BEFORE THE

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY

Docket No. 24-10-04

APPLICATION OF THE UNITED ILLUMINATING COMPANY TO AMEND ITS RATE SCHEDULES

Prefiled Surrebuttal Testimony of

Caroline Palmer

On Behalf of

The Office of Consumer Counsel

March 24, 2025

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I. INTRODUCTION

Q Please state your name, title, and employer.

A My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Office of Consumer Counsel ("OCC").

Q Are you the same Caroline Palmer who submitted prefiled direct testimony in this docket?

A Yes.

Q Did you file rebuttal testimony in this docket?

A No.

Q What is the purpose of your surrebuttal testimony?

A I respond to The United Illuminating Company (UI or Company)'s rebuttal testimony regarding its cost of service study (COSS) and time-of-use (TOU) rate design and to the Connecticut Industrial Energy Consumers (CIEC)'s rebuttal testimony regarding UI's COSS. If I do not comment on a rebuttal topic, it should not be interpreted as agreement.

II. ALLOCATED COST OF SERVICE STUDY

Q What is the purpose of this section of your testimony?

A I respond to the Company's and CIEC's rebuttal regarding three of UI's COSS methods. I continue to recommend that the Authority direct the Company to discontinue the minimum system method and adopt the basic customer method for distribution cost classification. If the Authority approves any form of minimum system study, I continue

to recommend that UI adjust demand allocations to recognize that the minimum system also meets nearly all of certain customer classes' maximum demands. I also continue to recommend classifying AMI meters as customer, demand, and energy related and using UI's alternate demand allocators for informing revenue allocation.

UI Should Not Classify Distribution System Costs Using a Minimum System Study

Q Do UI and CIEC agree with your recommendation to classify FERC accounts 364-368 as 100% demand-related?

A No. Both UI and CIEC oppose my recommendation to use the basic customer method, which treats FERC accounts 364-368 as 100% demand-related and classifies only costs associated with services, meters, meter reading, and billing as customer-related. UI and CIEC dispute that the distribution infrastructure in the minimum system study should be treated as fully demand-related. Both also disagree with my recommendation that if PURA approves the use of a minimum system study, customers whose peak demands can be met with the minimum system should not pay demand costs for those accounts.

Q Why does UI dispute that the distribution infrastructure in the minimum system study is fully demand-related?

A UI states that "Increases or decreases in demand alone do not result in proportional increases or decreases in the number of poles and miles of conductors required to distribute electricity geographically."[1] I do not necessarily disagree with UI's claim, though the claim is unsubstantiated and overly absolute.

[1] Exhibit UI-RP-REBUTTAL-1 at 4-5.

Q What factor besides customer demand might contribute to the number of poles and miles of conductors?

A The costs and volume of infrastructure in FERC accounts 364-368 are primarily driven by the estimated demand to be served and the geographic dispersion of customers. Thus, any difference in the proportional increase or decrease that UI described can be best attributed to geography. Indeed, UI's rebuttal references the influence of geography numerous times. For example: "Distribution system costs are incurred to move electricity…to individual customers that are distributed geographically throughout the service territory."[2] And: the "number of poles and miles of conductors constituting the primary distribution system are driven by the geographic dispersion of the customers and the need to provide them access to the system."[3] The Company provides access to the system via customer-related infrastructure like service drops and meters, and the number of poles and miles of conductor between those access points is a function of geographic dispersion.

Q Provide an example of why geography influences distribution costs more than number of customers.

A The number of poles or miles of conductor and conduit required to serve a housing development is likely to vary more based on the distance of the development from other infrastructure, such as if the development is located within 0.1 versus 10 miles of the rest of the system, than based on whether there are 10 or 50 houses in the development.

[2] Exhibit UI-RP-REBUTTAL-1 at 4.
[3] Exhibit UI-RP-REBUTTAL-1 at 12.

Q Does the minimum system study account for geographic dispersion?

A No. The minimum system study categorizes costs as either related to demand or customer count. UI oversimplifies the study and its implications, stating that the "point of conducting a minimum system study is to isolate the portion of the distribution system that does not vary with demand." However, the study does not just claim to identify costs that don't vary with demand; it also isolates a portion of costs that purportedly vary based on number of customers. There is no measure of geographic dispersion in the study, and geography is not necessarily well-correlated with the number of customers. Therefore, the number of customers is not a very representative allocator.

Q Does industry literature consider customer count to be a good proxy for geographic dispersion?

