAM Decision) and 23-01- 04, PURA Annual Review of the Rate Adjustment Mechanisms of The United Illuminating Company (2023 UI RAM Decision, together 2023 RAM Decisions), the Authority began to review the EDCs' current RAM component cost allocation factors and methodologies for two primary reasons (Cost Allocation Objectives): (1) to conduct a comprehensive review of the Company's cost allocation methodologies for their adherence to cost causation principles and other rate setting principles; and (2) to identify potential opportunities for improvement and standardization of cost allocation and rate design methodologies between the two EDCs. 2023 Eversource RAM Decision, pp. 27-31; 2023 UI RAM Decision, pp. 26-31.*

    a. *Comment on the extent to which the EDCs' existing NBFMCC, SBC, and RDM cost allocation methodologies achieve the Cost Allocation Objectives. Additionally, to the extent relevant, provide comments regarding the extent to which the EDCs' existing cost allocation methodologies achieve the Cost Allocation Objectives for any other of the RAM rate components.*
    b. *If warranted, propose changes to the EDCs' existing cost allocation methodologies that could better achieve the Cost Allocation Objectives.*
    c. *Provide recommendations on other cost allocation methodologies not contemplated in the 2023 RAM Decisions that might more effectively achieve the Cost Allocation Objectives.*

Table 1 provides a summary of current EDC methodology for allocating the Revenue Decoupling Mechanism ("RDM"), Non-Bypassable Federally Mandated Congestion Charge ("NBFMCC"), and System Benefits Charge ("SBC") and OCC's recommended changes, if any.

Table 1: Summary of current EDC RDM, NBFMCC, and SBC cost allocation methodology and OCC's recommended changes

RAM Rate Components	Cost Allocation Methodology		
	Eversource - Current	**UI - Current**	**OCC Recommendation**
RDM	Annual energy (kWh)	Annual energy (kWh)	Annual energy (kWh)
NBFMCC			
New England Grid Operator Costs	Demand (12CP)	Demand (1CP)	Annual demand (12CP)
Mandated Energy Purchases			Annual energy (kWh)
Customer Produced Energy			Annual energy (kWh)
Misc. & Other Mandates			Annual energy (kWh)
SBC	Annual energy (kWh)	Annual energy (kWh)	Annual energy (kWh)

RDM

The RDM is an annual true-up mechanism that reconciles actual base distribution revenues to the revenue requirements approved in the EDCs' most recent rate cases. On an annual basis, each EDC reconciles any under- or over-recovery between its approved annual revenue requirement to the actual distribution revenues collected.[2] The RDM revenue requirement is allocated across the rate classes based on the total class energy usage (kWh).

UI indicated previously that the use of annual energy sales to determine a single RDM rate for all kWh sales is not based on cost causation principles.[3] UI noted that there may be more revenue collected from some rate schedules and less from other rate schedules than if the RDM revenues were determined using intra-class allocations. In its 23-01-03 decision, the Authority noted it was inclined to implement changes to the RDM cost allocation and rate design methodologies to better reflect cost causation principles. Specifically, the Authority stated its intent to explore utilizing the proportional class revenue allocation to apportion RDM revenues. The Authority also stated its interest in investigating allocation of the RDM revenue requirement between

[2] Final Decision in 23-01-03, p. 30.
[3] Final Decision in 23-01-04, pp. 29-30.

demand and kWh charges based on the proportion of base distribution revenue allocated to such charges for each customer class.[4]

The Authority's 23-01-03 and 23-01-04 decisions also state that it "does not, […] plan to explore an approach that would maintain any over- or under-collection of base distribution revenues within a given customer class as such an approach may result in large over- or under-collections that would cause customer rate shock."[5] OCC agrees that avoiding rate shock is an important rate design principle that should guide the Authority's decision on this issue. If anything, significant volatility in the RDM over consecutive years likely indicates the use of inaccurate or unreliable sales forecasts. Therefore, emphasis should be placed on sales forecast methodologies to the extent RDM impacts become an issue, and the current cost allocation methodology (apportioning costs according to sales by class) should be maintained on the basis of gradualism and avoiding rate shock, which are bedrock rate-setting principles as discussed below in response to Prompt Number 3.

NBFMCC

The NBFMCC consists of multiple cost components, the revenue requirement of which are summed into this single charge on customer bills. Eversource allocates NBFMCC costs based on class peak demand in each month (12CP) while UI uses each classes' annual peak load (1CP).

