Acadia Center
Advancing the Clean Energy Future
15 Court Square • Suite 1000
Boston, MA 02108

December 19, 2025

Massachusetts Department of Energy Resources
100 Cambridge St #1020,
Boston, MA 02114

<u>Acadia Center Comments on DOER's Ratemaking Straw Proposal as presented to the Electric Rate Task Force</u>

To Whom It May Concern:

Acadia Center is a nonprofit research and advocacy organization, committed to advancing the clean energy future in Massachusetts and across the northeast. Acadia Center tackles complex energy problems, identifies clear recommendations for reforms, and advocates to create significant change supportive of a low-carbon economy.

Acadia Center appreciates the significant effort that has gone into DOER's Straw Proposal (Proposal), as well as the opportunity to provide comments at this time, before the Proposal and accompanying Petition are sent to the Department of Public Utilities (DPU). The education and conversation provided by DOER's Electric Rate Task Force in anticipation of this Proposal was also decidedly beneficial in Acadia Center's developing its positions, and Acadia Center intends that the following feedback will be similarly beneficial to DOER. Acadia Center supports a number of the particular proposals DOER makes throughout its larger Proposal with some limited recommendations, while noting that some elements of the proposal have already been included into the DPU's recently initiated investigation in docket 25-200.[1] Acadia Center reserves judgement on some additional proposals until the issues can be more fleshed out in the eventual docketed proceedings.

Time of Use Rate Proposal

First, there is a clear and urgent need to plan, in preparation for the completed rollout of advanced metering infrastructure (AMI), for utility-specific time-of-use (TOU) rates that can be implemented as soon as possible to allow the affordability benefits of the AMI investment to flow to electric distribution company (EDC) customers.[2] Acadia Center's positions on particular rate design elements largely mirror the rate laid out in the Proposal.[3] The system and customer benefits of well-designed TOU rates have been borne out in research[4] and implementation

---

[1] Massachusetts Dep't of Pub. Utils., *Vote and Order Opening Inquiry*, D.P.U. 25-200 (Dec. 15, 2025).

[2] Mass. Dep't of Energy Resources, *Rate Task Force Ratemaking Straw Proposal* (Nov. 24, 2025), https://www.mass.gov/doc/rate-task-force-ratemaking-straw-proposal/download. Slide 9.

[3] Acadia Center provided comments on Time Varying Rates to the Interagency Rates Working Group that further detail specific positions on rate design, including support for a consolidated rate for supply, distribution and transmission, built-in flexibility and seasonality, automatic enrollment with opt-out optionality, a reasonably short on-peak period, and shadow billing. *See* Massachusetts Interagency Rates Working Group, *Long-Term Ratemaking Study and Recommendations* (Mar. 7, 2025), https://www.mass.gov/doc/irwg-long-term-ratemaking-study-public-comment/download at 3-5.

[4] Meredith Fowlie, Catherine Wolfram, C. Anna Spurlock, Annika Todd, Patrick Baylis & Peter Cappers, *Default Effects and Follow-On Behavior: Evidence from an Electricity Pricing Program*, NBER Working Paper No. 23553 (Jun. 2017), https://doi.org/10.3386/w23553.

info@acadiacenter.org • 617.742.0054 • acadiacenter.org
Rockport, ME • Boston, MA • Hartford, CT • New York, NY • Providence, RI

across the country.[5,6] And, while Acadia Center believes that the exact parameters of the TOU rates should be developed in a proceeding with appropriate interventions, the Proposal lays out a reasonable starting position. There is no element of the TOU rates as laid out in the Proposal that Acadia Center finds so objectionable as to request it be eliminated prior to an investigatory proceeding.

However, it would be helpful for DOER to provide or perform additional analysis specific to Massachusetts' EDC territories and customers to determine potential bill impacts, especially impacts to low- and moderate-income (LMI) customers. While both research[7] and practice[8,9] do indicate that LMI customers can benefit from TOU rates, the question of bill impacts is, to a certain extent, dependent on population and housing stock characteristics, rate design, and program salience.[10,11] Additional supportive data for the Massachusetts' context will be valuable in the upcoming proceeding.[12] To the extent that DOER envisions interactions between a new TOU regime and the income-eligible discount rates currently enacted or being enacted, Acadia Center also recommends spelling those out specifically in the Proposal, to ensure a shared understanding.

Acadia Center also warns that customer education and acceptance of TOU rates is critical for their success, and steps to empower customer understanding and demystify the change in rate structure should be significantly frontloaded before the rates are implemented to avoid backlash. Acadia Center strongly recommends shadow billing for all customers and bill stabilization for LMI customers for at least a year to facilitate the transition.

Massachusetts has competitive supply options, and Acadia Center believes AMI may be the missing piece to unlock a more vibrant competitive supply market or other innovative solutions. In addition to coordinating with

---

[5] Sanem Sergici et al., *PC44 Time of Use Pilots: End of Pilot Evaluation* (Oct. 4, 2021) (prepared for the Maryland Pub. Serv. Comm'n), available at https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf (showing bill savings outcomes).

[6] Jeff St. John, *Inside the Surprising Lessons from PECO's Time-of-Use Rate Pilot*, Utility Dive (Aug. 28, 2017), https://www.utilitydive.com/news/inside-the-surprising-lessons-from-pecos-time-of-use-rate-pilot/399629/.

[7] Folks, John & Karen Herter, *Assessing Equity: How Low-Income Customers Fare on TOU Rates*, 2020 ACEEE Summer Study on Energy Efficiency in Buildings (2021), https://opiniondynamics.com/wp-content/uploads/2021/06/2020_ACEEE-Summer-Study_Assessing-Equity-How-Low-Income-Customers-Fare-on-TOU_Rates_Folks.pdf

[8] David Littell and Joni Sliger (Regulatory Assistance Project), Time-Varying Rates in New England: Opportunities for Reform (2020). https://www.raponline.org/wp-content/uploads/2023/09/rap-littell-sliger-time-varying-rates-in-new-england-opportunities-for-reform-2020-october.pdf

[9] Stephen George and Eric Bell (Nexant), Default Time-of-Use Pricing Pilot Final Evaluation (November 1, 2019). https://www.calmac.org/publications/SCE_D-TOU_Pilot_Evaluation_-_Final_Report_-_Final.pdf

[10] Jenya Kahn-Lang et al., *A Meta-Analysis of Time-Based Electricity Rates* (Resources for the Future, Dec. 31, 2024) (finding high heterogeneity across rate designs and pilot characteristics in peak demand reductions under time-based pricing).

[11] Acadia Center, *New York's Household Energy Burden Imperative: Challenges and Solutions* (Mar. 10, 2025) (prepared for WE ACT 4 Change), available at https://weact4change.org/wp-content/uploads/2025/03/Acadia-Center-Energy-Burden-full-report-031025.pdf

[12] Though impacts of TOU rates have been modelled in a Massachusetts context, impacts to LMI customers are not examined. *See* Advanced Energy Economy, *Massachusetts Study on Time-Varying Rate Design to Enable Electrification* (2025), https://advancedenergyeconomy.sharepoint.com/sites/Marketing/Documents/2025/Reports/Massachusetts%20Study%20on%20Time-Varying%20Rate%20Design%20to%20Enable%20Electrification.pdf at 42.

municipal aggregators to unlock additional TVRs for supply,[13] Acadia Center also urges the DOER to recognize the role that 3rd party providers may play in a more competitive supply environment enabled by AMI and urge the EDCs to allow customers and 3rd party providers to access the data necessary for innovative competition. Given the history of 3rd party electric suppliers in Massachusetts,[14] customer protections in this area continue to be paramount.

Public Benefits Program Recovery as Fixed Charges

Acadia Center appreciates that there are arguments for[15] and against[16,17] the regressivity of higher fixed charges, often dependent on the relative energy use of high- and low-income households, and DOER, through its Proposal, and the DPU in its Vote and Order Opening Inquiry in docket 25-200[18] are attempting to parse these. The impact of a higher fixed charge would, presumably, be mitigated somewhat for LMI customers who are on discount rates; indeed, if the fixed charge were to be increased, it would become even more important to increase discount rate uptake. It is also noteworthy that a fixed charge of the magnitude that DOER recommends is out of line with the norm across the country, and there may be a more moderate increase that addresses the cost-reflectivity issue that DOER identifies.

The fundamental issue is that, depending on territory and customer characteristics, a fixed charge increase could be net beneficial or not, and until there is analysis of bill impacts in Massachusetts, with specific attention paid to LMI customers, Acadia Center reserves its support. As these questions are addressed through the 25-200 docket, Acadia Center anticipates continuing to weigh in.

Transitioning Reconciling Mechanisms into Base Distribution Rates

Acadia Center strongly supports eliminating reconciliation mechanisms wherever legally possible and transitioning the relevant costs back into base rates. The balance of risk has shifted definitively for EDC shareholders and against EDC customers, and a reduction or elimination of reconciling mechanisms would be a valuable start to rebalance that risk more appropriately for a rate-regulated industry. It appears that the DPU, in opening docket 25-200, has already indicated that they intend to examine, consolidate, or eliminate certain reconciliating mechanisms,[19] as the Proposal entails, and Acadia Center looks forward to participating in that docket.

---

[13] *Rate Task Force Ratemaking Straw Proposal*, slide 26

[14] Mass. Attorney General's Office, *A Predatory and Broken Market: the January 2025 Update Analysis of the Individual Residential Electric Supply Market in Massachusetts*, (Rev. May 2025). https://www.mass.gov/doc/2025-cs-update-rev-may-2025/download.

[15] Acadia Center, *Protect Consumers and Savings — Don't Raise Fixed Charges* (June 29, 2015), https://acadiacenter.org/protect-consumers-and-savings-dont-raise-fixed-charges/.

[16] Leah C. Stokes & David M. Konisky, *Understanding Fixed Charges in U.S. Utility Rates*, Resources for the Future Working Paper 21-35 (2021), https://media.rff.org/documents/WP_21-35.pdf.

[17] Next 10, *Designing Electricity Rates for an Equitable Energy Transition* (May 2024), https://www.next10.org/sites/default/files/2024-05/Next10-electricity-rates-v2.pdf

[18] MA DPU, *Vote and Order Opening Inquiry*, D.P.U. 25-200 (Dec. 15, 2025) at 13.

[19] *Ibid*, at 12-13.

Acadia Center also recommends that DOER include in its Proposal the subject of sharing mechanisms for the following purpose: any reconciling mechanisms that are unable to be eliminated be subject to a sharing mechanism, to be created in the next base rate case, that sets a baseline for spending and then exposes shareholders to the benefits and risks of under- or over-spending by sharing the benefits of good EDC management and the costs of bad EDC management with customers who have no alternative option.[20]

Recoupling

Acadia Center expresses cautious openness to recoupling as a mechanism to incentivize electrification and increase competition between EDCs and LDCs for heating customers, while ensuring that core principles for incentivizing energy efficiency are preserved/not unduly watered down. Particularly attractive is the potential for recoupling as a replacement for an attrition relief mechanism in the EDCs' multi-year rate plans.[21] In addition to reducing or eliminating reconciliation mechanisms, EDCs' needing to rely on their own sales and management to navigate increasing costs rather than being guaranteed an administratively forecast revenue requirement would derisk utility monopoly for customers, reduce costs and incentivize better management.

However, Acadia Center is concerned that recoupling may introduce a split incentive, giving EDCs a preference for electricity sales that harms the requirement to administer energy efficiency programs and DER interconnections, which would reduce energy sales. While this can be managed with close supervision, the EDCs have a tremendous informational advantage in any oversight process. As such, Acadia Center would recommend that, as a mitigation measure, DOER include in its Proposal support for examination of the potential advantages and drawbacks of a 3rd party energy efficiency program administrator model vs. the status quo. Additionally, Acadia Center would strongly encourage DOER to provide explanation of its intended goals for recoupling as well as analysis of the Massachusetts market that demonstrates 1) how its goals will be affirmatively reached by recoupling, 2) how recoupling may impact different customer segments' bills, and 3) what impacts would be of partial/targeted vs. full recoupling, as applicable.

Stay-Out Provisions

Stay-out provisions can be protective of ratepayers, depending on the overall framework of the performance-based ratemaking schema within which they operate. Rather than discontinuing stay-out provisions entirely, Acadia Center recommends consideration of optional stay-out provisions, which would be linked to any performance incentive mechanisms (PIMs) such that only an EDC that participates in a multi-year rate plan with a stay-out provision can receive rewards attached to PIMs.

Performance Incentive Mechanisms

---

[20] NRG, *High Power Bills Got You Down?* (Dec. 12, 2025), https://www.nrg.com/assets/documents/energy-policy/dlcc-briefing-high-power-bills-got-you-down-121225.pdf. Slide 10.

[21] *Rate Task Force Ratemaking Straw Proposal*, slide 36

Acadia Center supports the criteria DOER has outlined with regards to PIMs[22] but would add that Shared Savings Mechanisms can and should be considered for use more broadly than just for NWA projects, as previously mentioned. A non-exhaustive list of additional possible PIMs for investigation would be a grid efficiency PIM (measuring relative % utilization on- and off-peak, ideally targeted as granularly as possible), a peak load reduction PIM (setting a baseline peak load then providing a reward for decreasing it or penalty for increasing it, with a baseline that decreases over time), and shared savings mechanisms for otherwise required reconciliation mechanisms.

CapEx-OpEx Equalization Measures

Though TotEx is mentioned in the Proposal (slide 43), Acadia Center would strongly recommend that a more fulsome investigation of the process required to implement a TotEx regime be incorporated into the Proposal. Though TotEx may not be immediately ripe in Massachusetts, a forward-looking examination of the barriers and opportunities involved would be vital for any future application of TotEx and could save substantial time in a later proceeding to investigate actual implementation.

Conclusion

Acadia Center appreciates DOER's attention to these comments, as well as the continued emphasis on stakeholder engagement that has been evident throughout this process. These topics are complicated and carry great weight to the ratepayers of Massachusetts, and Acadia Center looks forward to continuing to engage with DOER on these critical ratemaking issues going forward.

Sincerely,

Noah Berman
Senior Policy Advocate and Utility Innovation Program Manager
Nberman@acadiacenter.org
617-742-0054 x107

---

[22] *Ibid*, slide 42

December 19, 2025

Via Electronic Mail Only
Massachusetts Department of Energy Resources
Attn: Austin Dawson
100 Cambridge Street, Suite 1020
Boston, MA 02144

RE: ELM Comments on Ratemaking Straw Proposal from Rate Task Force

Dear Austin,

Thank you for the opportunity to participate in the Rate Task Force discussion and process, and the opportunity to offer public comment on the recommendations offered in the November 24th Ratemaking Straw Proposal, on behalf of the Environmental League of Massachusetts ("ELM"). ELM also supports the Environmental NGO comments filed under separate cover today by Conservation Law Foundation and wishes to supplement them by going further into detail in certain areas.

As a threshold matter, ELM wishes to commend the Department of Energy Resources ("DOER") and you and your staff for your extraordinary efforts to create the Rate Task Force process and these recommendations. The discussions and presentations throughout this process have been invaluable in building a common understanding among advocates and stakeholders of these complex topics.

Recommendations ELM Supports

- Rate Design:
  - Default opt-out daily peak TOU for commercial and market rate residential
  - Cost reflective TOU rate design
  - Seasonality
  - Bill protections, marketing education and outreach, monitoring and evaluation, flexibility
- Regulatory Mechanisms
  - Transitioning or eliminating reconciling mechanisms
  - Ending revenue-cap formula
  - Regulatory sandbox
  - PIMs, especially replacing a portion of ROE
  - Proposed process and sequence

Suggestions for Adjustment to Recommendations

As set out in the recently released Grid Services Study, commissioned by MassCEC, one of the best ways to reduce the costs of distribution and transmission expenditures is to make better use of distributed energy resources (DER) as a provider of grid services. However, this requires location-specific mechanisms and valuations, integration of DER in utility planning, and dispatch signals that provide accurate and timely information and valuation. Given that time of use (TOU) rates can provide some, but not all, of these signals, ELM encourages DOER to consider the best ways to integrate planning and design of a comprehensive grid services valuation scheme in its requests for DPU proceedings.

Allow Location-Specific Daily Peak Hours

Rather than setting specific hours for TOU rates, it would likely be more effective for the DPU to establish principles regarding the minimum percentage of relevant annual, monthly, and daily peaks captured at key locations, and allow utilities to design the rates accordingly. This would have the dual outcome of requiring distribution utilities to capture better information regarding the drivers of localized peaks (thus establishing location specific valuation for grid services), and allowing different peaks in different utility territories, depending on relevant cost drivers. If consumers are well-informed regarding the relevant peak hours for their location, there should be little confusion created by having different peaks in different utility territories, or even within the same territory. As such, TOU peak hours do not need to be uniform across the state or across generation, distribution, and transmission rates (as laid out in the Straw Proposal).

Allowing the peak hours in TOU rates to vary across seasons and as system needs and cost drivers change will provide better matched financial incentives and outcomes for the grid. ELM believes that a five-hour peak period, as recommended in the Straw Proposal, be the upper limit for a non-critical, daily peak.

Evaluate DER Compensation and Access Across Programs

Creation of opt-out TOU rates provides an opportunity for the Commonwealth to evaluate its current demand management programs, appropriate price signals for bulk and locational grid services, and their interplay with rate structure. DOER and DPU should seek to mitigate potential inefficiencies created where different ratepayer-funded programs like SMART, Clean Peak, and Connected Solutions send differing signals and artificially drive compensation upwards. An optimized solution may involve lower payments through these programs, consolidation of programs, or reliance entirely on differentials between peak and off-peak hours. In tandem with evaluation of DER compensation and creation of locational values for distribution upgrades and their alternatives, the Commonwealth should use the opportunity that the rollout of AMI provides to evaluate ways in which DER can participate in offering grid services. Such an investigation should create pathways by which innovative solutions and new business models to aggregate flexible demand are allowed to participate directly, without having to go through constrained utility offerings like Connected Solutions.

Thank you for your consideration. Please do not hesitate to contact me at aboydrabin@environmentalleague.org with any questions.

Sincerely,

Amy Boyd Rabin

Amy Boyd Rabin
Vice President of Policy
Environmental League of Massachusetts

GREEN ENERGY CONSUMERS ALLIANCE

December 19, 2025

VIA ELECTRONIC MAIL ONLY
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

RE: Massachusetts Electric Rates Task Force Ratemaking Straw Proposal

To Whom It May Concern:

Green Energy Consumers Alliance is a local nonprofit organization working to harness the power of consumers and communities to speed a just transition to a zero-carbon world. We appreciated the Department of Energy Resources' (DOER's) November 24 presentation of its Ratemaking Straw Proposal to the Massachusetts Electric Rates Task Force. We thank DOER for its inclusive leadership in this arena and respectfully submit the following comments.

<u>Rate Design</u>

We largely agree with DOER's recommendations concerning rate design. In particular, we strongly support DOER's recommendation to pursue opt-out, whole-home time-of-use (TOU rates) via a single, consolidated peak period that includes supply, transmission, and distribution. We are convinced that TOU rates will result in short-term and long-term savings as long as those TOU rates are adjusted over time to promote efficiency (primarily through shifting demand from on-peak to off-peak periods), fairness, greenhouse gas reduction, and equity. We agree that a consolidated, 5-hour peak period appropriately balances system complexity with the need for clear, relatively simple price signal that consumers can understand. We also strongly support DOER's assertion that TOU rates must be extensively marketed to consumers and include protections for low-income residents and residents who have inflexible electricity needs to maintain their health and safety, such as shadow billing and the ability to easily opt out.

To take a step back, we believe that rate reform should:

a. Charge customers for power supply and delivery in proportion to how much they consume, when they consume it, and how much their electrification is contributing to reduced fossil fuel consumption. For reduced emissions, we specifically mean that rate reform should encourage the adoption of specific technologies that displace fossil fuels, namely electric vehicles, heat pumps, heat pump water heaters, induction stoves, and electric clothes dryers.
b. Fairly compensate customers for supplying power and other services to the grid.