A No. James Bonbright's widely recognized *Principles of Public Utility Rates* notes that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system."[4]

Q Given that geography is not an allocation factor, that customer count is not a good proxy for geography, and that the minimum system study overstates the costs classified as customer-related, is it reasonable to treat all of FERC accounts 364-368 as demand-related?

A Yes. I argued in direct testimony that the minimum system study overstates customer-related costs due to its capacity and its use of imprecise accounting data.[5] The Company did not dispute that the broad infrastructure categories used in the study include certain components that should be considered demand-related. The Company also did not dispute

[4] Bonbright, James. *Principles of Public Utility Rates.* 1961, p. 348. Produced in UI-OCC-10 Attachment 15.
[5] Palmer Prefiled Direct Testimony at 11-13.

that its minimum system meets some customer classes' maximum demands, which I discuss next. For all of these reasons, I continue to recommend the basic customer method.

Q Do UI and CIEC dispute your assessment that the Company's minimum system also meets customers' peak demands?

A No. Neither UI nor CIEC disputes my analysis[6] that all but a tiny fraction (less than 0.25%) of the residential peak demands are estimated to be within the Company's minimum system capacity and that the same is true for the vast majority of Rate GS customers' maximum demands (less than 2% of the non-demand Rate GS customers).

Q How did you recommend addressing the minimum system's load carrying capacity?

A I recommended that, for any FERC accounts classified using a minimum system study, the Company allocate no demand-related costs to the customer classes whose peak demands can generally be met through the identified "customer-related" portion of the system, which includes the residential and GS non-demand classes, and to reduce the Rate GS demand costs to reflect only the capacity above the minimum system level.[7]

Q Do UI and CIEC agree with your recommendation to exempt certain classes from demand-related costs if PURA approves the use of a minimum system study?

A No. First, UI and CIEC each misunderstand portions of my testimony on this topic. Second, both UI and CIEC attempt to dismiss my concern and recommended solution by arguing that I've misinterpreted the definition of minimum system. However, their arguments do not alleviate the need to address the load carrying capability of the Company's minimum system.

[6] Palmer Prefiled Direct Testimony at 11.
[7] Palmer Prefiled Direct Testimony at 16-17.

Q How does UI misunderstand your testimony on the minimum system's load carrying capability?

A UI described me as concerned with the choice of the minimum sized asset used in the studies.[8] However, I did not dispute UI's choice of the minimum sized asset. My testimony only expressed concern that the chosen minimum sized asset can meet certain customer classes' peak demand requirements.[9]

Q How does CIEC misunderstand your testimony on the minimum system's load carrying capability?

A CIEC states that I "conclude[] that because there is sufficient capacity in the extant system there is little justification for classifying costs in these accounts as customer-related."[10] However, I did not make the stated conclusion based on the load carrying capacity of the system. Rather, I noted that the Company's so-called "minimum system" nearly meets entire customer classes' peak demands. Because the so-called "minimum system" actually meets the maximum demand of entire classes of customers, it inflates the costs classified as customer-related, and is therefore unsound to use as the basis for determining customer-related costs.

Q Do UI and CIEC object to your characterization of the minimum system?

A Yes. They rebut my statement that "the method requires distinguishing a hypothetical system that serves only customers, not their electricity demand."[11] UI argues that the "concept of Minimum System assumes that there is a minimum sized distribution system

[8] Exhibit UI-RP-REBUTTAL-1 at 10.
[9] Palmer Prefiled Direct Testimony at 11-12.
[10] Chait Rebuttal Testimony at 6.
[11] Palmer Prefiled Direct Testimony at13.

required to be capable of serving the minimum requirements of customers."[12] Similarly, CIEC argues that "the NARUC Manual states that this method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer."[13]

Q Do you revise your statement that the minimum system must serve only customers, not their electricity demand?

A Yes. I revise my statement to: the method requires distinguishing a hypothetical system that serves customers' minimum demand requirements.

Q Does your revision change your argument or your recommendation?

A No. My undisputed assessment, described above, that the Company's minimum system nearly meets entire customer classes' peak demands makes clear that UI's minimum size distribution system serves far more than the "minimum loading requirements" of customers. UI states that "a minimum level of load-carrying capacity is acceptable under the Minimum System Study method"[14] but does not acknowledge or attempt to account for the fact that, for some customer classes, the *minimum* level of load-carrying capacity that UI has deemed acceptable is also just about the *maximum* level of load-carrying capacity needed for those classes. My recommendation accounts for this capacity, by allocating those classes no demand costs since they impose nearly no further demand cost on the system.