These cost allocation approaches do not align with the Cost Allocation Objectives. In particular, the approaches do not align with adherence to cost causation principles and standardization across the EDCs. In Docket 23-01-03, the Authority asked Eversource to categorize the multitude of costs more granularly and propose different cost allocation methodologies.[6] In LFE1, Eversource identified four categories of costs within NBFMCC for which it proposed cost allocation methodologies: (1) New England grid operator costs; (2) mandated energy purchases, (3) customer produced energy, and (4) miscellaneous and other mandates. Eversource proposed to allocate three of these cost categories based on class energy use (kWhs): mandated energy purchases, customer produced energy, and miscellaneous and other mandates. Eversource proposed to allocate New England grid operator costs based on 12CP.

A similar exercise was conducted by UI in its rate case. UI proposed the same energy cost allocator as Eversource for New England grid operator costs (12CP) and customer produced energy costs. For mandated energy purchases, however, UI proposed cost allocation based on energy for most of the costs and determined five line items (out of 43) should be allocated based on 1CP within this cost category. This proposal contrasts with Eversource's proposal of allocating all mandated energy purchases on the basis of energy sales. Further, UI proposed to allocate miscellaneous and other mandate costs based on a mix of customer count and energy sales, depending on the line item. This proposal contrasts with Eversource's proposed sales

[4] Final Decision in 23-01-03, p. 31.
[5] Final Decision in 23-01-04, p. 30
[6] Final Decision in 23-01-03, p. 28.

allocator.[7] **Table 2** below shows Eversource's and UI's proposed cost allocation methodologies for each category of NBFMCC costs.

Table 2: Eversource and UI proposed cost allocation methodologies for NBFMCC cost categories

	Eversource - Proposed	UI - Proposed
New England Grid Operator Costs	12 CP	12 CP
Mandated Energy Purchases	Energy	1CP / Energy
Customer Produced Energy	Energy	Energy
Misc. & Other Mandates	Energy	Customer count / Energy

Source: Eversource exhibit in 23-01-03, "LFE_01_LFE_001_1_Q_LFE_001, Attachment 1;" UI exhibit in 23-01-04, "2023-03-02 Exhibit Z Unbundling of the NBFMCC Rates #23-01-04."

The Authority stated it was inclined to adopt some version of these proposals.[8]

OCC agrees with Eversource's proposal to allocate mandated energy purchases, customer produced energy, and miscellaneous and other mandates based on sales. The primary cost causation driver of mandated energy purchases and customer produced energy is sales. The primary benefit to customers is energy, as opposed to serving coincident or non-coincident peak load. While the miscellaneous and other mandates category includes a variety of cost drivers, the majority are energy-related according to both EDCs.[9] Several are policy-related costs that are intended to confer benefits broadly across classes, which is best accomplished through an allocation on the basis of energy as we discuss further in the SBC section below.

UI may be correct that a few line items within these three cost categories may be more appropriately related to a different allocator than sales.[10] However, utilizing sales as the basis for allocating all costs within these categories is a reasonable approach to promote greater simplicity and transparency in ratemaking as well as better alignment across the EDCs. Further, for the miscellaneous and other mandates category, it is not clear that customer count is a more appropriate allocator for the line items highlighted by UI. For example, the two largest cost categories in UI's exhibit with proposed allocations to customer count (representing 84 percent of costs in the year shown) are "Storm Resiliency Allocation," and "Energy Independence Act

[7] UI Exhibit in 23-01-04, "2023-03-02 Exhibit Z Unbundling of the NBFMCC Rates #23-01-04," tab Exhibit Z p 2 of 11 Allocators.
[8] Final Decision in 23-01-03, p. 28.
[9] See Eversource's determination in column Q of Exhibit in 23-01-03 "LFE_01_LFE_001_1_Q_LFE_001, Attachment 1;" UI's exhibit, page 2, "2023-03-02 Exhibit Z Unbundling of the NBFMCC Rates #23-01-04."
[10] We do not dispute that the line items in UI's mandated energy purchases for which the utility proposes 1CP appear to be capacity related.

Costs." It is not clear to OCC that the number of customers in a given class is a better allocator for these costs than sales.