Regarding DOER's rate design recommendations, we urge DOER to:

1. **Further study the potential impacts of shifting public benefits programs from volumetric charges to a monthly fixed charge.**

We understand DOER's motivation for considering moving public benefits programs' charges to a monthly fixed charge, as lower volumetric charges incentivize the electrification that is critical to the Commonwealth's climate goals. However, we believe this idea warrants further study before going to $40 per month, which would be one of the highest fixed charges in the country. A gradual increase would also have merit.

We would like to see how monthly fixed charges of different amounts (perhaps $10, $20, $30, and $40) impact on- and off-peak volumetric charges, and what the combined impact of those changes is in terms of:

- Bill impacts across different income strata;
- Bill impacts for customers with heat pumps and/or electric vehicles (EVs);
- Overall electricity consumption;
- Peak demand.

For example, a key question is: for low-income, low-usage households, would a higher fixed charge outweigh the potential bill savings of TOU rates? We believe such analyses are needed to determine the appropriate level of increase in the monthly fixed charge. Having said that, we lean towards supporting a beginning increase to $20 per month. That would allow for a proper evaluation with real-world data.

2. **Ensure that the on-to-off-peak ratio is sufficient enough to incentivize both load shifting *and* electrification.**

Ultimately, the rates for on- and off-peak electricity use should be determined by a cost-of-service study that is periodically reviewed. In other words, the rates should be determined by the actual differential in supply, distribution, and transmission costs in on- and off-peak periods. However, the open question of the appropriate size of the fixed charge introduces another variable into the equation. The final formula should result in an on- to off-peak ratio that is strong enough to incentivize the necessary load-shifting while also incentivizing the adoption of heat pumps and EVs, in particular, compared to their fossil fuel counterparts. If rates are such that they incentivize electrification but not load shifting, it may be worth layering critical peak pricing on top.

3. **Explain how the recommended rate design will interact with load management strategies being considered outside of the remit of the Rates Task Force.**

We understand that DOER's Load Management Study and this Rates Task Force work are separate. However, rate and load management programs *will* interact and warrant discussion in DOER's recommendations. We are particularly interested in understanding:

- How the potential existence of a geographically targeted load management program, like a ConnectedSolutions+, could or should impact the calculation for on- and off-peak pricing;
- How DOER recommends distinguishing what avoided marginal distribution costs should be attributed to TOU vs geographically-targeted load management programs.

4. **Model how TOU rates would impact heat pump users.**

Heat pump users in Massachusetts now have access to a heat-pump-specific seasonal electricity rate, which makes heat pumps financially feasible for many more households across the Commonwealth. We urge DOER to include in its analysis how a combination of TOU rates and increased fixed monthly charges would impact the economics of switching to a heat pump for customers heating with gas, oil, propane, or electric resistance heat. We are confident that TOU rates would support the adoption and off-peak charging of electric vehicles, but we would like to see more analysis regarding heat pumps.

Regulatory Mechanisms

Regarding the discussion of regulatory mechanisms, our primary comments relate to recoupling. We are open-minded to the topic but have not yet been convinced that the potential benefits of recoupling outweigh the potential drawbacks. As stated above, we place great emphasis on beneficial or strategic electrification, which essentially translates into EV, heat pumps, heat pump water heaters, induction stoves, and electric clothes dryers. Rate reform should focus on encouraging the adoption of those specific technologies, rather than just electricity consumption more broadly.

We urge DOER to open further discussions on this topic. The conversation around and roll-out of TOU and robust load management programs can occur separately from the conversation around recoupling. We urge DOER to move quickly on the former but not rush the latter.

Process & Implementation

Overall, we urge implementation of TOU rates as quickly as possible and appreciate the timeline laid out by DOER. However, in the short-term, we urge DOER to convene a stakeholder session with communities with municipal aggregation programs. It would behoove the Commonwealth to determine sooner rather than later what the appetite is among aggregation communities to develop tailored TOU offerings and develop a plan for coordination.

Thank you again for this opportunity to provide written comments.

Sincerely,

Larry F Chretien

Larry Chretien
Executive Director

December 19, 2025

VIA ELECTRONIC MAIL ONLY
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

Subject: Comments on the *Ratemaking Straw Proposal* (November 24, 2025) presented to the Massachusetts Electric Rate Task Force

To Whom It May Concern:

In accordance with the Massachusetts Department of Energy Resources' ("DOER") invitation to submit written comments on DOER's Ratemaking Straw Proposal ("Straw Proposal") presented to the Massachusetts Electric Rate Task Force ("Task Force"), the undersigned organizations respectfully submit the enclosed comments for your consideration. We thank you for your commitment to an affordable, equitable, and decarbonized energy future and for providing the opportunity to share feedback on the Straw Proposal.

The undersigned appreciate the leadership of DOER in forming the Task Force and in fostering inclusive dialogue on complex rate design and regulatory issues. DOER and the Task Force's commitment to creating a strong foundation for durable regulatory reform is a vital step toward a cleaner and more resilient energy future for the Commonwealth. In this vein, our comments provide feedback on DOER's proposals regarding (1) time-of-use ("TOU") rates; (2) a fixed policy charge; and (3) regulatory mechanisms.

Time-of-Use Rates

We generally support DOER's overarching goal of advancing time-varying rates to provide customers with greater control over their energy costs while also promoting energy affordability in Massachusetts. More specifically, we support DOER's proposal for the Massachusetts Department of Public Utilities ("DPU") to investigate TOU rates and require implementation through the electric distribution companies' ("EDCs") next rate cases, assuming the investigation demonstrates that time-varied rates can achieve desired outcomes.[1] We also support the DPU's exploration of DOER's recommendation for a single, consolidated TOU peak period to maximize beneficial load-shifting behavior (across supply, distribution, and transmission rate components) but look forward to developing the record on other design options in a DPU proceeding. Certainly, TOU rates can be an important tool for managing peak load growth and reducing the need for a costly electric system buildout. For example, TOU rates that encourage shifting electric vehicle charging to off-peak hours can provide significant benefits for all ratepayers.

[1] On December 15, 2025, the DPU issued an Order indicating it will soon open an investigation into electric rate design and regulatory mechanisms in response to DOER's forthcoming petition. Vote and Order Opening Inquiry at 23, D.P.U. 25-200 (Dec. 15, 2025).

However, TOU rate design and implementation must be approached carefully to ensure that (1) the rate does not disproportionately impact customers with high energy burdens; and (2) the rate provides customers who can afford to shift their load the opportunity and motivation to respond to price signals. Protections must be put in place for customers, especially vulnerable[2] customers with both "inflexible" loads critical to their health and safety (e.g., space heating and cooling) and "essential" loads supporting life-preserving medical appliances[3] (e.g., oxygen supply, dialysis machines). Finally, even with protections in place for these vulnerable customers, targeted outreach is needed to ensure they have access to energy-efficiency investments that reduce costs and strengthen resilience.

To that end, while we appreciate DOER's recognition of energy affordability for low-income customers as a primary stakeholder concern, DOER's proposals regarding TOU rates should go further to protect low- and moderate-income ("LMI") customers. We acknowledge the potential benefits of TOU rates for many customers,[4] but additional data and analysis specific to Massachusetts (or comparable conditions) to ensure that LMI customers are not harmed is necessary prior to any broad implementation of TOU rates. We primarily seek analysis of potential bill impacts for a variety of LMI household types in Massachusetts. We urge DOER and the DPU to work collaboratively and quickly to address this need for further analysis, which should then inform decisions about the treatment of customers enrolled in income-eligible discount rates and the need for hold-harmless protections.

Additionally, we urge DOER to update its recommendation regarding a bill stabilization program for low-income customers. DOER currently proposes that the EDCs study the impacts of bill stabilization on customers in other rate classes, citing a concern that such a program could increase bills for those customers, thereby reducing the effectiveness of TOU rates.[5] We recommend that the study also evaluate the extent to which bill stabilization would protect low-income customers from price spikes. We emphasize that successful time-varied rates must be equitable and protect low-income customers from bill spikes, especially in the first year following rollout. Moreover, if most low-income customers in the Commonwealth would see cost savings under a TOU rate—as the Straw Proposal suggests by citing to pilots that have

---

[2] These customers include, but are not limited to, older adults (aged 60 years and above), households with children under the age of 6, people with disabilities, households with persons with medical conditions (including chronic conditions), people without air conditioning, and pregnant people. *See* Centers for Disease Control and Prevention, *People at Increased Risk for Heat-Related Illness* (Feb. 20, 2024), available at https://www.cdc.gov/extreme-heat/risk-factors/?CDC_AAref_Val=https://www.cdc.gov/disasters/extremeheat/specificgroups.html; National Consumer Law Center, *Protecting Access to Essential Utility Service During Extreme Heat and Climate Change* at 21 (July 2024), available at https://www.nclc.org/wp-content/uploads/2024/07/202407_Report_Protecting-Access-to-Essential-Utility-Service-in-the-Time-of-Extreme-Heat-and-Climate-Change.pdf.

[3] Massachusetts households that use durable medical equipment such as a CPAP, nebulizer, mobility scooter, hospital bed, or enteral feeding pump are wholly dependent on electricity. *See* Sanya Carley, Shreya Bansal, Charles Harak, et al., *The Electricity Cost Burden of Durable Medical Equipment in the United States*, Scientific Reports (Dec. 28, 2024), available at https://pmc.ncbi.nlm.nih.gov/articles/PMC11682084/ (people who rely on durable medical equipment are more likely to be energy insecure with higher energy burdens than those who do not).

[4] Massachusetts Dep't of Energy Resources, Ratemaking Straw Proposal at 22 (Nov. 24, 2025), available at https://www.mass.gov/doc/rate-task-force-ratemaking-straw-proposal/download ("Straw Proposal").

[5] *Id*. at 24.

found the same in other parts of the country[6]—we are skeptical that bill stabilization would undermine the purpose of time-varied rates in a meaningful way.

We also seek additional analysis of the interactions between a TOU rate and seasonal heat pump rates. DOER has recognized that heat pump rates are a necessary tool to incentivize widespread heat pump adoption in the near term, but that they are a temporary solution until peak electricity demand shifts to winter.[7] With the convergence of TOU rates and the electric system becoming winter-peaking, heat pump rate customers may see significantly higher winter heating costs. To protect these customers, the Commonwealth must plan proactively for this transition. In its petition to the DPU, DOER should (1) include some discussion of potential strategies to avoid bill shocks for heat pump customers and (2) request that the DPU include the topic as one for further study and discussion in an investigation.

There are several components of DOER's TOU rate proposal that we support. This includes the recommendation to implement a TOU rate in phases[8] and to implement shadow billing, both of which are important safeguards for LMI customers. We also support DOER's recommendation that the EDCs be required to utilize advanced metering infrastructure ("AMI") data to protect customers (e.g., to monitor energy-limiting behaviors). In its final proposal to the DPU, we request that DOER provide a definition for shadow billing,[9] emphasize the importance of AMI data analysis for purposes of customer protection,[10] and recommend a stakeholder-vetted and DPU-approved marketing, education, and outreach plan[11] is in place well in advance of TOU rate implementation to minimize customer disruption. Rollout and education should be accompanied by recommendations for management devices, software, and other automation capabilities to make it easier for customers to adjust usage.

<u>Fixed Policy Charge</u>

We have concerns about DOER's proposal to introduce a fixed policy charge, especially in the context of potentially discontinuing revenue decoupling. While a fixed policy charge offers certain benefits–such as lowering bills for some customers and encouraging the adoption of electric vehicles, heat pumps, heat pump water heaters, electric clothes dryers, and induction stoves through reducing the volumetric charge–it risks placing disproportionate burdens on LMI customers with below average loads (particularly if protections like tiered discounts or income-based fixed charges are not in place). We urge DOER to clarify how it envisions tiered discounts interacting with a fixed policy charge[12] and encourage DOER to recommend DPU consideration of an income-graduated structure if the fixed policy charge proposal moves forward. A fixed policy charge also undermines incentives for reducing energy use through energy efficiency and conservation measures and discourages customers from installing solar or battery storage.

---

[6] *Id*. at 23.
[7] Petition of Massachusetts Department of Energy Resources for Requesting the Department of Public Utilities Open an Investigation into a Seasonal Heat Pump Rate, D.P.U. 25-08, at 4.
[8] Straw Proposal, at 21.
[9] *Id*. at 24.
[10] *Id*. at 25.
[11] *Id*. at 27.
[12] This clarification should address both existing tiered discounts (National Grid) and structures under DPU consideration in D.P.U. 24-15.

Finally, if public benefit fees serve as the basis for a fixed policy charge, such as that proposed by DOER, it will likely solicit criticism, especially given the recent attacks on the energy efficiency surcharge. As such, the issue of a fixed policy charge warrants further consideration within a DPU proceeding, where bill impacts can be examined. The DPU recently indicated it will explore the topic in D.P.U. 25-200, Investigation by the Department of Public Utilities on Its Own Motion into Gas and Electric Delivery Charges and Bill Redesign.[13]

Regulatory Mechanisms

While the Straw Proposal recommends several regulatory mechanisms worth considering for Massachusetts,[14] the undersigned organizations seek additional information and analysis before DOER advances these recommendations to the DPU. In the alternative, we urge DOER to include the requested information and analysis in its final proposal to the DPU.

As an initial matter, we request that DOER provide additional analysis to support its recommendations to discontinue revenue-cap formulas and stay-out periods associated with performance-based ratemaking ("PBR"), discontinue revenue decoupling, and require a future test-year approach to setting base distribution rates. The Straw Proposal identifies problems with the current portfolio of reconciling mechanisms and other attrition relief mechanisms (e.g., revenue-cap formulas). It argues that replacing this framework with "recoupling" and a future test year approach will improve cost transparency and accountability, shift risk back to the EDCs, and better incentivize the EDCs to promote electrification strategies and drive load growth.[15]

We agree that the current PBR framework and large volume of capital cost recovery mechanisms in Massachusetts have not served ratepayers and that comprehensive reform is needed. The need for a holistic review of capital cost recovery mechanisms is particularly urgent, and we are encouraged that the DPU intends to review reconciling mechanisms in the D.P.U. 25-200 proceeding.[16] However, the undersigned seek clearer identification of DOER's objectives and grounding principles, paired with robust analysis of how the proposed regulatory mechanisms would achieve those objectives and what trade-offs the Straw Proposal requires. As part of this analysis, we seek data showing how elements of PBR in the Commonwealth have or have not succeeded in achieving the goals they were designed to meet. Additionally, we recommend that DOER propose criteria that the DPU should use to assess the effectiveness of the proposed regulatory approaches, if adopted. Given the trade-offs between energy efficiency

[13] Vote and Order Opening Inquiry at 13-14, D.P.U. 25-200 (Dec. 15, 2025). While outside the scope of the Task Force, we also recommend that the state explore alternative financing pathways for critical energy efficiency programs, to ensure that funding mechanisms are less regressive than fixed charges on customer bills.
[14] The Straw Proposal recommends discontinuing revenue-cap formulas and stay-out periods; eliminating or transitioning capital cost recovery mechanisms into base distribution rates; discontinuing revenue decoupling; requiring a future test-year approach for setting base distribution rates; requiring the EDCs to use a marginal cost of service study; and establishing performance incentive mechanisms for load management and non-wires alternatives. These comments do not endorse any particular regulatory mechanism proposal, but rather, request additional information and analysis as a threshold step.
[15] Straw Proposal, at 33, 36, 38-41.
[16] Vote and Order Opening Inquiry at 11-14, D.P.U. 25-200 (Dec. 15, 2025).

and electrification under the mechanisms recommended in the Straw Proposal,[17] providing the DPU and interested stakeholders with a more robust analysis upfront will help ensure a more productive and properly scoped investigation into the regulatory framework.

Second, we recommend that DOER contextualize the Straw Proposal within the numerous efforts that the DPU is currently pursuing. Proceedings like the Energy Burden investigation (D.P.U. 24-15), the Climate Compliance Plan dockets (D.P.U. 25-40 through 25-45), the Heat Pump Rate investigation (D.P.U. 25-08), the Electric Sector Modernization Plans, and the Gas System Enhancement Plan ("GSEP") dockets all have potentially significant implications for the system DOER is trying to plan for through its Straw Proposal recommendations. It is critical to evaluate how these regulatory pieces intersect and fit together to ensure that they are not working at cross-purposes.

Finally, we emphasize our support for DOER's recommendation that the DPU explore broader CapEx-OpEx equalization mechanisms, such as Totex ratemaking. Totex represents a promising pathway for eliminating capital bias and has been successfully implemented in the UK and Italy. Under this approach, utilities manage combined budgets for all expenditures, divided proportionally at the CapEx/OpEx ratio into funds that can earn a return and funds that cannot earn a return. This rationalization of the budget removes artificial distinctions driving overinvestment in infrastructure. Alhough Totex has not yet been implemented in the United States, the potential benefits of Totex could be substantial, if a DPU investigation can identify an appropriate implementation process. The DPU should take steps to learn more about potential benefits for Massachusetts and what an appropriate implementation process might look like. We also support further exploration of a regulatory sandbox approach to test innovative products and services (e.g., Connecticut's Innovative Energy Solutions Program) and scale solutions for the grid and customers.

Process

We urge DOER to include in its petition to the DPU a request that any electric ratemaking investigation is not utility-led. To ensure a fair, transparent, and holistic proceeding, it is imperative that the scope and direction of an investigation are not determined solely based on plans and policy ideas proposed by the EDCs. The DPU should treat the utilities as any other stakeholder.

We also recommend that DOER request each of the following types of opportunities for stakeholder participation in an electric ratemaking investigation:

- Written comment opportunities with prompting questions from the DPU;
- Listening sessions with public comment; and
- Technical conferences (e.g., similar to the technical conferences held in D.P.U. 24-15).

[17] For example, DOER argues that discontinuing revenue decoupling will promote electrification by motivating the EDCs to offer additional customer incentives to electrify without contemporaneous recovery from customers. Straw Proposal at 39, 40. However, ending decoupling would also strengthen the EDCs' disincentive to support energy efficiency and distributed generation programs (because those programs would result in lower profits from lost revenues due to lost sales). *See* Massachusetts Electric Rate Task Force, Decoupling & Capital Recovery Expert Presentations: Presentation by Tim Woolf at 6 (Oct. 22, 2025), available at https://www.mass.gov/doc/topic-4-decoupling-and-capital-recovery-expert-presentations/download.

Conclusion

We thank DOER for its dedication to providing learning opportunities for stakeholders and laying a foundation for the DPU to investigate electric rate design and regulatory approaches. This work is a critical step toward improving affordability for all ratepayers and advancing the Commonwealth's decarbonization mandate.

As discussed above, we support a DPU inquiry into time-varied rates. However, we encourage DOER to improve upon its TOU rate proposal—including by providing additional analysis—to ensure vulnerable customers would receive adequate protections. With respect to DOER's recommendation for a fixed policy charge, we raise concerns and call for further study of this option to better understand actual impacts. Finally, we seek deeper analysis of the proposed regulatory mechanisms to inform potentially very costly regulatory decisions. In all aspects of electric rate reform, affordability and greenhouse gas emission reductions should be central goals. We look forward to continuing to engage on these important issues with DOER, the DPU, and other stakeholders.