[12] Exhibit UI-RP-REBUTTAL-1 at 11.
[13] Chait Rebuttal Testimony at 4.
[14] Exhibit UI-RP-REBUTTAL-1 at 11.

Q How does UI rebut your recommendation to account for the load-carrying capacity of the minimum system?

A UI states that "virtually all customers impose some lowest common denominator amount of minimum load on the system, and so the minimum system costs should be treated as providing equal benefit to all customers on the relevant system."[15]

Q How do you respond?

A I don't dispute that all customers impose some minimum load on the system. UI has proposed to treat the cost of that load as customer-related. However, customers should not be charged twice for the same capacity: once through the "customer" portion of the minimum system, and then another time through the demand allocator. Indeed, the NARUC Cost Allocation Manual, which UI and CIEC cite heavily to justify the minimum system method, notes that "when using the minimum-size distribution method…the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[16] The customer classes whose maximum loads are almost entirely met by the minimum system have already paid their demand-related cost through the "customer-related" portion of the system and should not be charged again.

Q How does CIEC rebut your recommendation to account for the load-carrying capacity of the minimum system?

A CIEC attempts to argue that the examples I provided, of jurisdictions that do account for the load-carrying capacity of the minimum system, do not apply to UI or are unofficial.

[15] Exhibit UI-RP-REBUTTAL-1 at 11-12.
[16] National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual.* 1992 at 95. Produced in UI-OCC-10 Attachment 1.

For example, CIEC suggests that National Grid in New York only proposed to allocate $0 to the Residential, Residential Time of Use, and Small General Non-Demand classes for the demand-related portion of conductors and conduits, but that my proposal would also apply to poles, towers and line transformers.[17] However, National Grid did apply its proposal to poles and towers (FERC account 364), as can be observed in its COSS.[18]

Q Has the Ontario Energy Board ordered utilities to account for the peak load carrying capability of their minimum system?

A Yes. CIEC points out that I did not cite an Ontario Energy Board order adopting and implementing Staff's recommendation. I confirm that the OEB did enshrine a peak load carrying capability (PLCC) adjustment in its report "provid[ing] the cost allocation methodology directions approved by the Board."[19] The adjustment determines how much demand for a rate classification can be met by the minimum system and credits this amount against the classification's non-coincident peak demands used for determining demand allocators. The credit determining how much of the classification's demand is met by the minimum system is the product of the number of customers/connections and 0.4 kW per customer/connection. Ontario continues to use this method, as the OEB has since reaffirmed the original report dictating that electricity distributors use the

[17] Chait Rebuttal Testimony at 8 and 10.
[18] *See* Attachment CP-Surrebuttal-1. Schedule 8A Sheet 1 (p.203) shows that demand costs in FERC Accounts 634-367 are allocated using "NCP_Pri-PLCC" and "NCP_Sec-PLCC", which, per Schedule 8D Sheet 1 (p.222), allocate 0% of costs to the above-named customer classes.
[19] Ontario Energy Board. Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors. September 2006. At 53-55. https://www.oeb.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf. *See* Attachment CP-Surrebuttal-2.

methodology in a 2007 Board report,[20] which the OEB again referenced in its Filing Requirements For 2024 Electricity Distribution Rate Applications.[21]

Q What is CIEC's primary concern with your (and National Grid NY's) recommendation to assign zero demand costs to certain customer classes?

A CIEC states that a "minimum system capable of meeting the peak load for almost all customers [in a class] is not sufficient to serve the peak load of these classes" and thus, a non-zero share of the demand-related costs should be allocated to these classes.[22] CIEC claims that if my recommended approach were to be adopted for use in this rate proceeding, it would "under-allocate demand-related costs to customers" in the specified classes.

Q Are CIEC's concerns about under-allocating demand-related costs to customers unbalanced, considering the likelihood of over-allocating much greater costs to the same customers?

A Yes. CIEC is worried about the 0.04% of Rate R customers and 0.22% of Rate RT customers whose maximum demand requirements may exceed the minimum system equipment capacity. However, without my recommended exemption from demand costs, those customer classes – including the 99.96% of Rate R customers and 99.78% of Rate RT customers whose peak demand requirement does not exceed the minimum system capacity – will be held responsible for over 50% of the demand-related costs of the

[20] Ontario Energy Board. Application of Cost Allocation for Electricity Distributors - Report of the Board. November 2007. At 1. https://www.oeb.ca/documents/cases/EB-2007-0667/Report_Cost_Allocation_Review_20071128.pdf. *See* Attachment CP-Surrebuttal-3.