SBC

SBC primarily recovers the costs associated with customers designated as hardship uncollectible expenses and discounts for customers who qualify for income-based programs. SBC also includes the cost of the Energize Connecticut customer energy efficiency loan program. Eversource and UI use a similar approach of including hardship uncollectible expenses within the SBC, and the Authority has ordered both utilities (UI in Docket No.21-01-04 and Eversource in Docket No. 15-03-01) to record uncollectible expenses for all hardship receivables that have aged over 180 days. Eversource claims that the increase in hardship uncollectible expenses occurred due to: (1) COVID-19 and the continued extension of the disconnection moratorium for financial hardship and/or medically protected customers, (2) an increase in electric supply or standard service rates in 2023, and (3) a reduction in direct energy assistance funding.[11]

If a customer pays an outstanding bill designated as a hardship uncollectible expense, the payment would be credited to customers through the annual RAM proceeding as an offset to hardship uncollectible debt. The EDCs claim that they are incentivized to collect these costs as opposed to writing them off from the accounting books because these costs represent previously incurred expenses. Eversource states that for financial hardship or medically-protected customer expenses to be designated as a write-off, their service must be terminated.[12] However, given the moratorium on service shut-offs for nonpayment for customers, the EDCs have a growing reserve balance on hardship uncollectible expenses that far exceed annual net write-offs.

Eversource and UI take different approaches to allocation of SBC costs across customer classes. While Eversource charges each customer class according to the classes' contribution to these costs, UI allocates the total costs based on class sales.[13] OCC agrees with the Authority's initial assessment, to align the two EDCs based on UI's energy cost allocator:

> "the Authority is inclined to implement some version of UI's SBC revenue allocation methodology for both EDCs <u>as an energy-based allocator is both an appropriate mechanism for allocating costs for the overall SBC rate and has been consistently relied upon to allocate public policy costs since it generally reflects the proportional contribution of each rate class to the overall revenue requirement</u>."[14]

We agree with the Authority that both EDCs should allocate SBC costs based on energy, as costs within the SBC are incurred to support public policy goals attributable to all classes. These costs should therefore be allocated on a broad basis to all customer classes, which the energy allocator achieves. Furthermore, allocating these costs to all customers will help protect residential customers from rate shocks in the event the balance of hardship uncollectible expenses increases

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[11] Joint Testimony of Jessicaa Cain, Dan Traynor, and Brandan O'Brien on Behalf of the Connecticut Light and Power Company d/b/a Eversource Energy, at 9
[12] *Id,* at 9expansion
[13] Final Decision in 23-01-03, p. 29.
[14] Emphasis added. *Id.*

due to either economic conditions, general affordability of rates, changes to policies and discount rates that provide support low-income customers, or other factors.

We note that broad-based allocation is common practice for these types of costs in other jurisdictions. The following states allocate costs that support low-income customers to all other rate clases including the commercial/industrial and residential classes:

- PEPCO in Washington, D.C.: The Residential Aid Discount Surcharge Rider ("RAD") recovers the costs associated with funding discounts for those participating in the RAD program from all customers.[15]
- National Grid in Massachusetts: Implemented a Residential Assistance Adjustment Provision that is allocated to the Company's rate classes by applying to the Distribution Revenue Allocator.[16]
- Multiple gas utilities in Illinois: Ameren Illinois, Nicor Gas, North Shore Gas, and Peoples Gas offer a low-income discount rate ("LIDR")program for customers whose incomes are at or below 300 percent of the Federal Poverty Line. The LIDR is allocated to all classes, including residential, commercial, and industrial customers.[17]

2. *Comment on each EDC's methodology for allocating non-hardship uncollectible expenses and the relationship between such expenses and each of the applicable RAM components. 4 Provide recommendations on how to best align the methodologies used by the EDCs under a single methodology that is equitable to all ratepayers.*

Non-hardship uncollectible expenses are apparently calculated differently by EDC, with Eversource netting a forecast against actuals and UI developing an estimate based on historical data. Non-hardship uncollectible expenses are then recovered through several rate components, including the GSC, base distribution rates, ESI, and NBFMCC, though the rate components and recovery approach differs by EDC. UI recovers non-hardship uncollectible expenses in the TAC[18] and Eversource does not.[19]

Both EDCs allocate some portion of non-hardship uncollectible expenses to the GSC in a similar way, with some potential minor differences. For Eversource, actual non-hardship net write-offs

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[15] “”Rate Schedules for Electric Service in the District of Columbia. Rates and Regulatory Practices Group." n.d. Accessed March 11, 2025. Available at: https://www.pepco.com/cdn/assets/v3/assets/bltbb7c204688a1a6a8/blt1592c0ff5185f738/67cf342e8bcc6514cb086f7a/UG_Rider_and_PSOS_Clean_eff_March_1_2025.pdf?branch=prod_alias.