Very truly yours,

Jocelyn Lee, Conservation Law Foundation
Katherine Lee Goyette, Conservation Law Foundation
Jerrold Oppenheim, Esq., The Low-Income Weatherization and Fuel Assistance Program Network, the Low-Income Energy Affordability Network (LEAN), and the Massachusetts Energy Directors Association (MEDA)
Mary Wambui, Planning Office for Urban Affairs
Noah Berman, Acadia Center
Larry Chretien, Green Energy Consumers Alliance
Philip Q. Hanser, Newton Energy Commission
Lindsay Griffin, Vote Solar
Sarah Krame, Sierra Club
Amy Boyd Rabin, Environmental League of Massachusetts
Jolette Westbrook, Environmental Defense Fund
Mark Kresowik, American Council for an Energy-Efficient Economy
Amanda Sachs, Rewiring America

December 19, 2025

Via email to austin.dawson@mass.gov

Austin Dawson
Deputy Director - Policy, Planning, and Analysis Division
Massachusetts Department of Energy Resources
100 Cambridge Street, 9th Floor, Boston, MA 02114

Re: Electric Distribution Companies Comments on Department of Energy Resources ("DOER") Ratemaking Straw Proposal

Dear Mr. Dawson,

Eversource, National Grid (Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid), and Unitil (Electric Distribution Companies, "EDCs") appreciate the opportunity to comment on the recommendations put forth in DOER's Ratemaking Straw Proposal ("Straw Proposal") presented to the Massachusetts Ratemaking Task Force ("Task Force") on November 24, 2025. The EDCs thank DOER for convening the Task Force and facilitating informed and forward-looking dialogue on electric rate design and regulatory mechanisms that advance Massachusetts' decarbonization and affordability goals.

The EDCs commend DOER in its efforts to bring together stakeholders to build understanding of regulatory issues facing Massachusetts at this critical point of the energy transition.

With the following comments, the EDCs seek to advance the Task Force's objectives of building a shared understanding, surfacing priority and outstanding questions, and preparing a strong foundation to be referenced in the Department of Public Utilities ("DPU") investigation into electric rates and ratemaking frameworks recently opened in Docket No. D.P.U. 25-200. DOER requests comments on 27 issues included in the Straw Proposal, falling under the broad categories of rate design, regulatory mechanisms, and process and implementation. Given the considerable scope of the Straw Proposal, the EDC comments will address overarching and priority issues to best serve the Task Force objectives. Omission of any issue in these comments does not necessarily indicate agreement with the Straw Proposal's recommendations.

The EDCs agree with the Straw Proposal with respect to the need for thoughtful investigations into rate design, but caution that the specific recommendations contained within the Straw Proposal do not reflect consensus positions, given the broad informational nature of the Task Force. Likewise, the Straw Proposal's recommendations on ratemaking frameworks represent fundamental changes in utility cost recovery and ratemaking approaches for Massachusetts and are not based on an evidentiary record that would be necessary prior to implementing such changes.

The EDCs' comments below address 1) regulatory mechanism recommendations; 2) rate design recommendations; and 3) recommendations for proceedings.

1. Regulatory Mechanism Recommendations

The Straw Proposal recommends several adjustments to existing regulatory mechanisms, many of which represent a significant shift in the cost recovery frameworks in place at each of the EDCs based on the record evidence presented in the dockets that established them. The recommendations include:

- Transitioning several reconciling mechanisms into base distribution rates or otherwise eliminating tariffs;
- Reviewing and updating marginal cost study guidelines and reinstituting filing requirements for future rate cases;
- Discontinuing revenue-cap formulas and stay-out provisions;
- Implementing a future test year in lieu of existing attrition relief mechanisms;
- Discontinuing revenue decoupling;
- Eliminating overdependence on capital cost recovery mechanisms following recoupling;
- Designing and implementing a load management performance mechanism to incentivize EDCs to drive efficiency and affordability; and
- Exploring further emerging ratemaking approaches such as a "regulatory sandbox" and Capex-Opex equalization mechanisms.

Several, if not all, of these proposed reforms would imply fundamental shifts in utility cost recovery and ratemaking approaches for Massachusetts, all of which have been established based on record-evidence balancing the interest of customers and the EDCs. As such, implementing any of these recommendations would require a full investigation of the trade-offs and consequences of doing so.

The EDC's comments on the Straw Proposal's regulatory mechanism recommendations focus primarily on three fundamental changes: 1) transitioning most reconciling mechanisms into base rates or eliminating them entirely; 2) discontinuation of revenue caps and stay-out provisions and replacement with a future test year; and 3) discontinuing revenue decoupling and transitioning capital recovery into base rates. We also provide some additional comments on other Straw Proposal elements.

As described during the Task Force, the EDCs are anticipating unprecedented system investment needs, driven by aging infrastructure, capacity needs, and decarbonization objectives, while also navigating an environment of upward cost pressures and the need to balance customer affordability, and ensure safe and reliable electric service that is critical to the Commonwealth's economy.

These investment needs must be supported by sound ratemaking frameworks. Fundamentally, ratemaking frameworks need to be able to adequately support the costs of the investments necessary to maintain safe and reliable energy service and support the programs needed to enable the Commonwealth's economic development and energy policy goals, while balancing customer interests and adhering to traditional ratemaking priorities. Adequate and timely cost recovery supports an EDC's credit quality and its ability to attract capital at a reasonable rate, which is critical to an EDC's ability to make ongoing necessary system investments at affordable rates, particularly in light of the substantial increase in required EDC capital expenditures foreseeable in the near future. For the reasons described below, the regulatory mechanism recommendations included in the Straw Proposal may fail to achieve these objectives. Investigation and analysis considering customer, EDC, and broader system and economic impacts would be necessary before a determination could be made to advance such reforms.

Transition of most reconciling mechanisms to base rates

DOER recommends transitioning several reconciling mechanisms into base distribution rates, stating that reconciling mechanisms:

- "Reduce cost efficiency incentive for EDC
- Shift risk from EDCs to ratepayer
- Erode regulatory lag
- Silo cost recovery and planning".[1]

DOER further recommends retaining reconciling mechanisms for transmission, supply service of last resort, extraordinary cost categories, or clean energy and public benefits programs.[2]

DOER's proposal to transition most reconciling mechanisms to base rates or otherwise eliminate them risks compromising the sufficiency of revenue support and could have the impact of compromising investment in support of the Commonwealth's economic and

[1] Straw Proposal, 31.

[2] Id.

energy policy objectives or result in more frequent rate cases.[3] Although DOER references customer detriment associated with reconciling mechanisms (e.g., reducing cost efficiency incentive for EDCs, shifting risks from the EDC to its ratepayers, etc.), the Straw Proposal fails to acknowledge the flip side of that coin that each of these mechanisms exist for good reason and could just as likely serve as a customer protection against establishing rates that are higher than necessary to collect the costs of the underlying program, or that, in the absence of such a mechanism, the EDCs would be required to file a base distribution rate case in which its rates are updated to reflect adjustments to *all* of its costs, rather than only adjusting to track with the costs of the underlying program; no more and no less.

As the EDCs noted in their Joint Reply Comments addressing long-term cost recovery in the ESMP, base distribution rates are not sufficient to fund the level of investment needed to support electrification and interconnection of distributed generation, as well as the other policy-related costs that expand business-as-usual operations.[4] The Department has recognized the insufficiency of a base-rate cycle to fund increasing investment level.[5] Removal of reconciling mechanisms without assurance of the availability of sufficient revenue will likely lead to the delay of policy-enabling investments, as EDCs will need to prioritize spending on investments that support safety and reliability.

While the Straw Proposal suggests that recoupling could support such revenue sufficiency, as described below, the EDCs are not aware of any evidence to support this assertion. The expected increase in capital expenditure requirements associated with existing programs (such as AMI, Grid Modernization, ESMP, and others) and anticipated investments necessary to support the Commonwealth's clean energy transition are above and beyond historical investment levels that cannot be assumed at this time to be covered by sales volume increases that will inevitably (and necessarily) materialize *only after* the capital is expended in order to enable the transition. Further, the Straw Proposal's assertion that removal of reconciling mechanisms would increase cost discipline and restore regulatory lag reflects a misunderstanding of the role of prudency review. The requirement that the Companies demonstrate the prudency of investments before recovering costs encourages the Companies to control costs and manage their projects regardless of when that prudency review occurs. Finally, it is worth noting that capex/opex alternatives will require

---

[3] The Companies note that most reconciling mechanisms are either statutorily created (see, e.g., G.L. c. 25, § 19, 21) or designed to recover costs to support public policy programs such as net metering, SMART, or electric vehicle charging. Some of these reconciling mechanisms support programs that are not within the Companies' control, e.g., SMART.

[4] D.P.U. 24-10, "Joint Reply Comments of EDCs in Approval of Electric Sector Modernization Plan," November 26, 2025, 3.

[5] Id, 4.

reconciling mechanisms to support cost recovery for such solutions if they are not already reflected in the test year and, in addition, may introduce accounting and ratemaking ramifications that are not considered in the Straw Proposal.

Discontinuation of revenue caps and stay-out provision and replacement with a future test year

The Straw Proposal recommends discontinuing revenue-cap formulas and stay-out provisions following the elimination of revenue decoupling. This recommendation does not recognize the value that has been created by the EDC's performance-based ratemaking ("PBR") plans. As explained by the EDCs in presentations to the Task Force on October 22, 2025, under PBR, customers benefit from greater rate stability and increased cost control incentives by leveraging base-rate stay-outs to motivate the EDCs to achieve cost-efficiencies during the rate plan. Studies have found that utilities that operate under PBR plans experienced slower rate escalation than comparable utilities.[6] In Massachusetts, PBR has allowed the EDCs to commit to not filing rate cases for extended periods of time and has minimized rate shock driven by changes in distribution rates that accompany base rate cases, especially base rate cases that occur on a sequential and repeated basis. The cost savings achieved under PBR ultimately leads to long term lower rates for customers.

In addition, performance measures and established metrics provide transparency on utility performance to help demonstrate that service is being provided safely, reliably, and efficiently. Earnings sharing allows customers to share in utility earnings if performance surpasses the established benchmark, and customers can obtain a consumer dividend for expected productivity gains that the utility achieves under a PBR plan.[7] Evidence shows that PBR plans deliver real value and are critical in aligning positive customer-centric outcomes with utility objectives.

With respect to the consideration of future test years, the EDCs note that future test years may provide some benefits compared to the Department's use of a historic test year, including aligning the revenue requirement more closely to the rate year following the rate case proceeding. Typically, a future test year helps better align O&M expenses based on Company forecasts than a historic test year. This prevents immediate earnings attrition when a utility can reasonably demonstrate that its costs for the rate year following a rate proceeding will be higher than the historic test year. However, alignment of a forward test year with capital spending needs may be more challenging, and reconciling mechanisms may still be needed to ensure that revenues can adequately support investment needs.

[6] Nick Crowley and Mark Meitzen, "Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities," *Utilities Policy,* 72 (2021).

[7] MA Rate Task Force Presentation, "Decoupling and Capital Recovery," October 22, 2025, 39.

Moreover, adopting the use of a future test year on its own does not solve for the fact that the EDCs costs would immediately outpace the level of costs built into rates *the first year after the rate year*, meaning that some other mechanism would be required after the first rate year in order to maintain alignment of rates with costs. Simply put, utilities, like other industries, have only two choices when their revenues become misaligned with their cost structure: 1) increase revenues to align with their costs (for utilities, this is achieved through a rate case, reconciling mechanism, or other regulatory framework such as PBR) or 2) adjust its cost structure to align with available revenues (i.e., to reduce investment levels or O&M expenditures) in order to align its costs with its revenues.

Discontinuing revenue decoupling and transitioning capital recovery into base rates.

The Straw Proposal recommends recoupling electric sales with revenues in order to incentivize EDCs to promote and expedite electrification strategies. While the EDCs do not disagree with the rationale for such an incentive, the current reality is that decoupling remains a necessary feature of the EDC regulatory framework. The Straw Proposal suggests that reintroduction of recoupling would allow the EDCs to support necessary capital investments through incremental revenue as well as fund incremental customer incentives for electrification. As the EDCs note in their ESMP Reply Comments, incremental revenue in the near-term is unlikely to be sufficient to support necessary investments. Fundamentally, the timing and scale of anticipated sales growth is not aligned with system investment need. Anticipatory investment is a necessary precursor to electrification of heat and transport and DER adoption, such that meaningful revenue support from incremental sales will not be available until such investments in the system have already been made.

In considering recoupling, it is also critical to consider the potential implications of the changes in future rate design. First, recoupling introduces revenue risk to the EDCs which inherently means that rate designs must limit this risk to preserve the EDCs ability to continue to invest in the electric grid. Decoupling was first introduced to eliminate this risk and encourage the EDCs (and LDCs) to expand and proactively promote energy efficiency programs. A byproduct of decoupling was also to give the EDCs comfort to introduce new rate designs that would potentially put revenue at risk in a recoupled framework. For example, the EDCs recently introduced heat pump rates for residential customers and demand charge alternative rates for electric vehicle charging stations. Such rates place revenue at risk under recoupling in ways that are likely to be counterproductive to advancing innovative rates designs.

Additional Straw Proposal items related to ratemaking frameworks

Beyond the comments above, the EDCs offer comments on additional selected elements of the Straw Proposal related to ratemaking frameworks:

- Innovation frameworks: the EDCs agree there is value in considering frameworks for innovation to test products and services that have potential to benefit customers;
- Capex/opex equalization: the EDCs agree that there is value in considering mechanisms in the near term to support more equal regulatory treatment of potential opex solutions such as NWAs, including shared savings mechanisms or PIMs. Given the potential limitations of totex regulation that the EDCs have described in both the ESMP Reply Comments and Rates Task Force, it is not clear that it would be worthwhile to expend DPU and stakeholder resources on an investigation into totex.
- Load Management PIM: while the EDCs support evaluation of potential PIMs to support load management, it is important that any PIM be designed to effectively align with the desired outcome/impact (avoided distribution system investments) and that EDCs have sufficient levers available to influence the outcome. It will be critical to better understand potential interactions of DERs and electrification in influencing target outcomes, for example, as well as to consider that aggregate views of system peak or load factor may not be meaningful indicators of an EDC's ability to avoid distribution system investments.

2. *Rate Design Recommendations*

The EDCs agree with the Straw Proposal's recognition that movement toward more cost-reflective rate design for all elements of the customer bill, including policy-related costs, is critical for mitigating system costs and improving efficiency, fairness, and affordability for residential customers. Further, the EDCs appreciate the Straw Proposal's recognition that rates will need to evolve over time with system and customer needs, and emphasis on supporting vulnerable customers.

Similar to the recommendations on regulatory mechanisms, the EDCs are concerned that the recommendations for a specific rate design are premature. This is especially true given DPU's opening of its investigation into rate structures and bills in D.P.U. 25-200, which will consider many of the issues raised by the DOER and gather evidence at the same time. The Straw Proposal's recommended rate design is based on several assumptions derived from the high-level insights provided by the Task Force process and has not been supported by analysis of utility-specific data.

The EDCs note that consideration and implementation of any specific statewide rate design solution must be supported by robust analysis, including an assessment of peak periods and whether system peaks are (and will always be) aligned with distribution system peaks, which may vary by EDC or location, and must take into account bill impacts of any change, which have not yet been estimated or evaluated. Customers may be unnecessarily and unduly harmed without a detailed examination of potential bill impacts and potential mitigation measures, if applicable. While the Straw Proposal recommends ongoing analysis of AMI data to protect customers after the single proposed rate design is in place, the EDCs recommend that upfront utility-specific analysis of alternative rate design options is critical for protecting customers and ensuring the success of AMI-enabled rate design.

The Straw Proposal recommends statewide adoption of a default, single time-of-use ("TOU") rate for supply, distribution, and transmission, with a five-hour peak period from 3-8pm on non-holiday weekdays and summer and non-summer differentiation. The EDCs have concerns regarding potential customer impacts and the efficacy of such a uniform approach. DOER proposes that customers cannot opt out with the exception of low-income customers because of concerns regarding affordability. Concerns about affordability should not be limited to low-income customers as such a significant change to the default rate design would result in bill impacts for a wide swath of residential customers, which have not yet been meaningfully evaluated. Further, the Straw Proposal does not consider that the efficacy of the recommended default TOU supply rate with respect to its stated rate design objectives would be dampened by the competitive retail supply market and continued growth in municipal aggregation where rate offerings may not be aligned.

The Straw Proposal derives the recommended peak period from an analysis of ISO-NE system peaks and posits that providing a single peak period across supply and delivery rates will "support positive customer responses, likely outweighing any granularity provided with multiple peak periods."[8] While the EDCs agree that simplicity of rate design could facilitate customers' management of their electricity usage, selection of a specific single peak period for supply and distribution is premature without robust analysis of data to determine whether distribution system peaks are indeed aligned with ISO-NE peaks. If peaks are not fully aligned, customer-centric adjustments may be made to align supply and distribution TOU periods fully or to some degree, if determined to be reasonable in the rate design process. Local distribution system peaks drive grid investment needs and are not necessarily aligned with ISO-NE system peak demand. There is potential for further misalignment between system and local distribution peaks as more electric vehicles and heat pumps are deployed,[9] shifting residential load profiles and peak demand on local distribution systems. Failure to capture any such divergence in the design of rates will result in price signals that do not sufficiently reflect costs, that reduce or eliminate any

[8] Straw Proposal, 13.

[9] See Straw Proposal, 10.

benefits of new rate designs, and that potentially increase costs and inequities relative to current rates. This potential outcome, as well as the limitations in the impact of the Straw Proposal's Basic Service TOU described above, reinforce the need for separate investigation of supply and distribution time-varying rates, as has been the Department's intent.

Notably, the Straw Proposal excludes discussion of demand charges for recovery of distribution and transmission costs. As explained by the EDCs and Charles River Associates in presentations to the Task Force on June 9, 2025, demand charges may be designed with a customer-centric focus to minimize the risk of bill instability and facilitate simplicity and understanding.

Demand charges reflect how costs are incurred on the delivery system more closely than volumetric TOU charges and thus have greater potential for achieving the Straw Proposal's stated objectives of efficiency, fairness, and equity. As new residential load profiles emerge, driven by electric heat pump and EV charging adoption, demand charges may help avoid significant and unfair bill increases due to increased usage under traditional volumetric rates. In addition, customer usage of heat pumps tends to improve customer load factors, which is a favorable outcome under a demand charge-based rate design.[10] Demand charges are further likely to improve efficiency, fairness, and equity relative to volumetric TOU, as they provide more adequate fixed cost recovery from customers with distributed generation, thereby reducing uneconomic cross subsidies from net metering. The EDCs strongly urge that the Straw Proposal be revised to include consideration of multiple options for distribution rate design, inclusive of customer-centric demand charges.

3. Recommended Proceedings and Timing

The EDCs agree there is value in progressing Phase 2 of the Basic Service Proceeding to investigate time varying rates for Basic Service.

With respect to delivery rates, on December 15, 2025, the Department opened its investigation into charges on both electric and gas customer bills in D.P.U. 25-200.[11] The order states that the Department expects that DOER will submit a forthcoming petition requesting an investigation into electric rate design and regulatory mechanisms, and that the Department will soon open a docket for this proceeding.[12] The EDCs recommend that

---

[10] See, e.g., Brattle Group, "Heat Pump-Friendly Cost-Based Rate Designs," (January 2023), 9.

[11] D.P.U. 25-200, Vote and Order Opening Inquiry, December 15, 2025.

[12] Id, 23.

the Department's investigation into time-varying distribution rates should occur independently of broader investigations into ratemaking frameworks and should focus on cost-reflective rate design options and customer considerations. In addition, the Department has articulated its intent to investigate innovative cost recovery approaches and noted that such an investigation will require a lengthy inquiry to identify, analyze, and resolve many complex ratemaking issues, and is actively reviewing comments to inform the scope of such an investigation.[13]

The EDCs look forward to these proceedings and the opportunities they present for further discourse on the topics of ratemaking frameworks and rate design, and for continued collaboration with DOER and other members of the Massachusetts Rates Task Force.

Very Yours Truly,

Meghan McGuinness
Director, Regulatory Strategy
National Grid

Richard Chin
Manager, Rates (MA)
Eversource

Patrick Taylor
Chief Regulatory Counsel
Unitil

[13]D.P.U. 24-10/D.P..U. 24-11/D.P.U. 24-12 at 444; ESMP Phase II Procedural Notice (November 21, 2024).