[21] Ontario Energy Board. Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications. Chapter 2 - Cost of Service. December 2022. At 44. https://www.oeb.ca/sites/default/files/OEB-Filing-Reqs-Chapter-2-2023-Clean-20221215.pdf. *See* Attachment CP-Surrebuttal-4.

[22] Chait Rebuttal Testimony at 9.

minimum system. The theoretical premise of the minimum system study should exempt these customers from the highly disproportionate demand costs that UI and CIEC would have them pay. Indeed, National Grid, a utility company with the same incentives as UI, came to the same conclusion and was willing to propose the same approach.

Q Do you heed CIEC's concern with your proposal to credit the GS demand class?

A Yes. I acknowledge that the minimum system would not be able to meet the peak load for all or almost all customers in the Rate GS demand class. CIEC is concerned that my recommendation to credit a portion of minimum load-carrying capacity applies only to the Rate GS demand class. I agree that at this time, a demand credit should only apply to classes for which the minimum system would be able to meet the peak load for all or almost all customers, i.e., the residential and GS non-demand classes. I would be open to considering a proposal from UI in the future in which every class receives credit for the amount of its demand met by the minimum system, similar to Ontario's approach.

UI Should Classify and Allocate Advanced Metering Infrastructure ("AMI") Meter Costs Based on Customer, Energy, and Demand

Q Does UI agree with your recommendation to classify and allocate AMI meter costs as customer, demand, and energy related?

A No. The Company claims that I conflated AMI meters with advanced metering infrastructure and states that the primary purpose of AMI or AMR meters is to measure consumption and demand. UI also notes that advanced metering infrastructure as a whole provides system benefits beyond just measuring consumption and the other components

of advanced metering infrastructure are classified as being both customer- and demand-related.[23]

Q Does UI's rebuttal contradict your direct testimony?

A No. My proposed AMI meter allocator conforms with UI's arguments as it, too, is largely customer-related, at 50%. UI's discussion of advanced metering infrastructure beyond metering is irrelevant to my testimony as I did not address those classifications.

UI Should Allocate Demand Costs Based on Class Contribution to Asset Peaks

Q Does UI agree with your recommendation to use its alternate demand allocators in its proposed ACOSS?

A No. UI rebuts my recommendation by relying on industry literature that is out-of-date for this topic and on arguments of continuity.

Q Does UI argue that NARUC recognizes the NCP allocator?

A Yes. UI argues that NCP is a recognized allocator for distribution demand costs in Connecticut and in the NARUC manual.[24] However, the NARUC manual was published in 1992, which predates the widespread use of AMI technology that enables the more granular alternate allocators that UI produced for this rate case. The fact that NARUC recognizes UI's proposed allocators is not a compelling argument because it could not have reasonably recognized allocators based on the contribution of each class to individual distribution equipment's peak. With widespread AMI technology now available and enabling allocator improvements, there is no need to stick to legacy methods just for the sake of their legacy.

[23] Exhibit UI-RP-REBUTTAL-1 at 13-15.
[24] Exhibit UI-RP-REBUTTAL-1 at 16.

Q Does UI also justify using legacy allocators because the legacy allocators used in the Company's ACOSS are very similar to the alternate demand allocators?

A Yes. UI even expressed surprise that I recommended the use of the alternate allocator despite the similarity of results. However, although the allocators are similar, they are not the same. Further, UI cannot know that they will not differ in the future. I continue to recommend that UI use its more granular alternate demand allocators in this case.

III. RATE DESIGN: TIME-OF-USE RATES

Q What is the purpose of this section of your testimony?

A I respond to the Company's rebuttal regarding its TOU proposals. I recommend customer education and evaluation of customer satisfaction with 11/1/25 TOU rates, in response to UI's continued commitment to a potentially very high on-peak rate. I also continue to recommend that UI or a third party develop a robust customer education plan for opt-out TOU rates based on input from stakeholders and customer surveys and that UI develop and implement a bill comparison tool. I continue to recommend considering other rates, such as critical peak pricing (CPP) for achieving substantial peak load reductions in addition to or as an alternative to opt-out TOU rates.

The Magnitude of UI's On-Peak Rates and On- to Off-Peak Price Differential is Excessive

Q Does UI share your concern that its 11/1/25 cost-based TOU rates are extreme?

A No. Despite acknowledging that the 11/1/25 price differential between on- and off-peak periods may seem high, the Company justifies its high summer peak residential rate as

providing an incentive for customers to shift their usage from peak to off-peak periods. The Company also notes that customers can always opt out of the 11/1/25 rate.[25]

Q Has the Company explained how it will inform and protect customers from such high on-peak 11/1/25 rates?