[16] *Residential Rate Adjustment Provision*. Massachusetts Electric Company Nantucket Electric Company. n.d. Accessed March 11, 2025. Available at: https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/res_assist_adjmt.pdf

[17] Elizabeth. (2024, October 4). *CUB Q&A: The Low-Income Discount Rate (LIDR) program | Citizens Utility Board*. Citizens Utility Board. Available at: https://www.citizensutilityboard.org/blog/2024/10/04/cub-qa-the-low-income-discount-rate-lidr-program/.

[18] Final Decision in 24-01-03, pp. 25-26.

[19] PURA. Docket No. 24-01-03. PURA Annual Review of the Rate Adjustment Mechanisms of The Connecticut Light and Power Company. *Eversource Written Comments*. January 17, 2024. Available at: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/f4ff6ca7a9d0d71585258aa700745333/$FILE/Docket%20No.%2024-01-03-Eversource%20Written%20Comments-1.17.24-Final.pdf

are allocated to the GSC using an allocation percent calculated based on the prior quarter GSC billed revenues divided by total retail billed revenues. UI notes a similar approach, though the historical time period used to develop the allocator is 12 months instead of 3 months.[20] The Authority previously indicated a preference for basing GSC non-hardship uncollectible expenses on actual write-offs,[21] rather than estimates. OCC agrees with this approach. Also, the Authority stated interest in making the methodology to allocate non-hardship uncollectible expenses to the GSC consistent across EDCs, and we also agree.[22] Also, the historical time periods used to develop the allocation should be consistent across EDCs.

Eversource allocates the remaining portion of non-hardship uncollectible expenses to base distribution rates and UI allocates the remaining portion between the TAC and base distribution rates.. The allocation of the remaining portion of these expenses should be similar between the EDCs. Also, we do not understand how Eversource is not authorized to collect these expenses through the TAC and UI is authorized to do so.

Eversource stated that the non-hardship uncollectible expense included in the ESI is an incremental charge associated with capital projects and enhanced tree trimming O&M such as for "System Resiliency, Enhanced Tree Trimming, 2017 Overestimate of Plant Additions, Capital Spent over $270 million for Rate Years One through Three, and Core Capital up to $300 million post Rate Year Three".[23] The non-hardship uncollectible expense included in Eversource's NBFMCC is an incremental charge associated with Authority -approved programs in other public policy dockets such as DER Portal, DER Map, SCEF, and CT Residential Solar programs.[24]. UI does not recover non-hardship uncollectible expenses through its ESI or NBFMCC.[25]

Table 3 below summarizes the EDCs' current approach to cost recovery for non-hardship uncollectible expenses and OCC's recommendations.

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[20] Final Decision in 24-01-03, pp. 25-26.
[21] The method to calculate the GSC non-hardship uncollectible expenses was modified by the PURA final decision in Docket No. 23-01-03 to be based upon the actual amount of net non-hardship customer account write-offs.
[22] Final Decision in 23-01-03, p. 26.
[23] PURA. Docket 23-01-03. *Eversource Compliance Order No. 9. Appendix A.* November 15,2023. Available at: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/e60ed5e915f2cdb485258a68006b6978/$FILE/Compliance%20with%20Order%20No.%209%20-%20Appendix%20A.pdf
[24] Id.
[25] Final Decision 23-01-04, pp. 25-26.

Table 3. Summary of EDC current non-hardship uncollectible expense cost allocation methodology and OCC's recommended changes

RAM Rate Components	Cost Allocation Methodology		
	Eversource - Current	**UI - Current**	**OCC Recommendation**
GSC	Net non-hardship customer account write-offs; previous three months of GSC revenues / total revenues	Estimate of the current uncollectible expense based on the historical percentage of non-hardship uncollectibles * previous 12 months of GSC revenues / total revenues	Net non-hardship customer account write-offs * GSC revenues / total revenues (for a historical period that is consistent across EDCs)
TAC	N/A	Remaining estimate * previous 12 months of transmission revenues / total transmission and distribution revenues	To be determined
Base Distribution Rates	Remaining net non-hardship customer account write-offs	Remaining estimate, after allocation to TAC	Remaining net non-hardship customer account write-offs * GSC revenues / total revenues (for a historial period that is consistent across EDCs)
ESI	Incremental charge for capital projects and enhanced tree trimming O&M	N/A	To be determined
NBFMCC	Incremental charge for DER Portal, DER Map, SCEF, and CT Residential Solar programs	N/A	To be determined