To: Massachusetts Electric Rate Task Force
From: Prof. Christopher R. Knittel
Associate Dean for Climate and Sustainability
George P. Shultz Professor of Applied Economics
Director of the Center for Energy and Environmental Policy Research
Director of the MIT Climate Policy Center, and

Fischer J. Espiritu Argosino
Graduate Student, MIT Technology and Policy Program
Re: Recommendations for rate design reform
Date: December 19, 2025

Executive Summary
This comment evaluates the Massachusetts Electric Rates Task Force's proposed residential rate design reforms, with particular attention to Time-of-Use (TOU) pricing and modifications to fixed charge structures. Drawing on recent empirical and simulation-based analysis, we assess the implications of these reforms for electricity affordability, economic efficiency, and equity across households.

Our analysis indicates that the proposed adoption of TOU pricing represents a meaningful improvement over flat volumetric rates by more closely aligning retail electricity prices with underlying wholesale market conditions and transmission and distribution cost drivers. By concentrating higher prices during periods of peak system demand, TOU pricing reduces inefficiencies inherent in uniform pricing and mitigates the overcompensation of rooftop solar exports that occurs when generation is valued at flat retail rates. Simulation results show that TOU pricing delivers economically significant system-wide efficiency gains by improving the correspondence between retail prices and real-time utility costs.

We further find that shifting certain policy-related and delivery cost recoveries from volumetric rates toward non-bypassable fixed charges improves both economic efficiency and equity. Recovering fixed system costs through per-kWh charges disproportionately shifts costs onto customers without rooftop solar as rooftop solar adoption expands. Greater reliance on fixed charges ensures that all grid-connected households contribute to shared system and policy costs, reduces regressive cross-subsidies from lower-income non-adopters to higher-income solar adopters, and improves bill predictability for households without rooftop solar.

Together, TOU pricing and fixed charge reforms constitute an important step toward a more affordable, efficient, and equitable electricity rate structure in the Commonwealth. However, our analysis also makes clear that these reforms are not sufficient, on their own, to fully resolve the cost-shifting associated with rooftop solar under the current net metering framework. Even under TOU pricing, exported generation continues to be compensated at rates that exceed its marginal value to the system during periods of high solar output, and distribution-level costs associated with bidirectional power flows remain largely unpriced. As solar penetration increases, these residual cost shifts persist and place growing upward pressure on rates paid by customers without rooftop solar.

Accordingly, achieving a durable and equitable rate structure will require the Commonwealth to further modernize the net metering system itself by aligning export compensation more closely with real-time energy, transmission, and distribution costs. Rate design reform is a necessary foundation, but it cannot fully eliminate the structural inefficiencies and inequities created by administratively set retail export compensation.

I. Rooftop Solar is Linked with Higher Electricity Prices

The current Commonwealth net metering policy compensates rooftop solar exports at the retail electricity rate per kWh. This has supported the rapid adoption of rooftop solar in Massachusetts. However, recent data from the Energy Information Administration shows that rooftop solar generation in Massachusetts is among the highest in the US and has grown exponentially since 2010 (see Figure 1).

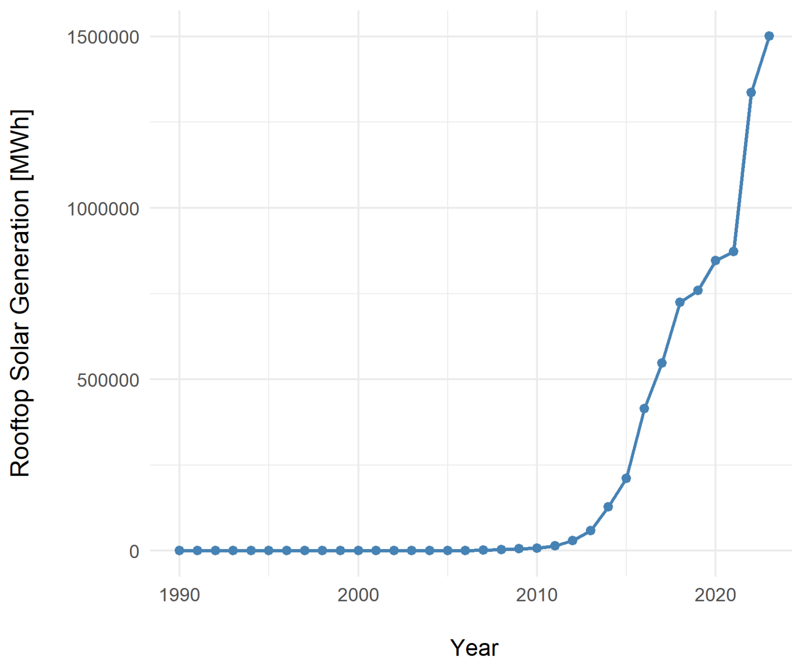

Figure 1: Rooftop solar generation in Massachusetts has risen exponentially since 2010.

Our recent work at the MIT Center for Energy and Environmental Policy Research (CEEPR) has found plausible evidence that rooftop solar generation expansion has led to higher residential electricity prices in the United States (Argosino and Knittel 2025). Using 25 years of state-level retail electricity prices across the continental US, we constructed an econometric model that controls for differences between states and years. Our results find that rooftop solar is robustly correlated with higher prices when compared with other generation technologies. We extend this analysis to dissect potential causal mechanisms through which rooftop solar may raise residential electricity prices. Using self-reported utility cost data from the Federal Energy Regulatory Commission, we are able to isolate capital expenditures along with operations and maintenance (O&M) costs associated with generation (G), transmission (T), distribution (D), and combined costs (G+T+D). Using a similar econometric framework, we find that rooftop solar is strongly linked with higher distribution and combined O&M costs. These results do not imply that rooftop solar is inherently inefficient, but rather that existing retail rate structures and net metering policies can amplify equity and cost-recovery pressures as penetration increases.

In this context, reforms that introduce temporal differentiation into retail rates—such as Time-of-Use pricing—serve as a necessary first step toward correcting these distortions, though they do not fully resolve them.

II. Align Net Metering Compensation with the Full Costs and Benefits of Rooftop Solar
The current Commonwealth net metering system compensates a household with rooftop solar that exports power into the grid at the full retail rate. There are two inefficiencies from this, one related to the compensation that these exports receive for the transmission and distribution portion of the retail rate, and the second related to the energy portion of the rate. As for the first, a significant portion of this full retail rate pays for the transmission and distribution networks associated with supplying electricity to consumers. One rationale for compensating these exports for the per-kWh transmission and distribution rate is that solar installations enable utilities to defer the costs of investment in their distribution networks. This ignores two features of an electricity grid. First, the potential deferrment benefits would only exist during peak time periods, as the distribution system is sized to handle peaks. Second, these rate structures often do not consider the strain that rooftop solar exports place on a distribution network that was not originally designed for bi-directional power flows. This adds administrative and physical complexity, which may place pressure on distribution O&M costs upwards.

The second inefficiency created by the current rate structure, combined with the current net metering policy, relates to the energy payment made to households exporting power into the grid. As solar penetration increases, the energy savings from solar fall; the extreme of this has already been observed in California, in the so-called "duck curve." Wholesale prices in the middle of the day are often near zero if not negative. Therefore, net metering without TOU is overcompensating rooftop solar injections into the grid for both the energy and distribution costs Schmalensee et al. (2015).

The shift towards a Time-of-Use (TOU) based rate structure, as proposed by the Massachusetts Electric Rates Taskforce, would take a meaningful step towards alleviating the cost shift associated with net metering because it selects a peak-period coincident with peak wholesale electricity, transmission, and distribution costs. Since these peaks diverge from rooftop solar production peaks, their exports would be compensated at the off-peak price, which would be lower than the current retail price. By reducing the compensation for exports during these peak periods, rooftop solar owners would effectively pay a rate that's more reflective of the operational strain they may place on the distribution network.

III. Fixed Charges to Reduce Cost Burden on Low-Income Households
Another feature of the current residential electricity rates is the use of volumetric rates to recover costs associated with policies like solar subsidies, energy efficiency, and transmission and distribution charges. By paying for these "fixed" costs through a volumetric rate, rooftop solar owners pay less towards these costs, often even zero, than other households connected to the grid, even though rooftop solar households are still benefiting from their services. The economically efficient way to pay for the fixed costs associated with running an electricity grid is through a fixed connection charge (or through the tax base), rather than a volumetric rate. We discuss this in the

paper by analyzing two different rate structures: one in Massachusetts for a household without rooftop solar and one in New Hampshire with rooftop solar. The MA bill showed a fixed customer charge of $10, whereas the NH bill charges about $35. These higher fixed costs mean that even when the property is exporting electricity, the costs associated with delivery and other policies are still subtracted from their compensation, regardless of how much they export. This enables the utility to reliably cover its costs from both solar and non-solar customers, which helps to alleviate cost shifting.

For these reasons, the proposed conversion of certain public benefits line items from volumetric to fixed charges would likely create a more stable and efficient stream of funding for these programs. In addition to reducing cost shifting, greater reliance on fixed charges improves bill predictability for non-solar households by reducing their exposure to rising volumetric rates driven by declining sales.

IV. Equity Benefits from the Proposed Rate Design

A transition toward TOU pricing and greater reliance on non-bypassable fixed charges would also meaningfully improve equity in the Commonwealth's rate structure. As documented in Burger, Knittel, and Pérez-Arriaga (2020), current net energy metering policy generates substantial intra-class cost shifting because participating households tend to be higher-income and face fewer barriers to solar adoption, while non-adopters—disproportionately lower-income—face higher per-kWh charges to sustain retail compensation levels. Under inefficient residual cost recovery through volumetric rates, adoption of rooftop solar increases average expenditures for non-adopters, and these effects can be large at higher penetration levels. Recovering residual costs through fixed charges instead of volumetric rates reduces these regressive cost shifts by ensuring all customers contribute to grid and policy costs proportionately, rather than shifting costs onto those least able to pay. These results demonstrate that current rate structures relying heavily on volumetric charges and flat export compensation yield unintended and inequitable cross-subsidies that the proposed reforms would meaningfully reduce.

The empirical evidence in Burger, Knittel, Perez-Arriaga, et al. (2020) further reinforces the equity benefits of rate design reform. Using high-frequency consumption data for over 100,000 households matched with Census income characteristics, the authors show that transitioning from traditional volumetric tariffs to more economically efficient two-part tariffs—combining time-varying energy prices with fixed charges—can lower expenditures for lower-income households relative to standard flat rates. Importantly, they find that modest adjustments to fixed charge design can preserve economic efficiency while avoiding regressivity, providing regulators with practical levers to balance efficiency and fairness. When combined with the efficiency-enhancing TOU principles demonstrated in Hinchberger et al. (2024), a Massachusetts rate structure using time-varying prices and appropriately calibrated fixed charges aligns retail rates with actual system costs while ensuring that residual cost recovery does not disproportionately burden low-income households. These reforms, therefore, represent not only an economically efficient redesign but also a materially more equitable framework for financing the Commonwealth's electricity system.

V. Economic Efficiency Benefits from the Proposed Rate Design

There exists empirical evidence that TOU pricing and other dynamic pricing structures yield gains in overall economic efficiency by aligning retail rates more closely to real-time costs of electricity production and delivery. Drawing on methodology from Hinchberger et al. (2024), we use real-time data on wholesale prices combined with new insights on real-time *expected* distribution costs to calculate the associated economic efficiency gains from dynamic pricing using data on wholesale electricity prices, delivery costs, and load.

Our simulation compares two rate structures. The first is a flat rate structure where customers are charged the same rate at any hour in the year. The second closely models the TOU rate structure proposed in the straw proposal, such that customers may be charged four potential rates: on-peak summer, off-peak summer, on-peak non-summer, and off-peak non-summer. We define on-peak as between the hours of 3 pm and 8 pm, and the summer months as June, July, August, and September.

Additionally, we test two strategies for allocating transmission and distribution (T&D) costs. The first allocates T&D costs evenly across every hour, such that the TOU rates are solely responsible for allocating these costs. The second allocates T&D costs based on the probability that a given hour has the peak load in that year. Both are simplifications; the former assumes T&D costs are allocated uniformly, while the latter assumes T&D costs are entirely driven by peaks.[1]

Our complete dataset covers the years 2020 through 2024. Since rates are set based on historical data, we estimate regression models that predict the retail prices within each rate category that would best capture the variation in wholesale real-time electricity prices and delivery costs from 2020 through 2023. We then use the resulting coefficients to predict those same costs in 2024.

We find that there are economically significant gains in rate efficiency associated with the proposed TOU pricing proposal in Figure 2. The metric we use to represent these gains is a re-normalized goodness-of-fit metric (R^2) where we statistically compare the variation between utility costs (real-time wholesale prices and delivery costs) and retail electricity prices. A re-normalized R^2 of 1 indicates perfect real-time pricing such that increases in this metric correspond to gains in economic efficiency.

We find that the proposed TOU rate generates system-wide economic efficiency gains of 2.52% when TD. Additionally, allocating transmission and distribution costs based on the hourly probability of a peak load event increases these gains to 5.85%.

These results demonstrate that the proposed TOU rate structure adequately covers high transmission and distribution costs incurred during hourly peak loads. It also boosts economic efficiency by better aligning dynamic utility costs with retail prices. Further efficiency gains can also be made through the probabilistic allocation of hourly delivery costs, reinforcing the case for dynamic pricing.

[1] Specifically, we define the load in each hour as a random variable, $y_i = \gamma_i + \varepsilon_i$, where γ_i is the observed load in that hour and ε has a Gumbel distribution with scale parameter β and is independent across hours. Under these assumptions, the probability that a given hour has the peak load over the course of a year is $P(Y_i = \max_j Y_j) = \frac{\exp(X_i/\beta)}{\sum_{k=1}^{n} \exp(X_k/\beta)}$. We then allocate the T&D costs based on these probabilities.

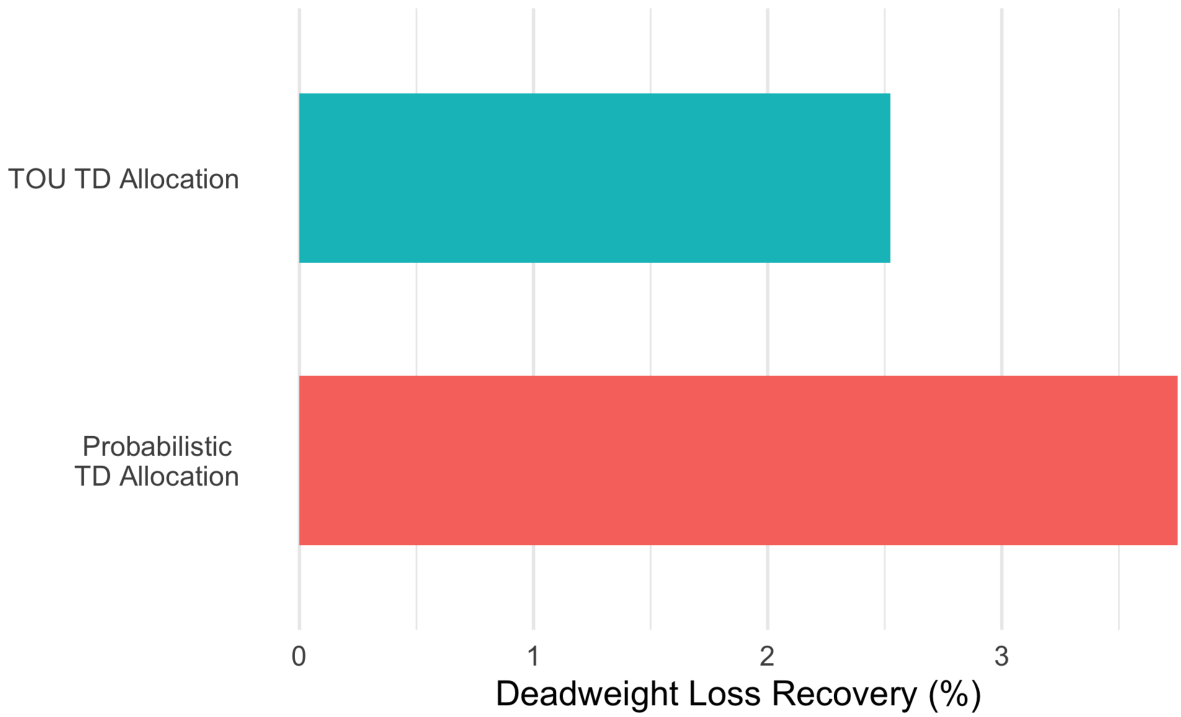

Figure 2: A probabilistic allocation of T&D costs in addition to a TOU rate may increase the system-wide economic efficiency of the system by recovering dead-weight-loss associated with a flat rate structure.

VI. Reduction in Overpayment for Rooftop Solar Exports

Our final numerical analysis finds evidence that a dynamic pricing system would further contribute to a more economically efficient system by more closely aligning the compensation paid to exported rooftop solar to its true value.

To illustrate this point, we develop a system based on rooftop solar hourly production curves provided by the MA-DOER generated for a hypothetical solar system in four different cities: Boston, Amherst, Fitchburg, and Chatham. We scale this system to service the sum of all residential demand in each city's respective load zone such that under a flat-billing structure, the exports of the rooftop solar equal the residential load. This effectively simulates a scenario in which all households within each load zone have rooftop solar and participate in net metering. We then use the same retail prices derived in Section IV to estimate the total rooftop solar compensation under flat and TOU rate structures. Similar to the economic efficiency analysis, we also test the impacts of allocating TD costs probabilistically.

When real-time system costs are in closer alignment with retail prices, rooftop solar exports would be valued less during times of high generation. This would lower overall export costs. We observe this in Figure 3, where a TOU rate reduces the payout of exports, and that further reductions can be made if TD costs are probabilistically allocated as discussed in Section IV.

Crucially, this analysis does not directly price the strain that rooftop solar exports place on the distribution network by introducing bi-directional power flows. Further analysis would be needed

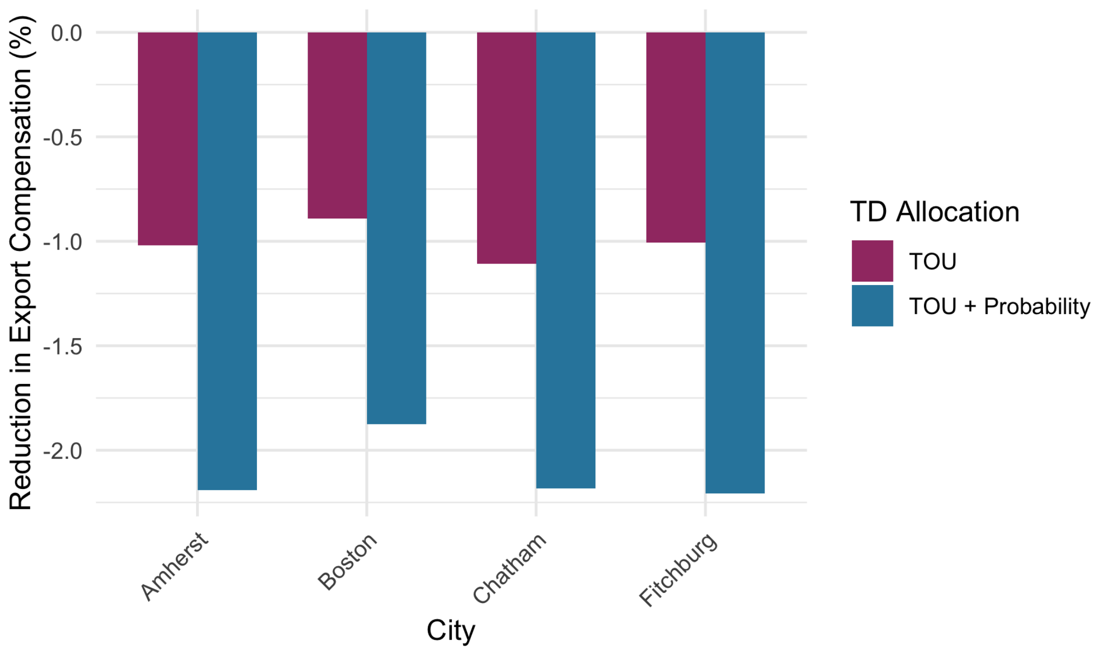

Figure 3: Percent change in solar export compensation for a solar system sized to meet the demands of all residential demand in each load zone. In all scenarios, dynamic pricing reduces rooftop solar export compensation by aligning its valuation more closely with the utility's real-time costs.

to understand the cost causality incurred by reverse power flows, such that they may be incorporated in future export compensation models. The reductions in compensation observed in these preliminary calculations are therefore conservative and demonstrate that even though a TOU rate structure takes steps towards cost-price alignment, additional interventions are necessary to further mitigate cost shifting created by net-metering.