A No. Having the ability to opt out does not mean that customers will be unharmed by new, higher rates. The Company did not explain whether existing TOU customers will be automatically transitioned to higher rates, nor did it indicate any specific plan to inform customers of the potentially dramatic 11/1/25 rate change, if so. The only protection that the Company offered is to review bill impacts that accompany changes in non-distribution rates and to recommend mitigating any unacceptable impacts that become apparent through that review, such as limiting changes to ± 25% of the current rate.[26] The Company should propose a detailed customer education plan pertaining to 11/1/25 rate changes.

Q Is it clear that the rate will in fact provide an incentive for customers to shift their usage from peak to off-peak periods?

A No. If customers are deterred by the potentially extreme summer peak rates and abandon the rate or never sign up for it, it would not achieve the shifting that the Company envisions. UI should commit to evaluating the success of the rate, such as 1) through customers surveys about their satisfaction, especially exit surveys when a customer chooses to leave the rate, 2) bill comparisons to what customers would have paid on the standard flat rate, 3) load shifting analysis, where possible, and 4) tracking monthly enrollment to be filed in annual report. Further, UI could offer a second opt-in rate with

[25] Exhibit UI-RP-REBUTTAL-1 at 25.
[26] Exhibit UI-RP-1 at 46.

less aggressive pricing and could compare enrollment and surveys regarding customer satisfaction.

More Work is Needed to Develop a Plan for Transitioning to Opt-Out Rates

Q Does UI share your concern that more work is needed to develop a plan for transitioning to opt-out TOU rates?

A No. UI agrees that a customer education plan will be needed prior to the implementation of opt-out TOU rates but UI evidently considers the plans described in Exhibit UI-CSP-1, pages 34-36, to provide sufficient detail for the time being.[27] Exhibit UI-CSP-1 only includes notification of impending TOU rates and education on how to adjust behaviors to maximize benefits and how to opt-out. My direct testimony detailed additional preparation needed beyond the educational and promotional activities that UI identified in Exhibit UI-CSP-1, such as a bill comparison tool, but UI did not address this recommendation.[28] I continue to recommend that UI or a third party develop a robust plan based on input from stakeholders and customer surveys and that UI develop and implement a bill comparison tool.[29]

I accept UI's stated plan to move forward with outreach and tools once a timeline is determined for the opt-out TOU rates, but UI must commit to finalize and initiate the plan at least a year before the billing system modifications enable opt-out TOU rates. Customers must be educated and prepared for those TOU rates as soon as the technology can provide them.

[27] Exhibit UI-RP-REBUTTAL-1 at 27.
[28] Palmer Prefiled Direct Testimony at 49, footnote 96.
[29] Palmer Prefiled Direct Testimony at 49.

UI should investigate and implement opt-in alternative rates, particularly CPP

Q Does UI address your recommendation that PURA consider other rates for achieving substantial peak load reductions?

A Not directly; UI does not contemplate the merits of offering other rates in addition to or as an alternative to opt-out TOU rates. UI simply claims that I provided no support to show that CPP in particular will be a better alternative than TOU rates for UI, critiques the data that I did provide supporting CPP, and declares CPP rates to be more complex than TOU.[30]

Q Did you provide additional data after direct testimony showing that CPP could potentially provide similar, or even greater, load shifting results than opt-out TOU?

A Yes. I provided UI with additional data in response to the Company's interrogatory requesting documents and research to support that opt-out TOU rates provide only slight peak load reductions per participant compared to other opt-in tariffs, such as CPP. I compared the documented load reductions from four default TOU rates in Colorado, California, and Ontario to the load reductions from CPP shown in Table 4 of my testimony. The evidence reviewed suggests that default TOU rates typically result in peak load reductions of less than 4% and are likely to decline over time. In contrast, Brattle's Arcturus database indicates that peak load reductions from opt-in CPP are likely to fall in the range of 15% – 30%.[31]

Q Do you consider CPP rates to be more complex than TOU?

A No. CPP may be less predictable than a preset TOU rate, but it will only impact customers for a small portion of the year, unlike the Company's proposed End-State TOU

[30] Exhibit UI-RP-REBUTTAL-1 at 28.
[31] UI-OCC-33.

rate, under which six different prices will alternate on customer bills throughout the year, requiring customer awareness all year long.

IV. CONCLUSION

Q Does this conclude your surrebuttal testimony?

A Yes, it does.