As shown in the table, OCC does not understand why Eversource recovers non-hardship uncollectible expenses through the NBFMCC rate component and UI does not. We request a clearer explanation of the types of expenses that are currently recovered within the NBFMCC from Eversouce and why they are considered to be non-hardship uncollectible expenses. Acknowledging that the ESI is unique to Eversource, it would also be helpful to review similar information regarding the ESI categorization of non-hardship uncollectible expenses. We also request a clear explanation of why UI does not incur these same types of non-hardship uncollectible expenses through the NBFMCC.

We have a written explanation of the cost recovery methodology for non-hardship uncollectible expenses for all rate components from Eversource and UI, and request workbooks illustrating these calculations for 2023 and 2024.

We plan to provide more detailed comments and recommendations after receiving Eversource and UI responses to these discovery requests.[26]

3. *Regarding the variable impact of Power Purchase Agreements (PPAs) and other public policy contracts on the net expenses of the NBFMCC, provide proposals to reduce the impact of wholesale energy market fluctuations on PPA contract costs paid by ratepayers.*

As the Authority and most stakeholders are aware, the July 1, 2024 NBFMCC adjustment was historically massive due primarily to an under-recovery from Calendar Year 2023 of $264,877,387. It is OCC's understanding that the majority of this under-recovery was due to Eversource's incurrence of $64,378,206 in net cost for the Millstone contract, while rates were set using the 2022 incurrence of ($232,421,119) net cost (i.e. credit).[27] While market conditions in 2022 were favorable, in that wholesale revenues greatly exceeded contract costs, the conditions reversed in 2023. We understand the focus of this question – and more broadly, a topic for this proceeding – is to discuss potential safeguards against similar scenarios that could impose significant rate shock in the future. As OCC noted in our April 3, 2024 letter in lieu of written exceptions in Docket No. 24-01-03, we welcome this proceeding and appreciate the opportunity to engage in this discussion.

Traditional ratemaking principles generally provide a strong foundation for addressing this issue. James Bonbright's *Principles of Public Utility Rates* (1961) famously sets forth eight ratemaking principles that are a common reference point for appropriately setting rates. A few of the principles are relevant to rate shock, but perhaps most on-point is Principle 5, "Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers." This idea is often referred to as the principle of "gradualism," which favors making small adjustments to rate structures over time, rather than large changes all at once.

One way to improve the gradualism of rate impacts for the NBFMCC would be to increase the frequency of rate adjustments. For example, if rates had been adjusted to account for the above-

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[26] OCC has drafted discovery to Eversource and UI and will supplement our comments with this information in a later round of comments.

[27] The background of the NBFMCC rate setting that resulted in this underrecovery is somewhat complex and it is our understanding that different stakeholders hold different views as to the specific causation of the mismatch between costs and revenues. OCC takes the view that it would be most productive to focus this proceeding on forward-looking solutions.

referenced Millstone cost over a monthly basis, the rate shock would surely have been substantially reduced. However, monthly rate adjustments could cause tension with another Bonbright principle – that rates should aspire to achieve and maintain "[t]he related, 'practical' attributes of simplicity, understandability, public acceptability, and feasibility of application." A rate that changes on a monthly basis would be difficult for consumers to budget for – or to understand – and would certainly impose increased administrative burden on the EDCs, the Authority, the OCC, and any other stakeholder involved in the business of administering rate adjustments. So, more frequent adjustments to the NBFMCC could certainly help to smooth rate shock, but the frequency should be manageable, understandable, and acceptable to ratepayers.