While the proposed TOU pricing and fixed charge reforms represent meaningful steps toward improving cost alignment and reducing inefficiencies, our analysis makes clear that these measures alone are not sufficient to fully resolve the cost-shift associated with rooftop solar under the current net metering framework. Even under TOU pricing, net metering continues to compensate exported generation at rates that exceed its marginal system value during periods of high solar output, and does not explicitly account for the distribution-level costs associated with bidirectional power flows. As a result, residual cross-subsidies persist, particularly as solar penetration increases. Fully addressing these cost shifts will require the Commonwealth to modernize the net-metering system itself by aligning export compensation more closely with real-time energy, transmission, and distribution costs. Without complementary reform to net metering, rate design changes can mitigate—but not eliminate—the structural inequities and inefficiencies associated with rooftop solar compensation.

VII. Conclusion

Although our quantitative analysis shows that dynamic pricing does produce efficiency gains, the numerical results are not the focus; rather, we are primarily concerned about the overall trends that result from these analyses. Our evidence shows that the proposed time-of-use rate structure promotes economic efficiency in electricity systems by aligning retail rates more closely with wholesale prices and transmission-distribution peaks. This would enable the system to rightsize rooftop solar export compensation, ensuring customers pay rates commensurate with the demand they place on the system. Additionally, the proposed shift from volumetric policy charges to fixed rates would further alleviate solar-induced cost shifting and ease financial burdens on low-income households.

In section IV, we estimate that further economic efficiency gains can be made if transmission and distribution costs are allocated based on the probability that a particular hour will have a peak load event. This result emphasizes the benefits of rate structures that aim to dynamically allocate rates with expected real-time system costs. It is important to note, however, that there do exist diminishing returns to rate-structure complexity based on historical data (a key finding in Hinchberger et al. (2024)), so an efficient policy would ideally balance cost-price alignment with simplicity.

References

Argosino, Fischer J. Espiritu and Christopher R. Knittel (Dec. 2025). *Renewables and Electricity Affordability: Untangling Correlation from Causation*. Tech. rep. WP 2025-22. MIT Center for Energy and Environmental Policy Research (CEEPR). URL: https://ceepr.mit.edu/workingpaper/renewables-and-electricity-affordability-untangling-correlation-from-causation/.

Burger, Scott P., Christopher R. Knittel, Ignacio J. Perez-Arriaga, Ian Schneider, and Frederik vom Scheidt (2020). "The Efficiency and Distributional Effects of Alternative Residential Electricity Rate Designs". In: *The Energy Journal* 41.1, pp. 199–240. DOI: 10.5547/01956574.41.1.sbur. eprint: https://doi.org/10.5547/01956574.41.1.sbur. URL: https://doi.org/10.5547/01956574.41.1.sbur.

Burger, Scott P., Christopher R. Knittel, and Ignacio J. Pérez-Arriaga (Sept. 2020). *Quantifying the Distributional Impacts of Rooftop Solar PV Adoption Under Net Energy Metering*. Working Paper 2020-017. Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research (CEEPR). URL: https://ceepr.mit.edu/workingpaper/quantifying-the-distributional-impacts-of-rooftop-solar-pv-adoption-under-net-energy-metering/.

Hinchberger, Andrew J., Mark R. Jacobsen, Christopher R. Knittel, James M. Sallee, and Arthur A. van Benthem (Oct. 2024). *The Efficiency of Dynamic Energy Prices*. Tech. rep. CEEPR WP 2024-15. MIT Center for Energy and Environmental Policy Research. URL: https://ceepr.mit.edu/wp-content/uploads/2024/10/MIT-CEEPR-WP-2024-15.pdf.

Schmalensee, Richard, Vladimir Bulovi'c, Robert Armstrong, Carlos Batlle, Patrick Brown, John Deutch, Henry Jacoby, Robert Jaffe, Joel Jean, Raanan Miller, Francis O'Sullivan, John Parsons, Ignacio J. P'erez-Arriaga, Navid Seifkar, Robert Stoner, and Carlos Vergara (May 2015). *The Future of Solar Energy*. Tech. rep. An interdisciplinary MIT study. Cambridge, MA: MIT Energy Initiative, Massachusetts Institute of Technology. URL: https://energy.mit.edu/research/future-solar-energy/.

JERROLD OPPENHEIM
57 MIDDLE STREET
GLOUCESTER, MASSACHUSETTS 01930-5736
+1 (978) 283-0897; +1 (978) 335-6748
JerroldOpp@DemocracyAndRegulation.com

December 18, 2025

Austin Dawson
Deputy Director of Energy Supply and Rates
Via e-mail: austin.dawson@mass.gov
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

Cc: Chris Connolly
Clean Energy Coordinator
Chris.Connolly2@mass.gov

Mike Giovannielo
Data Analyst
Mike.Giovabbiello@mass.gov

Elizabeth Mahony
Commissioner
Elizabeth.Mahony@mass.gov

RE: Massachusetts Electric Rate Task Force, Ratemaking Straw Proposal (https://www.mass.gov/doc/rate-task-force-ratemaking-straw-proposal/download, November 24, 2025)– Comment of the Low-Income Weatherization and Fuel Assistance Program Network, the Low-Income Energy Affordability Network (LEAN) and the Massachusetts Energy Directors Association (MEDA)

THE COMMENTERS

1. This is the Comment on the above-captioned Ratemaking Straw Proposal of the Low-Income Weatherization and Fuel Assistance Program Network, the Low-Income Energy Affordability Network (LEAN), and the Massachusetts Energy Directors Association (MEDA), Its principal focus is the impact of the Proposal on low-income energy equity and affordability and for that reason, after an Introduction (sec. I) this Comment is limited to discussion of Time of Use (TOU or Time Varying Rates, TVR) prices (sec. II) and Increased Customer Charges (sec. III).
.

2. Brian Beote, Director of Energy Efficiency Operations of Action, Inc., and co-chair of LEAN, is a member of the Energy Efficiency Advisory Council (EEAC), representing the Low-Income Weatherization and Fuel Assistance Program Network.

3. G.L. c. 25, sec. 19(c) (Green Communities Act, St. 2008, c. 169, sec. 11) provides that “The low-income residential demand side management and education programs shall be implemented through the low-income weatherization and fuel assistance program network and shall be coordinated with all electric and gas distribution companies in the commonwealth with the objective of standardizing implementation.” The Low-Income Weatherization and Fuel Assistance Program Network are the agencies that implement the low-income programs under the Act that are a subject of the filed Term Reports. The Low-Income Energy Affordability Network (LEAN) is the organization of lead agencies in the low-income weatherization and fuel assistance program network. The Massachusetts Energy Directors Association (MEDA) is the association of Energy Directors of the agencies of the Low-Income Weatherization and Fuel Assistance Program Network.

4. The Commenters are in unique possession of information that can help inform the Department’s consideration of the Straw Proposal, including direct experience of low-income customers and the aforementioned agencies. Low-income consumers are finding it increasingly difficult to afford their energy bills due to both (a) volatile but generally increasing energy prices and (b) the general economic crisis, which is causing falling incomes. Rate design plays a critical role in making energy more affordable for low-income consumers.

5. Commenter agencies counsel utility customers about rates and payment options, and arrange rate payment assistance (including the Home Energy Assistance Program (HEAP or LIHEAP), arrearage management, and other forms of assistance.

COMMENT

I. INTRODUCTION

1. We appreciate this opportunity to Comment on concerns raised by the intersection of rate design, electrification, and the statutory mandate to prioritize affordability and equity. We appreciate the work of Department of Energy Resources (DOER) Staff in setting up the difficult issues that need resolution for the decades ahead and the information and points of view they have assembled. We also appreciate the concern for low-income bill impacts and appreciate the proposals for specific low-income protections.

In response to a request from DOER for information that would be helpful, we provided the information and data request, an edited version of which is attached.

We are also grateful for the support of the Joint Commenters convened by Conservation Law Foundation and the Comments they are filing in support of low-income protections, concern for cautious investigation of uncertain outcomes of new time-of-use and fixed charge rate designs, and concern that the Commonwealth needs to plan for managing the transition from heat pump rates so customers do not suffer bill shocks when the rate is phased out.

2. The Department of Public Utilities (DPU) is mandated, "with respect to itself and the entities it regulates, [to] prioritize affordability, [and] equity" as well

as safety, security, reliability of service, and greenhouse gas reduction. (G.L. c. 25, sec. 1A) Thus, consideration of system least-cost, cost-reflective, and operational efficiency is necessary but not sufficient to Massachusetts utility regulation.

We appreciate that "The Massachusetts Electric Rate Task Force brings together diverse stakeholders to reimagine how electric rates and the regulatory framework can drive an affordable, equitable, and decarbonized energy future. … [with the Purpose] To facilitate informed and forward-looking dialogue on electric rate design and regulatory mechanisms that advance Massachusetts' decarbonization and affordability goals." (Straw Proposal at 4) While average rate class bill levels are an important element of this discussion, affordability and equity also encompass individual household abilities to afford energy.

It is helpful to avoid thinking about affordability in an overly complex way. Key factors from customers' points of view are Energy Costs and Usage; all others are, more or less fungible levers of one or the other, *e.g.*, it matters little to customers whether usage is reduced by energy efficiency, heat pumps or thermostats, and it matters little whether prices are reduced by rate design (such as demand management of electric vehicles (EV) that many low-income customers will never own), rate policy, or decisions about supply and delivery thereof. Cost allocations in the ratemaking process should take cognizance of their impact on low-income and other vulnerable customers; cost-shifting to low-income customers should not be approved.

We have concerns about the Straw Proposal's impact on both scales in part because a focus on (average) least-cost, cost-reflective, and operational efficiency is relevant but not sufficient to establish affordability and equity. The Customer Charge and TOU rate proposals raise significant Low-Income bill impact concerns and warrant comprehensive research before they are considered for implementation. A more fully informed analysis, for example, requires more granular end-use bill information (*e.g.*, breakouts of seasonal homes, resistance heating, and vulnerable customers, as discussed below in this Comment) as well, of course, more definitive utility-specific rate and charges proposals. Significantly, it is important to understand, for example, that an average acceptable rate class bill impact can disguise unaffordable and inequitable bill impacts for half the households in that rate class.

II. TIME OF USE PRICES (TIME-VARYING RATES)

1. Although shifting load off the peak can have cost-saving impacts for the system, and thus for all bills, care should be taken not to increase low-income bills in the process. Low-income households are unlikely, without specific assistance that does not exist today at scale, to have technology to facilitate load shifting, *e.g.*, rooftop solar, battery storage, large appliances with controls. Unlike some C&I customers, they also do not have energy managers to manage their loads. "Managing" essential winter morning and evening heat loads could be particularly punishing for low-income families, who have relatively little flexible load. Furthermore, for those with Air Source Heat Pumps (ASHPs), heating technology operates most efficiently when thermostat settings are fixed around-the-clock.[1]

[1] At DOER's July 21, 2025 Presentation, Dr. Destenie Nock observed that "There is this RFF report which states "We find that low-income households exhibit significantly smaller peak demand reductions than other households. We estimate a difference of 12 percentage points." https://media.rff.org/documents/WP_25-

However, we acknowledge the value of time-of-use pricing where it can increase load factor, *i.e.*, use existing infrastructure more efficiently thereby reducing the need for new infrastructure while nevertheless increasing load and thereby revenue. The net result of such carefully targeted TOU is increased kWh throughput over substantially the same infrastructure, thus at less per kWh customer cost. The best current case for such TOU is incentives for off-peak charging of electric vehicles (EVs) so consideration should be given to starting opt-out TOU pricing for all EV charging.

Few low-income households have EVs, or a dedicated place to charge them, so not much low-income off-peak charging or vehicle-to-grid (VTG) resource (storage) is likely to materialize from them. But such off-peak EV-charging rates can be an effective way to both lower the bill impacts of EV charging for EV owners generally while thereby lowering total system costs.

2. Reliable data to project bill impacts do not exist, TOU bill impacts depend on the particulars of peak: off-peak ratios (even assuming revenue neutrality, bearing in mind that the higher the ratio, the more effective the rate is at inducing time-shifting for those who can do so and the more punishing for those who cannot), the level of low-income discount (including tiered discounts), individual customer load patterns, customer access to load control technology, and definitions of peak hours and peak seasons. Projecting bill impacts in the absence of such data is impossible. Further, load patterns, peak hours, and peak seasons are all subject to change over time, making system and customer projections bound to a particular time.

As an example of the weakness of rules of thumb based on existing data, the presumption that low-income usage is relatively flat over time (less "peaky") than non-low-income, and will therefore benefit from TOU pricing, is belied by data from a 2023 Eversource bill frequency analysis (D.P.U. Docket 24-15 Exh. Eversource response Attach. DPU 2-2 (Supp.), Jan. 31, 2025) showing that the median use of residential heating customers (Rate R3) is about 6900 kWh per year (575 kWh per month) while the low-income (Rate R4) median use is 8450 kWh per year (704 kWh per month).

As an example of the inherent instability due to the discontinuity of TOU rates is the current seasonal Heat Pump rate. Heat pump rates are a reasonable short-term solution since winter heat load is currently not on-peak. However, as noted in Task Force discussions, the peak is likely to shift to winter evenings and mornings at some (uncertain) point, challenging the rationale for the current Heat Pump rate design. The consequent shift from the electrification incentive created by the current Heat Pump rate design could then be seen as both a foreseen bait-and-switch and a difficult *increase* in low-income bills. This likelihood should be addressed now. Increased low-income rate discounts will be needed.

While at some point in the future, incomplete class load data may become available from AMI meters, the accuracy of end-use inferences from such data

---

04_vSszGzz.pdf (chat; Dr.Nock also cited findings related to automated thermostat settings for air conditioning which, however, do not apply to Heat Pump customers for the reason set out in the text) has not been established: there is no demonstration that the data will be statistically reliable (*e.g.*, not subject to systematic bias due to installation schedules), and universal individual data will not be available for years.

3. Time-of-use rates, including demand charges, can inequitably *increase* bills for those with essential electricity uses (*e.g*., oxygen and other durable medical equipment, medically necessary air conditioning), those who must be home all day (*e.g,*, elderly, frail, disabled, families with small children), and other vulnerable households, those who are at home during the day because their work requires nighttime shifts, and those without funds for, or are otherwise unable to adopt, solar/batteries/controlled appliances/*etc.* required to shift use to off-peak.

4. For these reasons, Low-income households should be exempted from TOU ("opt-in" enrollment). After enrollment only on an opt-in basis and a lengthy period of identification of households with essential electricity needs, as well as of education, outreach, hold harmless billing, "shadow billing" (*e.g.*, automated monthly comparison of non-TOU with TOU bills) and other bill stabilization strategies, should low-income TOU pricing be applied, and then with the ability to opt-out at any time.

III. INCREASED CUSTOMER CHARGES

1. Arithmetically, moving volumetric charges to fixed would lower per-kWh rates -- that seems to be at least part of the point, as rate relief for some -- but the perverse impact would be to reduce the incentive for Energy Efficiency for existing electricity use, increasing demand from what it would otherwise be, which would *increase* infrastructure costs over time. Thus blanket lower per-kWh charges would, for example, encourage inefficient electricity uses such as resistance heating[2] and pool pumps while discouraging beneficial electrification that increases electricity consumption, such as heat pumps. This appears to be the opposite of ides of supporting beneficial electrification.

2. From a low-income perspective, the arithmetic result is a quantity discount, *increasing* bills for customers with below-average consumption. Low-income customers[3] tend to be in the below-average-consumption group.

Some assert that low-income electricity consumption is about the same as non-low-income, so there should be no concern about inequitable impact of enacting a quantity discount for kWh. The assertion is neither factually based nor likely to be true in the future.

3. Detailed current bill frequency analyses would be helpful to any further conversation. To be useful in this context, such analyses would need to account for the low consumption of non-low-income second and seasonal homes, and non-low-income use of heat pumps for air conditioning rather than heat, as well

[2] This is already an attractive alternative for landlords who provide the means for heating but do not pay the operating cost thereof, since electric resistance heating is relatively inexpensive to install though ti is relatively expensive to operate.

[3] Excepting those with electric resistance heat, which though inexpensive to install is exceptionally inefficient. We are targeting such customers as budget allows for conversion to more electricity-efficient heat pumps.

as the relatively high consumption of low-income resistance heating (see above at point II.2.).

Therefore data are needed that separately identify by Rate (a) customers with electric resistance heat,[4] (b) customers using Heat Pumps primarily for air conditioning rather than for heat,[5] and (c) customers' second or seasonal homes, which use relatively few kWh annually.[6] We understand from DOER that the Massachusetts data necessary to reflect such factors does not exist and will not exist until a sufficient number of AMI meters has been installed for a sufficient period. Even then, as noted above, if not universal statewide data, we may have questions about the unsystematic sample that a partial AMI rollout might represent.

4. Further, in a future world of nearly-universal heat pumps, low-income homes will (by program protocol) be fully weatherized and also be relatively small consumers because their homes tend to be relatively small and lack pool pumps and other electricity-consuming luxuries.

Relatedly, net energy bill impacts of low-income electrification depend on originating fuel and electricity rate design. Note also that low-income electrification, energy efficiency, and weatherization are based on long-term programs that cannot reach every eligible customer at once.

5. A justification given for raising customer charges to encompass public policy charges is that it corrects the inequity of allowing solar customers, who are rarely low-income, to bypass public policy charges via net metering.

It is true that low-income uptake of solar incentives has been disproportionately low, largely because most low-income households do not own their own roof (*i.e.*, are renters) and, even when they do, their roofs are often not well situated with respect to sunlight or not sufficiently sound to hold solar panels.

Raising all, or a significant fraction of, low-income bills by raising customer charges to all customers is not an equitable solution to this concern. Solar customers are easy to identify; if they are underpaying for public benefits by by passing the policy charges included in per-kWh rates, the appropriate policy response is to raise solar charges on a targeted basis to correct the inequity.

A workable Low-income Community Shared Solar program is needed to support the equitable sharing of the Massachusetts solar resource. LEAN will be pleased to work with DOER and other stakeholders to design such a program.

6. Similarly, it is argued that high per-kWh charges penalize low-income customers with resistance heating. Here, too, a targeted solution is more equitable than raising low-income bills -- while not every resistance heating system can be converted to heat pumps at once, low-income resistance heating

[4] See immediately previous footnote.
[5] For non-low-income customers, this would tend to reduce electricity use compared to previous window air conditioners, and as compared to heating use.
[6] We assume that, almost by definition, these customers would be non-low-income on Rate 1 or Rate 3.

customers who sign up for conversion to heat pumps could be provided an additional low-income discount until their heat pumps can be installed.[7]

7. Volumetric rates therefore should be left as they are and not converted to fixed charges. Alternatively, moving policy costs to resources financed more progressively might be more equitable.

IV. CONCLUSION

For all of these reasons, the Low-Income Energy Affordability Network (LEAN), and the Massachusetts Energy Directors Association (MEDA) thank DOER and urge deeper consideration and more comprehensive analysis of ratemaking impacts on low-income affordability and equity.

Respectfully,

The Low-Income Weatherization and Fuel Assistance Program Network,
The Low-Income Energy Affordability Network, and
The Massachusetts Energy Directors Association

By their attorney,

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, Mass. 01930
978-283-0897, 978-335-6748
JerroldOpp@DemocracyAndRegulation.com

---

[7] The Landlord-Tenant split incentive makes this more difficult to address. Rental property-targeted incentives for Heat Pump conversions could help if rent adjustments could be mandated; perhaps a change in the Sanitary Code could mandate a transition. Same for inefficient appliances.

ATTACHMENT: DATA AND INFORMATION REQUESTS

(Please provide all data by utility, and utility/fuel pair where Heat Pump conversion - by rate, as well as statewide; rate refers to customer rate code, *i.e.*, R1 R2, R3, R4, *etc*. If ncecessary, please contact us to clarify Requests.)

Time of Use

1. Projected date seasonal peak shift (summer to winter) e.g., 2035?
   a) At that time, assuming heat pump rate is terminated, heat pump bill impact vs today's heat pump rates, by utility and rate
   b) At some point, the seasonal value of electricity use at high volumes for winter heat is predicted to change as peak load patterns change. As rates change to reflect new realities such as higher winter demands relative to summer (increasing the winter value of electricity), some who have invested in equipment responding to seasonal variation (today's relatively low electricity demand and discounted rates), such as heat pumps, may experience much higher heating bills and feel they have been victims of an unaffordable "bait and switch." What is the response?

2. Define precisely and completely "shadow billing."

3. Define precisely and completely "bill stabilization."

4. Describe all other possible low-income safeguards, such as hold harmless billing, and other safeguards.

5. Actual proposed peak/non-peak ratios by season by utility.

6. Bill impacts of proposed TOU rates (dollar and percentage), given existing load patterns, by rate, season, and by peak/off-peak for each season.
a) In calculating the impacts on current natural gas low-income (LI) customers, what is the monthly assumed (i) electrical baseload and (ii) AC load for LI ***whole house*** customers during peak periods?
b) What % of the loads specified in 5.a) above occurs in on-peak periods?
c) In calculating the impacts on current natural gas customers, what is the assumed (i) electrical baseload and (ii) AC load for Low Income ***apartment*** customers during peak periods, by month?
d) What % of the loads specified in 5.c) above occurs in on peak periods?
e) Repeat a) through d) above for natural gas customers converting to (non-central) electric heat pumps.
f) Repeat a) through d) above for electric customers using (i) electric resistance heating, (ii) heat pump heating, and (iii) a heating source other than electricity or gas.

7. All evidence that TOU rates will lower LI bills. Include full description of all assumptions, location, sample, climate zone, and whether cooling is accounted for.

8. All evidence of the accuracy and comprehensiveness of AMI data ability to indicate "non-shiftable loads."

9. All evidence of the accuracy and comprehensiveness of AMI data enabling access to "enabling technology," including full description of "enabling technology," and including cost and means of low-income access.

10. All evidence of the (a) availability and (b) uptake of "enabling technology."

11. Would the off-peak rate apply in all 12 months, except for the on-peak periods?

12. For each season, what would be the hourly time period for on-peak rate charges? Provide the complete basis anda data for this answer.

13. Confirm that holidays and weekends would not be part of any on-peak rate periods.

14. Would the application of TOU rates be revenue neutral for Transmission and Distribution costs? If not, explain the precise relationship.

15. What is the assumed number of LI customers (not just those LI on discount rate) that would be subject to the TOU rate?

14. (a) Provide all evidence with respect to what percentage of LI customers would opt for the TOU rate if given the choice? (b) If only that % of LI customers participated in the TOU option, what would the effect be on estimated IOU revenues? (c) Quantify the bill impacts on others of (a) 75%, (b) 90%, (c) 100% of LI customers opting out of TOU rates.

15. Would TOU rates apply to Commercial and Industrial customers in the same way as they apply to Residential customers?

16. For each rate, provide hourly load curves (shapes) and tables by month and season (bill frequency analysis in 50 kWh increments). Also:

a) Time of use by rate for special situations (*e.g.*, elderly, disabled, medical necessity, young children, other homebound, those without funds for, or otherwise unable to adopt solar/batteries/controlled appliances/etc. required to shift use to off-peak).

b) Bill Impacts of proposed TOU on (i) customers in each rate and (ii) households in each situation listed in 16. a), above.

17. Traditional bill frequency data presumably include non-LI seasonal homes, excluding which would raise annual average R1 (non-heat) and R3 (heat) median use, especially on the Cape and in the Berkshires. Thus the non-LI/LI non-heat consumption gap would probably be understated so non-LI seasonal.homes should be identified (e.g., usage below xx kWh) and excluded. Prepare the response to Q16 omitting seasonal homes.

18. R3-4 (heating) billing data are not appropriate for comparison without accounting for differences in saturation of (very inefficient) resistance heating, efficient HPs, and levels of Wx. (a) Prepare the response to Q16 separately for homes using resistance heating. (b) Prepare the response to Q16 assuming resistance heating homes are converted to heat pumps with full weatherization.

19. Please provide HP saturations in 2023 in each class by partials (presumably for air conditioning) and full house.

20. (a) To understand TOU/seasonal pricing, and the impact of raising fixed charges (which increase average per-kWh charges for lower consumption), in the context of electrification policy, it would be helpful to compare or project consumption at close to full HP saturation (including full Wx) of both LI and non-LI non-seasonal customers in order to better account for, *e.g.*, universal Wx (lowers consumption) but differences in home sizes (LI generally smaller so less space to heat), and current differences in HP and resistance heating.

(b) In reviewing such data, we need also to keep in mind the projected shift in seasonal peak from summer to winter as HP saturation increases.

(c) Load data (Q 16-20) should be aggregated statewide but also by individual territory (NGrid, Unitil, Eversource East, Eversource West, Cape Light) to show the different patterns. (d) Also by Climate Zones.

21. Preliminary analysis shows, for example, that a low-income customer will enjoy bill savings by switching from oil heat to a Heat Pump with Heat Pump rate. Please compute, by utility at each discount tier (a) an analysis of this savings, (b) bill impacts of the introduction of proposed TOU rates (higher summer peak), (c) bill impacts of such a TOU rate but shifting to a higher winter peak though retaining the HP rate, and (d) bill impacts of such a TOU rate but shifting to a higher winter peak without a HP rate.

<u>Increased customer charges</u>
22. Identify each specific components of the total electrical cost that would be absorbed into the customer charge.

23. Would each identified cost component be totally absorbed, or partially absorbed? If partially, specify percentage absorbed.

24. Restate response to Q. 16 (Bill frequency analysis) by 20 kWh increments by rate, identifying mean and median usage.

a) Account separately for part-time/seasonal homes
b) Bill impacts of each proposed customercharge increase at each usage increment,

25. Please provide all evidence with respect to the relationship of income to electricity usage, accounting separately for heat pump usage and excluding second and part-time homes.

26. (a) Please provide all evidence and data with respect to low-income participation in ratepayer-financed solar programs. (b) Please explain DOER's position, if any, with respect to expanding utility ownership of solar resources.

27. All evidence and data with respect to low-income participation in ratepayer-financed EV programs.

-end-

Date: December 19, 2025

Submitted electronically via email to: Austin.dawson@mass.gov

Austin Dawson
Deputy Director of Energy Supply and Rates
Massachusetts Department of Energy Resources (DOER)
100 Cambridge Street, 9th Floor
Boston, MA 02114

Re: Massachusetts DOER Ratemaking Straw Proposal

Dear Mr. Dawson,

On behalf of Northeast Energy Efficiency Partnerships (NEEP),[1] we are pleased to submit comments relative to the Massachusetts Department of Energy Resources (DOER)'s Ratemaking Straw Proposal. NEEP is a non-profit whose mission is to accelerate regional collaboration to promote advanced energy efficiency and related solutions in homes, buildings, industry, and communities. NEEP recognizes the importance of rate design as one of the crucial ways to address energy affordability as many states struggle to keep energy costs affordable for customers. Rate design is one of many tools to address affordability concerns and align customer and grid costs.

We thank DOER for the opportunity to provide input on this rate design proposal. We commend DOER for its work so far in advancing cutting-edge rate design practices through its Interagency Rates Working Group and associated research studies, Rate Task Force, and regulatory petitions. The following comments are intended to provide technical assistance and resources relating to rate design. In addition to the recommendations below, NEEP has tools and resources available and can offer direct technical assistance.

In these comments, NEEP outlines four key considerations:

- NEEP supports DOER's proposal to implement default seasonal TOU rates for residential customers.
- NEEP recommends DOER consider additional customer engagement and affordability measures.
- NEEP recommends DOER encourage the continued use of revenue decoupling with performance incentives to drive efficiency and electrification.
- If converting the efficiency charge into a fixed charge, NEEP encourages DOER to consider income-graduated fixed charges.

[1] These comments are offered by NEEP staff and do not necessarily represent the view of the NEEP Board of Directors, sponsors, or partners. NEEP is a 501 (c)(3) non-profit organization that does not lobby or litigate.

NEEP supports DOER's proposal to implement default seasonal TOU rates for residential customers.

DOER's proposal to implement default seasonal TOU rates for supply, distribution, and transmission is based on foundational principles of rate design and strategies that will align rates with grid costs and follow the principles of economic efficiency. Implementing TOU as a default (i.e., opt-out) rate with a robust educational campaign will ensure high levels of participation and grid-level impact. Additionally, incorporating flexibility that can adjust peak hours, season definitions, and rates can ensure that this rate continues to reflect grid costs as energy usage and system cost drivers change over time.

NEEP supports the default enrollment method paired with strong consumer outreach and complemented by robust energy efficiency programs. First, implementing this new rate as the default option, paired with strong consumer outreach and education, is a best practice to ensure that the rate can lead to large-scale changes in electricity usage patterns and consumer behaviors. This is crucial to generating system-wide benefits because it ensures a high rate of customer adoption, which is needed to reduce statewide system peaks and drive significant cost reductions. Implementation of other similar advanced rates across the country and past research has shown that opt-in rates do not generate significant enrollment among a customer base. Also, implementing the rate in a phased manner as proposed (by introducing time variation into each rate component over time) will help introduce customers to the concept of time-varying electric rates more gradually, limiting potential adverse customer experiences before customer knowledge has a chance to develop. DOER's proposed marketing, education, and outreach plan (discussed further below) will be the ultimate key to driving customer understanding and meaningful behavior change. Additionally, DOER can look for synergy with efficiency programs to increase customer education and advance adoption of appliances that can make participation in the TOU rate easier.

NEEP supports the way DOER has proposed to structure the rate. Incorporating time-varying pricing in all three main rate components- supply, distribution, and transmission- and combining all of this into one unified peak period - is a best practice that will lead to larger variation between peak and off-peak pricing, which is likely to drive more meaningful behavioral changes across the customer base. Additionally, the use of a single peak period across all bill components will facilitate customer understanding of the new rate and make it easier to communicate the best way to save money by taking advantage of lower off-peak rates. NEEP agrees with DOER that this approach is likely to maximize customer load shifting behavior and capture the majority of daily, monthly, and annual system peaks, thus accounting for the cost drivers that impact rates. NEEP reminds DOER that consumers will also have an opportunity to save energy through conservation and efficiency when on TOU rates– not just to shift load.

To ensure successful implementation of these rates, it will be important for DOER to start engagement early and use lessons from states that have implemented or attempted to implement TOU supply rates with municipal aggregators and competitive suppliers. California has managed coordination between regulated utilities and competitive electricity providers (CEPs), in orders (Decision 19-07-004 and Decision 18-12-004). The joint strategy involved timelines for CEPs to decide whether they would offer supply TOU rates in line with the utilities' TOU framework and coordination between the utilities and CEPs to minimize potential customer confusion. It is also important to note that there are barriers to suppliers participating in these rates. For example, a report in the proceeding investigating supply TOU rates in Maine (Docket No. 2024-00231) noted that these rates only appear as a single line item on the customer's bill, which does not allow them to accurately communicate the time-varying nature of TOU billing and limits their ability to influence customer behavior. Additionally, there are added costs for CEPs to develop and implement modern rate structures, such as upgrades to meters and billing software. Because CEPs are regulated differently than distribution utilities, they do not have cost recovery for such upgrades as regulated utilities do.

Finally, NEEP supports DOER's proposed methods of adjusting the rate and incorporating feedback and lessons learned over time. Adjustments to the timing of peak hours and the definition of peak seasons will ensure that the rate continues to charge customers prices based on the true cost of service as the electric system evolves (e.g., as the grid shifts from summer to winter peaking as expected in the next decade). Also, the degree to which this new rate would allow for flexibility (e.g., to adjust to new circumstances, resolve mistakes, and implement lessons learned) will further boost the rate's effectiveness and lead to better outcomes for customers. These principles, along with the other items included in DOER's proposed strategic implementation and enrollment and marketing, education, and outreach (MEO) plans, will help introduce the rate to customers with minimal interruptions, adverse experiences, or confusion.

NEEP recommends DOER consider additional customer engagement and affordability measures.

NEEP appreciates the consideration and stakeholder feedback that informs DOER's plan for customer engagement and affordability measures. NEEP supports DOER's customer engagement plan of utilizing shadow billing, opt-out provisions, and existing low-income bill discount programs to mitigate potential energy burden impacts of TOU rates on low-income customers. We also appreciate DOER's MEO plan to drive proactive, stakeholder-informed coordination among utilities before the TOU rates are implemented to raise awareness of this new rate and limit adverse customer experiences. Customer engagement and education are crucial to ensure that rates are adopted and able to achieve their intended goals.

DOER's proposal to not categorically delay TOU roll-out to low-income customers or create special opt-in provisions for low-income customers is bolstered by the presented research on the PG&E default TOU pilot, which found that TOU rates have a beneficial or neutral impact on low-income customers. This strategy also aligns with the concept that large-scale customer participation in the TOU rate is key to creating changes to system-level electricity usage.

NEEP also supports leveraging Advanced Metering Infrastructure (AMI) data to identify vulnerable customers who may exhibit energy-limiting behavior, customers with high energy burdens, or those who have non-shiftable loads. While AMI continues to roll out across the Commonwealth, there are existing utility and state data sources which could be used to identify vulnerable customers – such as those with chronic disconnections, high energy burdens, or users of durable medical equipment – for proactive outreach before default TOU rates are implemented.

In addition to the plan to connect these vulnerable customers with enabling technology and affordability measures highlighted in the proposal, NEEP encourages DOER to consider exemptions from TOU rates or hold harmless billing for these customers whose health and well-being may be more directly impacted by a bill increase. A step beyond shadow billing, hold harmless billing enrolls customers in both the standard flat rate and the TOU rate simultaneously and charges the customer at whichever rate yields the lower bill each month. It may also be appropriate to offer an opt-in TOU rate structure to this subset of particularly vulnerable customers in addition to low-income customers.

NEEP recommends DOER encourage the continued use of revenue decoupling with performance incentives to drive efficiency and electrification.

DOER recommends discontinuing decoupling on the premise that it is "not necessary to maintain commitment to demand-side resources" and that performance incentives and financial penalties are enough to encourage utilities to support demand-side resources. Decoupling has played an important role in aligning utility business models with efficiency and customer affordability because decoupling limits over-earning while still incentivizing utilities to electrify efficiently. Further, for efficiency, decoupling ensures that utilities are still made whole if energy usage lowers, removing the disincentive to investment in both energy efficiency and distributed energy resources, as utilities experience lower revenues from efficiency investments and distributed energy resources lower the need for additional infrastructure spending. Finally, decoupling plus electrification still provides a pathway for utilities to earn financial incentives as they can earn returns through growing infrastructure costs and performance incentives as proposed by DOER.

Decoupling is an important mechanism to ensure affordability as states electrify because it ensures utilities do not over earn as electricity usage rises. Decoupling removes the link between utility revenues and electricity sales as it includes a true-up mechanism that distributes revenues or increase rates so that utilities' earnings are in line with what was approved by regulators. This helps to maintain affordability for customers and secure earnings for utilities.

At a time of rising energy demand, revenue decoupling is more important than ever to protect customers and prevent utilities from over-earning. Since 2010, rates have increased 50% in Massachusetts. These higher electric costs are threatening electrification, as customers fear higher bills with adoption of electric devices. Decoupling helps to mitigate these impacts as it returns excess earnings to customers, pushing down rates. A study by Synapse Energy Economics found that because of revenue decoupling, EVs have the potential to reduce rates as EV use results in more revenue than costs for utilities. In Massachusetts, EVs have had a net impact of an additional $71.2 million dollars in excess revenues. Without decoupling, the excess revenues from use of electric appliances will flow to utilities.

NEEP recommends that DOER encourage the continued use of revenue decoupling with performance incentives. With the anticipated load growth from electrification, as well as other unknown factors, such as potential data center-driven load growth, it is important to keep decoupling in place to ensure there is not a risk of excess profits flowing to utilities at the expense of ratepayers. Further with decoupling, utilities will still be incentivized to electrify through returns on additional capital investment that will be required for electrification. Additionally, as highlighted in the straw proposal, performance incentives provide a pathway to incentivize electrification as they align electrification with utility shareholder incentives and can be tied to state policies. This provides a more focused tool to financially incentivize utilities.

If converting the efficiency charge into a fixed charge, NEEP encourages DOER to consider income-graduated fixed charges.

NEEP is concerned about some of the potential consequences of converting the energy efficiency reconciliation factor (EERF) into a fixed charge, as this could increase fixed charges by $16 - $18 a month for households. While this could help mitigate seasonal fluctuations on customer bills, a higher fixed charge could result in disproportionately higher energy bills for low-income customers and low energy users. If DPU accepts DOER's recommendation to pursue this policy shift, NEEP encourages DOER to consider income-graduated fixed charges as part of the proposal.

Research has shown that the average residential fixed charge in the U.S. is approximately $11 a month. Incorporating the EERF into the fixed charge would more than double this fee, putting Massachusetts utilities among the highest fixed charges in the country at nearly $30 per month. This would disproportionately impact low-income customers, who pay a higher portion of their income on energy than wealthier households, and increase their energy burdens. Similarly, for smaller and/or efficient households with low energy use, a higher fixed charge will disproportionately increase their energy bills.

Income-graduated fixed charges could provide an opportunity to ensure that at least low-income households are not disproportionately impacted. This mechanism would adjust the fixed charge of consumers' bills based on their incomes. This would make bills more equitable by reallocating a portion of fixed costs based on income level. This can remedy the disproportionately higher percentage of income that lower-income customers will pay into the proposed higher fixed fee. California has implemented this rate design with three tiers: low, moderate, and higher income. This helped the state lower volumetric rates across all classes and progressively distribute system costs through its fixed charge.

Conclusion

Overall, DOER's proposal is a significant step towards modernized ratemaking that aligns with goals for energy efficiency, electrification, and peak demand reductions, unlocking opportunities to lower bills and system costs. These comments are intended to support the work currently underway on DOER's Ratemaking Straw Proposal, and we appreciate the opportunity to provide input. In addition to the comments, NEEP is available to provide technical assistance and assist DOER in rate design best practices that accurately reflect electric system costs while promoting customer affordability, energy savings, and load shifting as Massachusetts continues to pursue strong climate and energy goals.

Sincerely,

Erin Cosgrove

Erin Cosgrove
Director, Policy and Programs
Northeast Energy Efficiency Partnerships
ecosgrove@neep.org

Luke Miller
Senior Associate, Policy and Programs
Northeast Energy Efficiency Partnerships
lmiller@neep.org

Abigail Brown
Senior Associate, Codes and Standards
Northeast Energy Efficiency Partnerships
abrown@neep.org

Comments of NRG on Massachusetts "Ratemaking Straw Proposal" from "Electric Rates Task Force"

I. Introduction

NRG appreciates the effort and diligence from the MA Department of Energy Resources ("DOER") team throughout the "Electric Rates Task Force" ("ERTF"), culminating with the release of the "Ratemaking Straw Proposal." We recognize the high volume of work that went into convening the expert presentations and stakeholder discussions.