It could also make sense to consider aligning NBFMCC adjustments with other general adjustments to rates – such as the GSC adjustments in July. The Authority implemented that very idea last year, which certainly blunted the immediate total-bill impact of the overall RAM adjustment, but also resulted in accelerated recovery of the RAM revenue requirements, by spreading them across only nine months rather than the normal twelve-month period of a May 1st adjustment. We note that the GSC and NBFMCC naturally somewhat oppose one another – with many PPA costs within the NBFMCC being driven by low wholesale market pricing, and GSC costs being generally driven by high wholesale marker pricing, although the timing of market impacts on either rate does not necessarily align. It may be worth discussing whether the NBFMCC could be separated from other RAM accounts such that adjustments could better align with supply-related adjustments, without impacting the other components of the RAM. It may also be useful to confirm the timing of RAM adjustments. As one can expect future temperatures to increase and electrification will drive higher electric use in winter months, adjustments should continue to be timed to occur within the spring and fall months when electricity use is generally lower to make rate changes more manageable for customers.

Another relevant Bonbright principle is Number 3, "Effectiveness in yielding total revenue requirements". As discussed above with respect to the recent Millstone under-recovery, had revenues been set at the outset to more closely match costs, some rate shock could have been mitigated. NBFMCC, like other RAM components, is currently set for a future rate period using prior-year actual expenses as proxies, and allowing for known and measurable adjustments to those proxies, based upon expected changes in the future. Conceptually, when known and measurable adjustments fall short of actual incurred costs, the result is an under-recovery (and – all else equal – a consequent rate increase), and when they exceed actual incurred costs, the result is an over-recovery (and consequent rate decrease). In the longer term, ratepayers are harmed by under-recoveries because they must pay the unrecovered balance plus carrying costs – so the overall cost is higher than necessary. However, in the shorter term, ratepayers can also be harmed by over-recovery, in that – all else equal – monthly bills are set higher than necessary. Naturally, utilities are also harmed by under-recoveries in that they are deprived of immediate cash flow. Hence, the shared goal of all stakeholders should be accuracy – the best case scenario is for rates to be set no higher *and no lower* than necessary for the utility to recover its authorized revenue requirement.[28]

[28] To be abundantly clear, we are very intentionally referring to the authorized revenue requirement here – as a separate and distinct concept from a utility's *requested* revenue requirement.

To achieve accuracy, it could be helpful to provide for flexibility in the determination of expected future costs. While the known and measurable standard is a powerful risk prevention tool in setting base rates (where actual costs are never reconciled to authorized revenues, so ratepayers must always be protected from overestimated actual costs), in the case of PPAs or other volatile cost-drivers, there really *can't* be a "known" or "measurable" future cost – the best option is to use educated estimates. OCC would therefore support further conversations about the expected standards for future-looking adjustments to historic costs in setting reconciling rates. We would favor a system where utilities must provide any and all information relevant to potential future costs – including their own internal projections and the bases therefore – and where such information is used as the foundation for a discussion among stakeholders and the Authority to determine the most appropriate estimate. If estimates are consistently over- or under-recovering costs, the Authority and stakeholders should re-examine the estimates, identify the drivers of inaccuracy, and require adjustments to improve accuracy.

4. *Regarding the under- or over- collections for the NBFMCC or any other RAM rate component, comment on:*
    a. *What parameters, if any, can be used to determine when an under- or over-collection is substantial enough to create "rate shock" if incorporated into the NBFMCC or another relevant RAM rate.*

Rate shock is fundamentally an intangible concept for which it may be difficult to define precise parameters, but the concept is simple – there is some price point, relative to the current price, that is generally unacceptable to the consumer. For an extraordinarily inelastic good like electricity – for which there are no competitive alternate options – the consumer response to that price point is not necessarily expressed in diminished demand, but rather in economic distress and a lack of full payment of electricity bills which affects the EDC and all of its customers. Rate shock is not a reaction to a price in isolation, but to the magnitude between an initial price and a higher price and whether or not that change in price could be expected and reasonably planned for.

It is important to keep in mind that rate shock is driven by the total-bill impact, rather than any one portion of bills. In other words, a substantial increase to a particular bill element (e.g. the SBC) will not necessarily result in rate shock if there are mitigating offsetting drivers (e.g. decreases to other portions of the bill, such as the GSC).

Although the month-to-month change in cost, as compared to the expected month-to-month change in cost, is a primary rate shock driver, other metrics should be considered in defining parameters for rate shock. For example, the total annual impact in comparison to household income could provide insight into the capacity for a particular category of customers to absorb rate volatility. It would be useful to examine this metric for several types of customers, including the average low-income customer, the average non-low income customer, small commercial customers, and larger commercial customers.