The NRG Retail Companies provide competitive electric generation supply as well as other energy-related products and services to residential and non-residential customers in the Massachusetts competitive retail market. The NRG Retail Companies also currently provide electric generation supply to more than 30 cities and towns in Massachusetts through municipal aggregation programs. Across North America, NRG serves 8 million energy and energy services customers, including through its smart-home company, Vivint, which has a technology-development office in Boston.

Our vision is for every customer in the Commonwealth to have near full control over their electric bill. Indeed, as DOER has stated, implementing Time-Varying Rates ("TVR") is a critical opportunity to promote affordability in Massachusetts. With this control, NRG can provide our customers with the products, services, and insights to reduce their energy bills.

Today, customers in the Commonwealth have minimal control over their bills. The deployment of AMI is a foundational step toward empowering customers with that control. However, it is insufficient without data access/data settlement policies and rate design that sends the right price signals to customers. The "Ratemaking Straw Proposal" is a critical step toward sending the right price signals to customers and aligning cost allocation with cost causation. We urge the DOER to file the proposal with the Department of Public Utilities ("DPU") and to incorporate the recommendations we provide below.

Critically, the "Ratemaking Straw Proposal" will fail to realize its promise without proper data access and data settlement. As such, we strongly support the DOER's statement on Slide 47 that the "DPU investigation should also resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculations." DOER recommends this DPU investigation take place in the first half of 2026. Indeed, Electric Distribution Companies ("EDCs") must report interval data to ISO-NE for load settlement and capacity tag calculations for TVR to be possible. NRG appreciates and supports the DPU's statements on this topic in their Order from December 15, 2025, opening an investigation in DPU 25-200, but notes there is no timeline for DPU action.[1] **When DOER files their petition with the DPU in early 2026, DOER should urge the DPU to "resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculation" by the end of the first half of 2026.** Given statements from the EDCs regarding the longer timeframe they expect it to take for them to develop this capability, a decision by the DPU on these important issues by June 2026 is necessary to enable TVR consistent with DOER's desired timeframe.

We've structured the rest of our comments as follows in two sections:

1. For recommendations in the "Ratemaking Straw Proposal" that we strongly support, we note those under the heading "**NRG Strongly Supports these Ratemaking Recommendations from the "Ratemaking Straw Proposal."** NRG filed four sets of comments with the Interagency Rates Working Group ("IRWG"), and those comments detail our reasoning for strongly supporting these recommendations. For brevity, we avoid restating them here.

2. For recommendations in the "Ratemaking Straw Proposal" that require modifications, we propose modifications and our rationale in the section "Recommendations that Require Modification."

II. NRG Strongly Supports these Ratemaking Recommendations from the "Ratemaking Straw Proposal"

- **DOER Recommendation:** Design a single, consolidated TOU peak period across supply, distribution, and transmission (Slide 13)
- **DOER Recommendation**: Differentiate TOU rates by season (Slide 16)
- **DOER Recommendation**: TOU rate design should adapt to system conditions (Slide 19)
- **DOER Recommendation**: Automatically enroll all residential customers on TOU rate (Slide 22)
- **DOER Recommendation**: Allow low-income customers to opt-out and offer additional bill protections for low-income customers, such as shadow billing (Slides 23 and 24)

III. Recommendations that Require Modification

NRG strongly supports DOER's recommendation to "Allocate bill components to TOU periods based on cost causation/allocation" (Slide 15). However, we recommend several modifications

[1] In the recently issued Order opening an investigation in D.P.U. 25-200, DPU stated its intention to "open a new proceeding to investigate reporting of AMI interval data to ISO New England for load settlement and capacity tag calculations, accelerated switching, and dynamic rate-ready TVR offered by competitive suppliers and municipal aggregators." Order at 24. NRG applauds the DPU's acknowledgment that "resolving these issues is key to allowing competitive suppliers and muni aggregators to offer TVR and "improving customers' understanding and control over their electric bills." Order at 24

on transmission costs to enable ratepayers in Massachusetts to avoid the ISO-NE need captured on Slide 9 for "$7-9 billion in new transmission costs by 2050 if load growth is not managed."

DOER recommends that transmission costs should be "allocated to peak hours in all months." NRG agrees that this will enable customers who reduce their energy usage during these peak hours to reduce the transmission cost portion of their bill as well as the transmission costs that ISO-NE allocates to the relevant "Transmission Owner" for the customer. DOER should proceed with this recommendation, in part.

But this recommendation is insufficient for reducing the transmission costs for all customers in the Commonwealth, and the $7-$9 Billion in potential new transmission.

To avoid that need, we recommend that DOER's petition propose:

1. **Time-Varying Rates that accurately reflect the hours of the year that cause the need for new transmission**. This is consistent with DOER's statement on Slide 11 that "Cost studies that identify drivers of incremental system costs ensure that customer classes are properly assigned costs to serve that class." Under the "Ratemaking Straw Proposal," it appears that transmission costs would be spread evenly across the peak hours of all 12 months of the year. Customer usage in July will likely have a much greater impact on the need for new transmission than in April, and TVR should reflect that reality.

   To effectuate this recommendation, DOER should collaborate with DPU, the New England Conference of Public Utilities Commissioners ("NECPUC") and the New England States Committee on Electricity ("NESCOE") to urge ISO-NE to share the hours of the year that are driving the need for the new transmission investment cited in their "2050 Transmission Study," and the amount of load reduction needed to defer and avoid the investments. Furthermore, DOER should collaborate with the same entities to urge transmission owners to share the hours of the year that drive the need for "local reliability" projects, and the amount of load reduction needed to defer and avoid the investments. **We recommend that DOER's petition containing the "Ratemaking Straw Proposal" encourage DPU to convene stakeholders, including ISO-NE and transmission owners, to provide this information during the investigation phase in the first half of 2026**.

   Once those hours are identified, those potential marginal costs should be factored into TVR. In the long-term, all ratepayers will benefit from avoiding the $7-$9 Billion in transmission costs.

   As evidenced by transmission costs over the last 10 years, ratepayers will suffer from a muted price signal for avoiding new transmission. In August 2025, ISO-NE Regional Network Service costs (transmission) were $16,167/MW-mo or 37% of total wholesale costs.[2] In August 2015, it was about half that, at $8,700/MW-mo and 27% of total wholesale costs.[3] For all the focus on capacity costs, transmission cost are now several times higher than capacity costs.

2. For customers served by municipal aggregators and/or retail suppliers, ISO-NE should allocate transmission costs directly to those municipal aggregators and/or retail suppliers that wish to have that option, and not the relevant transmission owners for those customers. This is similar to how ISO-NE allocates capacity costs today and how PJM allocates both capacity and transmission costs. If municipal aggregators and retail suppliers were allocated these costs, they would be motivated to provide their customers with the products, tools, and insights that would allow customers to reduce usage during these peak hours. As a result, these customers would reduce the transmission portion of their bills, and reduce the amount of transmission that needs to be built in ISO-NE.

Under the status quo, transmission owners simply pass through these costs to customers, and in some cases, benefit from building additional transmission. Municipal aggregators and retail suppliers have additional motivation for enabling customers to manage these costs. While we recognize that neither DPU nor DOER have jurisdiction over such a change, we believe it is worth collaborating with NECPUC, NESCOE, and other stakeholders to explore what ISO-NE changes would be necessary to effectuate this recommendation.

Finally, DOER recommends a 5-hour window for the on-peak component of TOU rates. NRG recommends a shorter window, with 4-hours at most. It is unrealistic to expect customers to reduce their grid consumption for so long (e.g., turning the AC down or off during a heat wave) and enabling technologies such as storage typically lack 5-hour duration. Moreover, as slide 18 demonstrates, four hours will avoid the majority of costs that five hours would avoid. In the end, having more customers engaged will lead to higher total avoided costs.

If certain distribution networks peak outside of those four hours, a more targeted solution is likely appropriate.

Conclusion

NRG strongly supports many of DOER's "Rate Design Recommendations." However, when DOER petitions the DPU, we recommend that DOER:

---

[2] https://www.iso-ne.com/static-assets/documents/100028/2025_08_nlcr_final.pdf
[3] https://www.iso-ne.com/static-assets/documents/2015/11/2015_09_nlcr_final.pdf

1. Urge the DPU to “resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculation” by the end of the first half of 2026
2. Propose Time-Varying Rates that accurately reflect the hours of the year that cause the need for new transmission
3. Encourage DPU to convene stakeholders, including ISO-NE and transmission owners, to provide information during the investigation phase in the first half of 2026 regarding the hours that drive the need for new transmission

Thank you for your consideration of these comments and please contact us with any questions.

Travis Kavulla
Vice President, Regulatory Affairs
1825 K. St., NW, Suite 1203
Washington, D.C. 20006

c: 406-788-3419

Greg Geller

Founder and CEO, Stack Energy Consulting

P: (781) 808-6616

E: greg@stackenergyconsulting.com

W: Stack Energy Consulting

STACK ENERGY
CONSULTING

ORACLE | OPOWER

December 19, 2025 *Submitted electronically*

Austin Dawson
Deputy Director of Energy Supply and Rates
Department of Energy Resources
100 Cambridge St #1020
Boston, MA 02114

Re: Massachusetts Electric Rate Task Force – Ratemaking Straw Proposal

Dear Deputy Director Dawson:

On behalf of Opower, I am pleased to submit comments to the Massachusetts Department of Energy Resources (DOER) relative to the Ratemaking Straw Proposal presented to the Electric Rates Taskforce. Opower is part of Oracle Utilities, the largest software company dedicated to utility customer engagement. Opower's platform supports utility decarbonization, affordability, and energy management efforts. We implement behavioral energy efficiency, demand response, and customer engagement programs for 174 utilities across the US and around the world, including programs delivering energy efficiency savings in Massachusetts.

Thank you for your consideration of these comments. Please reach out with any questions.

Sincerely,

Samantha Caputo
Senior Manager, Regulatory Affairs and Market Development
Opower/Oracle
Samantha.Caputo@Oracle.com

Marketing, Outreach, and Education

DOER recommends the electric distribution companies (EDCs) jointly develop and implement a marketing, education, and outreach (MEO) plan with stakeholders. Oracle strongly encourages DOER to expand the recommendation to incorporate personalized and targeted outreach and education. Whether the EDCs implement an opt-in or opt-out time-vary rate (TVR), education will be a critical component to ensuring the desired outcomes with any future rate design are achieved and the straw proposal should provide guidance on this.

Providing clarity, choice, and engagement at every step of the TVR journey helps ensure a seamless transition. Leveraging digital solutions to support MEO plans can help educate utility customers about different TVR options, using personalized education reports and online tools. Digital solutions that leverage AMI data can provide customers with personalized cost forecasts for different rate plans based on their actual energy usage data. This helps customers determine the best plan for their needs and see how changing their behavior would affect their bills. For example, Evergy leveraged these tools when rolling out their opt-out TOU rate. By providing digital self-service tools and personalized outbound communication, they were able to pre-enroll 160k customers in their chosen time-based plan versus auto-enrolling in the default TOU plan. Evergy's efforts and results have been heralded by the Missouri Public Service Commission as a pinnacle initiative in the industry and a new standard for rolling out TVR nationally. Oracle encourages DOER to include a MEO recommendation aligned with providing personalized outbound communication and making web tools available for customers to learn and self-serve.

DOER's recommendations relative to MEO plans should include a multi-channel approach. Engagement delivered through multiple formats to reach a broad customer base can be done with web-based tools, email reports, print reports, and proactive alerts for high bill trends. By making new rate deign information easy to understand and by providing actionable advice, the EDCs can increase customer satisfaction while reducing implementation costs. For example, Evergy estimated two million dollars saved from billing-related calls avoided because of implementing a digital strategy for their MEO plan.

Oracle appreciates that the MEO plans do not need to wait to be implemented until a new TVR framework is established but encourages DOER to require the MEO plans include approaches for pre, during, and post implementation of new rate designs. This ensures a continued outreach and education plan is in place once new rates are deployed. To ensure the EDCs achieve the desired outcomes associated with implementing TVR, continued engagement with utility customers is important. Providing insights into peak versus off-peak usage and encouraging utility customers to shift their usage to off-peak hours can help customers benefit from TVR, help save them money, and reduce stain on the electric grid. These plans should also consider other efforts implemented by the EDCs alongside TVR MEO plans, such as energy efficiency programs, and how those can be leveraged to support TVR plans.

Regulatory Mechanisms

Oracle encourages DOER to incorporate a regulatory mechanism to ensure energy efficiency funding is consistent and reliable moving forward. Oracle recognizes that some reconciling mechanisms are no longer warranted, but DOER's recommendation to remove revenue decoupling jeopardizes the level of future investment in energy efficiency in the Commonwealth. While there are state policies in place that support demand side management programs, energy efficiency remains as a least cost resource for managing the electric grid and therefore it is important to ensure future rate structures incorporate a regulatory mechanism to support this. DOER should clearly outline its recommendation to support energy efficiency funding with or without revenue decoupling.

Oracle supports DOER's recommendation to design and implement a load management performance incentive mechanism (PIM) to incentivize EDCs to drive efficiency and affordability. The recommendation identifies that the PIM should be outcome-based, rather than program specific. Oracle supports an outcome-based approach but encourages DOER to identify the types of measures that can be used to achieve the desired outcomes. We recommend that energy efficiency is clearly defined within this recommendation, including structural and behavioral energy efficiency and demand flexibility.

PowerOptions
Powering Nonprofits

December 18, 2025 *Via Electronic Mail*

RE: Comments on Ratemaking Straw Proposal

To Austin Dawson and the Department of Energy Resources:

PowerOptions appreciates the opportunity to comment on the Ratemaking Straw Proposal developed through the Massachusetts Electric Rate Task Force. We commend DOER for organizing a thoughtful process that has brought diverse stakeholders together to consider how rate design and regulatory mechanisms can support a clean, affordable, and equitable energy future for the Commonwealth.

PowerOptions is a nonprofit energy consortium serving more than 500 public and nonprofit entities across New England, including municipalities, public schools, higher education, hospitals, senior living facilities, and public and private affordable housing. Our Members are mission-driven and budget-constrained, and they depend on stable, understandable energy costs to deliver essential services.

1. **Overall Direction**

We agree that the energy transition is at an inflection point and that rate design should actively support, rather than impede, cost-effective electrification. Rate structures that improve alignment between prices and system conditions can help control long-term costs, reduce the need for new infrastructure, and make better use of existing assets.

We also agree that well-designed time-varying rates are an important tool for improving affordability. When customers can shift usage away from high-cost hours, both they and the broader system can benefit. We appreciate the proposal's framing of rate design as a broad, system-wide tool, complemented by more targeted programs that can deliver local distribution benefits and support specific technologies.

As DOER proceeds toward a petition, we encourage continued emphasis on customer simplicity and transparency, alignment with cost causation, and coordination with existing long-term programs and contracts so that projects developed under prior rules are not unintentionally undermined.

2. **Consideration for C&I alongside Residential**

We appreciate that the Straw Proposal acknowledges the importance of commercial and industrial (C&I) rate design, even though many of the detailed examples are framed in residential terms. From PowerOptions' perspective, it is essential that C&I not be treated as an afterthought.

We recommend that DOER and, ultimately, the Department of Public Utilities commit to analogous, data-driven analysis for C&I customers whenever structural changes are proposed, and that the petition explicitly describe how C&I impact assessment and stakeholder input will be incorporated.

For small C&I customers that are today served on simple volumetric rates alongside residential customers, time-of-use (TOU) structures are a natural evolution. These customers can respond to TOU signals much like residential customers, provided that communication and support are tailored to small organizations that often lack dedicated energy staff.

For medium and large C&I customers, particularly public and nonprofit institutions, the situation is different. Delivery and demand charges often dominate the bill, and existing G-3 "time-of-use" structures already offer on-peak and off-peak delivery rates, but with very broad peak windows and minimal or no price differential between periods. As a result, many members experience these tariffs as essentially demand-based rates with only weak marginal incentives to shift load, which also reduces the value proposition of time-varying supply products relative to fixed, stable pricing. For this segment, updating the design of demand and delivery components to better reflect coincident peaks and local system constraints is at least as important as introducing new TOU energy rates. Energy-side changes should complement, rather than conflict with, the signals embedded in delivery charges.

3. **Cost Causation and Cross-Subsidization**

PowerOptions strongly supports the emphasis on efficiency, fairness, and equity as core rate design principles of the Department of Public Utilities, including the principle that each customer class should pay no more than the cost to serve that class. We appreciate the explicit focus on avoiding systematic cross-subsidization between and within classes, while still allowing for transparent, intentional policy support where appropriate.

We are encouraged by the proposal's use of marginal cost and cost-causation analysis to allocate major bill components. Many of our larger Members are already familiar with concepts such as coincident peaks for capacity and transmission; extending similar logic to a broader set of rate elements is sensible.

As DOER refines these recommendations, we encourage:

- Clear documentation of how each major cost category is assigned to classes and TOU periods.
- Explicit identification of any intentional cross-subsidies, including their policy rationale and expected magnitude.
- Careful attention to intra-class equity, especially for customers that operate many small, low-usage accounts (such as streetlights, group homes, and small municipal buildings) alongside larger facilities.

This transparency will help ensure that the move toward more cost-reflective rates is understood and accepted by public and nonprofit customers, even when some bill impacts are unfavorable.

4. Peak Period, Seasonality and DR / BESS Potential

PowerOptions supports the recommendation to design a single, consolidated TOU peak period across supply, transmission, and distribution. A consistent peak window will give customers clearer demand response and load-management signals and should make it easier to align operational strategies with both regional and local system needs.

We also agree with differentiating TOU rates by season, recognizing that annual peaks have historically occurred during summer months, while preserving flexibility to adjust designs if the system becomes winter-peaking as electrification grows. Customers will need time, data, and practical guidance to adjust behavior across seasons, so any future changes to seasonal definitions or peak periods should be phased in carefully to avoid complicating budgeting and operations for public entities.

We do, however, have concerns about the proposed five-hour summer peak window (3–8 p.m.). Many Member facilities will find it difficult to adjust load over that full duration, and most short-duration storage is designed around roughly four hours of discharge. Sustaining meaningful load reductions for all five hours is likely to be challenging without significant additional investment or operational changes. We recommend that DOER:

- Evaluate whether a four-hour peak window would achieve most of the intended system benefits while better matching realistic demand response and storage capabilities.
- If a five-hour window is retained, consider complementary program designs that help customers manage the additional hour, such as incentives for longer-duration storage,

advanced controls and automation, and thermal management strategies that safely extend effective response duration.

5. **Customer Protections and Enrollment**

We strongly support the emphasis on bill protections, including shadow billing and careful sequencing of implementation. Wherever practicable, we recommend:

- Optional shadow billing for at least one year prior to full TOU implementation for all customers, including C&I, so that public and nonprofit entities can understand expected bill changes and adjust operations and budgets before financial exposure begins.
- Rollout timing that takes account of seasonal volatility and budgetary timing constraints, avoiding periods when customers may experience the starkest swing from their current pricing or would be unable to adequately account for new pricing under current budget cycles.

We also appreciate the Straw Proposal's attention to opt-in and opt-out design. For 24/7 operations such as hospitals, emergency services, and some housing providers, any enrollment framework should recognize limited flexibility to curtail load during critical hours and should explore tailored participation options or alternative structures where appropriate.

6. **Competitive Suppliers and ISO-NE Settlement**

PowerOptions strongly agrees that competitive suppliers and municipal aggregations must be able to participate fully in the new TVR environment. Default Basic Service TOU will establish an important reference point, but customers should also be able to access innovative time-varying products through municipal aggregations and third-party suppliers.