We understand that income information can be challenging to attain and complex to analyze, and that simpler solutions may seem less administratively burdensome. For example, it may appear more efficient to define rate shock as simply a percentage increase to a total *average* bill, such as users of 700 kWh per month. However, we do not recommend this, as it would fail to account for the relative income factor as discussed above, and would also suffer from imprecision in measuring the actual impacts experienced by diverse categories of customers. Also as demonstrated in July of 2024, if a bill increase is implemented at a time when average usage is higher than normal, it may not be appropriate to apply an annualized average usage to defining parameters. Instead, we recommend defining rate shock in consideration of both actual total-bill impact; annual bill impact; and via thresholds established for low-income customers and non low-income customers and the threshold for low-income customers could be lower than for non low-income customers.

OCC looks forward to continuing the conversation about how best to define rate shock, in light of these considerations and those advanced by other stakeholders.

b. *Proposals for how substantial over- and under-collections should be handled, including whether stakeholders would recommend using a multi-year amortization period for the recovery of such over- and undercollections, and why or why not.*

As discussed above with respect to PPAs, the period of time over which a revenue requirement is recovered has a direct impact upon the monthly cost of recovery to a consumer. Generally, spreading the same revenue requirement over a longer recovery period will reduce the rate impact, and vice-versa. Of course, there are two substantial concerns with prolonged recovery models: the effect of carrying costs, and the potential for layered or "pancaking" recovery periods.

With respect to the carrying cost issue, when viewed through the broadest lens it may seem clear that consumers are generally "better off" where carrying costs are reduced or wholly eliminated. For example, if a consumer were seeking financial advice as to their choice to either finance a car over 15 years, 7 years, or to purchase the car outright, the seemingly obvious answer would be to pay cash – as this would be the lowest overall cost. If cash were not an option, the next best option might be a 7 year loan because, again, this would impose less overall interest cost than the 15 year loan. For these reasons, it may seem clear to some stakeholders that amortizing under-recoveries is never in the best interest of consumers.

But this view ignores the reality of the financial conditions of normal American households. Recent surveys suggest that more than half of Americans do not have enough savings to cover 3 months of expenses, and less than half reported that they could cover an unexpected expense of $1,000 with savings. Other reports suggest that approximately 25% of households live paycheck to paycheck, meaning they are unable to absorb any incremental household expense. In Connecticut, a Bridgeport resident with an annual income of $46,000 may not qualify for hardship protections and low-income programs (as their income would exceed the 60% SMI threshold of $45,505), but pays an average monthly housing cost of $1,850; an average monthly food cost of $575, monthly transportation cost of $424, average monthly healthcare coverage of $477, average monthly phone bill of $144; average monthly heating oil bill of $76; and average monthly clothing cost of $72. That leaves $215.33 to pay the average United Illuminating electric bill of approximately $260 (using 700 kWh/month).

So while any additional total cost due to carrying charges is not ideal, the reality is that Connecticut households are reaching a point where they simply have no more room in their monthly budgets to absorb extraordinary and unpredictable increases. OCC therefore continues to support the measured and conservative use of amortization or other financing solutions at lower borrowing costs in order to mitigate monthly pressures on household budgets.

However, in order to avoid the potential for "pancaking" multiple layers of amortizing costs, these financing solutions should be targeted to costs that are generally: 1) exogenous, meaning they are outside the normal course of a utility's annual operations; 2) material, meaning they are so large as to qualify for unusual rate treatment that imposes increased overall costs; and 3) unlikely to recur, meaning they are driven by specific circumstances that were unforeseeable and unlikely to regularly arise again. For example, it is OCC's opinion that Eversource's NBFMCC under-recovery in the 2023 calendar year fit these criteria – the cost was: 1) not central to the provision of distribution service, in that it was largely driven by legislatively mandated PPA contracts; 2) material, in that it was significantly higher than historical costs in the category and the under-recovery alone imposed an increase of over $10 per month for the average customer; and 3) unlikely to recur, because it was ultimately the result of market conditions driven by several historically anomalous factors.

As OCC has repeatedly advocated in the past, financing options other than traditional utility amortization should also be seriously considered for eligible costs. Securitization, state bonds, or other solutions could lower carrying costs while also providing utilities with faster recovery and greater certainty as to future cash flows. Again, we look forward to continued engagement in this discussion as the proceeding evolves.

OCC thanks the Authority for its consideration of these comments.

Respectfully submitted,

STATE OF CONNECTICUT
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cc: Service List