A key enabler is resolving AMI interval data and ISO-NE load-settlement issues. Without accurate, timely interval data and "rate-ready" billing and settlement systems, third-party suppliers and aggregators will be unable to offer TOU products that line up with the proposed rate structures. That would undermine competition and could disadvantage customers who take competitive supply or participate in municipal aggregation.

We recommend that DOER:

- Highlight ISO-NE settlement readiness and interval-data availability as critical prerequisites for TVR implementation.
- Ensure that aggregators and competitive suppliers are included in the design, testing, and rollout of TVR-related systems and processes.

7. Public Benefits Fixed Charges and Policy Cost Recovery Consideration for Commercial Impact

We are generally supportive of aligning public-benefits charges with fixed charges when there is no strong causal relationship between those costs and an individual customer's usage. This can reduce seasonal bill volatility and avoid penalizing customers who electrify or invest in efficiency.

However, we believe it is important that these changes be evaluated not only for residential customers but also for C&I customers, including those in the public and nonprofit sectors. A per-meter fixed charge can have a disproportionate effect on low-usage accounts, such as small municipal buildings, group homes, streetlights, and common-area meters in affordable housing.

We therefore recommend that DOER:

- Include detailed bill-impact analysis for C&I customers, with a focus on low-usage accounts and entities that operate many small meters.
- Consider whether a pure per-meter design is appropriate for all classes, or whether modest differentiation by usage level or customer type is needed to avoid unintended burdens on low-usage, public-purpose customers.
- Clarify how public-benefits fixed charges will interact with other fixed components on the bill to ensure that overall fixed-charge levels remain reasonable.

Separately, we agree with DOER's observation that the proliferation of reconciling mechanisms has reduced transparency, diffused stakeholder participation, and limited the depth of review those costs receive relative to a full rate case. We support the direction of bringing more of these costs into base distribution rates, where they can be examined in a more comprehensive context and adjudicated with broader participation.

At the same time, we urge caution that incorporating large portfolios of policy-driven spending into base rates does not further obscure the underlying cost of energy or make it harder for customers to see what they are paying for. Rolling grid modernization, AMI, climate and electrification plans, EV infrastructure, and related initiatives into base rates should preserve clear visibility into the scale and purpose of those investments and should remain subject to rigorous cost-effectiveness testing and affordability review, even when the recovery mechanism shifts from reconciling factors to base rates.

8. Export Tariffs and Load Management Incentives

PowerOptions supports the use of marginal cost and cost-causation studies to inform both distribution cost allocation and the design of export tariffs for distributed energy resources. Many of our Members host or plan to host solar, storage, and other DERs under long-term contracts. A well-designed export tariff that reflects the value of DERs to both the bulk and distribution systems will be essential to maintaining confidence in these investments and encouraging further participation.

We also support the proposal's emphasis on outcome-based load-management performance mechanisms that focus on load factor, peak reduction, and local constraint relief rather than mandating specific technologies. For our Members, a technology-neutral approach is important. Different institutions will find different combinations of tools practical, including demand response, battery and thermal storage, flexible process loads, and behavioral strategies.

We also recognize the proposal's interest in moving from traditional revenue decoupling toward forms of recoupling that better align utility revenues with electrification and load growth. We are generally supportive of that direction, provided it is paired with strong load-management expectations and non-wires alternatives so that growth is guided toward beneficial uses. In particular, safeguards are needed to ensure that recoupling does not simply create a new incentive to pursue very large, energy-intensive loads such as data centers in ways that increase costs or local system stress for other customers.

We further support the idea of a regulatory "sandbox" or structured innovation space where utilities, customers, and third parties can test new rate structures and load-management approaches on a limited scale, with a clear pathway from pilots to broader deployment if results are positive.

9. Implementation, MEO and Stakeholder Engagement

Finally, we appreciate the Straw Proposal's focus on coordinated implementation and robust marketing, education, and outreach. Successful adoption of TOU and related reforms will depend as much on communication and support as on the specific rate formulas.

We encourage DOER, in its petition, to:

- Explicitly include aggregators, competitive suppliers, and other third-party implementers in implementation and MEO planning, not only utilities. These entities are often trusted advisors for the customers we serve.

- Recognize the distinct needs of public and nonprofit institutions by designing MEO materials and technical assistance that speak directly to facility managers, business officers, and governing boards, and that provide practical, sector-specific examples for responding to price signals.
- Consider establishing ongoing stakeholder forums or working groups that include representatives from municipalities, schools, hospitals, housing providers, and other nonprofit entities to monitor implementation, share lessons learned, and recommend adjustments over time.

PowerOptions is grateful for the substantial effort that DOER and Task Force participants have devoted to this Straw Proposal. We believe the framework outlined, including cost-reflective consolidated TOU rates, thoughtful customer protections, careful treatment of public-benefits costs, and outcome-based load-management incentives, provides a strong foundation for a DPU investigation into electric rates and the regulatory framework.

We look forward to continuing to contribute experience from our public and nonprofit membership, particularly on the C&I implications of TOU rate design, public-benefits cost recovery, and load management. Please do not hesitate to contact us if it would be helpful to discuss these comments in more detail.

Sincerely,

Jonathan Stout
Director, Policy & Market Development
PowerOptions
jstout@poweroptions.org

December 19, 2025

Written Comments of Rewiring America in Response to the Massachusetts Department of Energy Resources request for comments on their November 2025 Ratemaking Straw Proposal.

Dear Mr. Dawson,

Rewiring America appreciates the Department of Energy Resources' ("DOER") work with the Massachusetts Electric Rate Task Force ("Task Force"), and the effort that DOER put into forming the recommendations included in the Ratemaking Straw Proposal ("Straw Proposal"). Thank you for allowing us the opportunity to submit comments on the Straw Proposal recommendations and discuss its potential to improve energy affordability and support electrification goals in the Commonwealth.

Rewiring America is a leading national nonprofit focused on making American households the center of a clean, resilient energy future. We bring together policymakers, industry partners, and community leaders to accelerate that mission. Our work particularly focuses on reducing the upfront and ongoing costs of residential electrification, including through rate design and implementation strategies that improves heat pump affordability, encourages load shifting, and protects energy burdened households. Throughout 2025, Rewiring America participated in the Task Force and we look forward to continued participation in formal rate reform workstreams in the year ahead.

Introduction

Rewiring America broadly supports many of the recommendations included in the Straw Proposal, however we recommend that the DOER consider implementing a few changes to the proposed Time of Use ("TOU") rate design, and we also have concerns with the DOERs recommendations to eliminate revenue decoupling and their recommendation to move certain reconciling mechanisms into base rates, due to the unintended consequences that implementing these recommendations might have.

Specifically, we recommend that the DOER:

1. Recommend implementing default, seasonal TOU rates to support electrification and demand flexibility, while maintaining robust opt-out provisions and customer protections.
2. Reduce their proposed TOU on-peak period to 4 hours to improve bill predictability and to better enable customer load shifting behaviors.
3. Expand their recommended customer protections associated with TOU implementation to include broader opt-out provisions and extended shadow billing to provide bill estimates under all rate options to all residential customers.

4. Ensure that changes to rate structures and cost recovery mechanisms preserve and strengthen protections for low-income and medically vulnerable customers.
5. Further analyze the potential impacts of eliminating revenue decoupling (including interactions with existing pro-electrification, pro-energy-efficiency, and performance-based regulatory mechanisms) before ending revenue decoupling.
6. Further analyze the impacts of moving reconciling mechanisms into base rates to ensure that this doesn't result in reduced transparency or additional risk to customers and bill affordability.

Time Of Use Rates

TOU rates are an excellent tool for improving grid performance and electric affordability as utilities experience massive load growth. Well-designed TOU rates can reduce system costs, manage peak demand in a way that defers the need for infrastructure investments, and provide customers with greater flexibility and control over their energy bills through incentivizing load shifting to lower-demand (and lower-cost) time periods. Furthermore, integrating TOU rates with complementary programs and technologies, including energy efficiency, smart appliances, and demand flexibility offerings can enable opportunities for competitive third-party solutions such as virtual power plants ("VPPs"), which can aggregate customer flexibility and deliver system benefits at lower cost than traditional infrastructure investments.

TOU rates are particularly important for addressing heat pump affordability as residential electrification gains traction in Massachusetts. Electricity use tied to heat pumps is seasonally dependent, with the majority of space heating load occurring in the winter months when wholesale electricity prices, system conditions, and peak drivers are materially different than summer months. Without built-in seasonal differentiation in TOU rates, customers that rely on heat pumps for space heating will be exposed to pricing that is not reflective of the system costs that are caused by their usage. This misaligned price signaling will increase the risk of bill volatility for customers who rely on their heat pump for home heating, and will undermine the affordability of whole-home electrification. Well-designed seasonal TOU rates can help to better align winter off-peak pricing with periods of lower demand on the system, allowing customers to operate their heat pumps in a way that is both comfortable and affordable, while still rewarding efficient load management as the system begins to shift to winter peaking in the coming decade. Implementing TOU rates will support both near-term heat pump adoption and long-term system planning by ensuring that customers are not penalized for adopting efficient and clean heating technologies, and by ensuring that rate design is well-positioned to evolve as load patterns in the Commonwealth begin to shift.

Rewiring America strongly supports the implementation of TOU rates in Massachusetts, but we recommend that DOER reduce their proposed five hour on-peak period to a four hour on-peak period. A four-hour peak period would better balance cost reflectivity with customers ability to shift load without requiring excessive behavioral or technological changes. Shortening the peak period from five to four hours does not materially impact annual or monthly peak capture. Although shortening the on-peak period from five to four hours slightly reduces capture of the daily peak, daily peak demand is primarily relevant for energy supply costs, and the reduction in peak capture is modest. On balance, the improved customer responsiveness enabled by a four-hour on-peak period outweighs the incremental peak capture achieved with a five-hour window. For example, Maryland's TOU pilots for BGE, Pepco, and Delmarva used "relatively short" peak periods to "allow customers to respond more easily", and the pilot programs still produced peak-demand reductions between 9%–14% in summer, proving that shorter peak windows can both capture system peaks and support customer load-shifting.[1]

Additionally, Rewiring America recommends that DOER revise the Straw Proposal to offer *all* customers the ability to opt-out of TOU rates, and provide shadow billing for all customers and all rate types, including TOU rates, heat pump rates, EV rates, and any other specialized rates that may be adopted in the Commonwealth. This shadow billing should be considered an ongoing consumer protection tool rather than a one-time transitional measure, and as such it should be provided to all residential customers on an annual basis. Providing customers with regular bill comparisons using the customer's actual usage (leveraging Advanced Metering Infrastructure, or "AMI", data) will empower customers to make informed decisions about rate options and reduce the risk of bill increases, particularly for customers with less flexible loads, such as those with in-home electric medical devices.

Protections for Low-Income Customers

Rewiring America acknowledges and supports DOER's focus on protecting low-income customers throughout Massachusett's transition to time-varying rates, particularly shadow billing which has been used by utilities to great effect to educate customers about rate options, demonstrate the bill impacts of switching, and even to model the impacts of adopting a new distributed energy resource ("DER") or implementing load shifting behaviors under available rate options.[2] Despite our support for low-income customer protections like shadow billing, we have a few recommendations for the DOER to strengthen these protections in their straw proposal to better ensure that potential negative impacts to disadvantaged groups resulting from TOU rates are mitigated.

First, Rewiring America recommends that the DOER better explain and expand upon their shadow billing recommendations. We recommend that the DOER and the D.P.U. explicitly define "shadow billing" as a parallel calculation of a customer's bill using actual usage data under available rate options. We also support enabling shadow billing in the form of personalized rate calculators and rate comparison reports as a permanent functionality for *all* customers to support ongoing customer rate awareness and beneficial rate switching. Due to evolving rate designs, and changing customer behavioral patterns as home and vehicle

---

[1]https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pd
f

[2] Rewiring America notes that Shadow Billing functionality in the form of rate calculators and personalized rate comparison reports is a valuable functionality that should be enabled for all customers, not just low income customers.

electrification increases, ongoing shadow billing is particularly essential to ensure that low-income customers are not inadvertently harmed over time.

Second, Rewiring America is strongly supportive of maintaining whole-bill low-income discount tiers. Whole-bill discounts are critical to ensuring that the DOERs proposed increase to fixed charges, in addition to other unavoidable costs, do not disproportionately burden low-income households, and particularly households that have a limited ability to shift load.

Finally, Rewiring America supports the concerns raised by Conservation Law Foundation (CLF) regarding default enrollment of customers with medical devices onto TOU rates. However, it is important that protections for medically vulnerable customers do not inadvertently exclude or stigmatize low-income customers. Customer protections need to be designed to be inclusive, flexible, and responsive to individual household needs rather than relying on narrow eligibility categories.

Perpetual Bill Guarantee for Low Income Customers

Looking ahead, Massachusetts customers should have access to a portfolio of rate options rather than a single default. A default TOU rate could be paired with optional alternatives, such as a flat rate, a higher-differential TOU rate, or a three-period TOU rate designed for EV drivers. If each option is cost-based and revenue-neutral, differences in household load profiles will inevitably create structural winners and losers across rate designs. To address this concern for low-income customers, the Commonwealth could offer low income customers a perpetual bill guarantee.

Under this approach low-income customers would be retroactively credited annually for any overage between their actual bill and what they would have paid under the lowest-cost available rate. Customers could then be auto-enrolled in that lowest-cost rate for the following year, with the same bill comparison and protection applied on an ongoing basis.[3] This structure removes the risk of rate selection for low-income households and has the potential to materially improve affordability for customers facing high energy burdens. It may also encourage low income customers to try out new rate options that may offer bill savings opportunities without taking on the risk of their bills increasing.

Customer Outreach and Rate Implementation

Rewiring America is supportive of DOER's recommendations for implementing more robust customer outreach and education to improve TOU implementation and ease customer

---

[3] Con Edison in New York currently offers a one-year bill guarantee program for residential heat pump customers that move onto a specific demand-based rate. This bill guarantee serves a different purpose than the above proposal (i.e., encourage rate switching for heat pump customers) and is limited to a one-year term and comparison with only one other rate option. But the broad bill protection concept is similar to the Perpetual Bill Guarantee proposal above. See: https://www.coned.com/en/accounts-billing/select-pricing-plan.

adjustments to the new rate structure. Robust customer outreach is essential for ensuring that customers understand not only the mechanics of how a rate works, but also how rate changes may impact their bills and new opportunities that arise to manage bills through load shifting, electrification, and DER adoption. We recommend that the D.P.U. require utilities to provide more specific and actionable guidance, including education on behavioral and device-enabled load shifting, such as rate-aware scheduling enabled by smart thermostats, water heater timers, optimal timing for EV charging, and optimal timing for operating appliances such as washing machines and dishwashers under the TOU rates. Customer education and outreach should focus not only on explaining rates, but also on clearly demonstrating how customers can save money under new rate structures.

Utilities should enable all customers to have access to rate calculators that leverage historical AMI usage data to provide personalized rate comparisons (also known as “shadow billing”). These rate calculators should be integrated into the inbound and outbound channels accessed most frequently by customers, including the MyAccount Portal, mobile applications, chatbots, and contact center tools. For example, a utility customer service representative assisting a customer with a high bill complaint could use the rate comparison tool to determine if the customer is on the best available rate option for their individual load profile. Utilities should additionally deliver proactive, personalized rate comparison reports to each customer at least once per year to promote beneficial rate switching.

An additional feature of rate comparison calculators is the ability to simulate the prospective bill impacts of adopting load shifting behaviors, purchasing an EV, installing a heat pump, or adopting another DER. This simulation can be achieved through the application of load modifiers to a customer's historic hourly consumption and processed through the customer’s current and available rate options. Optional simulations are valuable for helping a customer with exploring the savings potential of adopting behavioral or device-enabled load shifting or anticipating the bill impact of electrification under various rate options. In this way, rate calculators can help customers incorporate operating cost and rate selection into investment decisions for home energy upgrades.

Fixed Charges and Reconciliation Mechanisms

Rewiring America supports the DOER recommendation to move reconciling mechanisms into base rates, as this reduces bill complexity and limits the proliferation of riders. Most importantly, this would require utilities—not ratepayers—to assume revenue recovery risk that the utilities are uniquely positioned to manage. Incorporating these costs into base rates can also have the added benefit of improving transparency and reducing the utilities’ ability to introduce additional cost recovery mechanisms outside of rate cases (i.e., single-issue ratemaking).

Rewiring America supports DOER’s recommendation to move recovery of certain public benefit programs, specifically the Energy Efficiency Reconciliation Factor (“EERF”) and the Residential Assistance Adjustment Factor (“RAAF”), from volumetric riders to fixed customer charges. As noted in the Long-Term Ratemaking Study, reducing volumetric charges for customers is an effective lever to improve cost competitiveness of electrification. The DOER cited Massachusetts-specific data in their Policy Fixed Charge and Heat Pump rates presentation that indicates that low-income customers are twice as likely to rely on electric resistance heating compared to non-low-income households.[4] Recovering public benefits through fixed charges could reduce volumetric rates and benefit these customers. Additionally, under the current structure, some customers, particularly customers with solar (who tend to have higher incomes) can bypass certain public benefit charges as these are currently paid for volumetrically. Making these charges non-bypassable ensures a more equitable contribution to programs that benefit the broader public. However, these increased fixed charges need to be implemented in conjunction with whole bill low-income discount rates as they are essential for preventing additional burden to low-income customers.

Proposal to Discontinue Revenue Decoupling

Rewiring America appreciates DOER's overarching intent to align utility incentives with electrification and energy efficiency goals. However, we have concerns that eliminating revenue decoupling may not be the most effective, or most appropriate, mechanism to achieve these outcomes. Massachusetts already has multiple policy and regulatory levers in place to incentivize fuel switching, load growth, and energy efficiency, including performance-based incentives, program funding mechanisms, and regulatory oversight.

We generally agree with the conclusions presented by Tim Woolf of Synapse Economics at the October 22, 2025, Task Force meeting stating that this current period of expected load growth is a poor time to eliminate decoupling.[5] Utilities have two motivations to sell more energy:

1) Throughput Incentive: Between rate cases, utilities can increase revenue and their effective rate of return by growing sales. This throughput incentive is addressed by revenue decoupling, which adjusts rates up or down based on actual sales to keep revenues aligned with authorized levels.
2) Capital Bias: Increasing energy sales often requires additional investment in grid infrastructure, which expands the rate base. Because utilities earn a return on invested capital, they have a structural incentive to favor activities that drive load growth, including electrification. Unlike the throughput incentive, this capital bias is not mitigated by revenue decoupling.

In a period of sustained projected load growth, it is especially important that utility incentives do not favor load growth at the expense of energy efficiency. Even under revenue decoupling, utilities retain an incentive to promote electrification-driven load growth due to capital bias. To manage system costs and maintain affordability, utility incentives should encourage prudent load growth, not unmanaged load growth.

[4] https://ma-eeac.org/wp-content/uploads/EEAC-Fixed-Charge-Heat-Pump-Rate-04162025-Dawson-Giovanniello-1.pdf
[5] https://www.mass.gov/doc/topic-4-decoupling-and-capital-recovery-expert-presentations/download#page=5.

Revenue recoupling could further strengthen utilities' motivation to increase load through electrification, but it would also introduce a disincentive to pursue complementary efficiency and conservation measures that moderate load growth and reduce customer bills. For example, a re-coupled utility may have a financial incentive to promote electric heat pump installations, but little incentive to support weatherization measures such as insulation or air sealing which reduce the energy required to operate those systems or allow for smaller equipment sizing. Likewise, a recoupled utility would be less motivated to offer programs that promote high-quality, right-sized heat pump installations, since inefficient or oversized systems produce greater load growth. Given ongoing uncertainty around load growth trajectories and rate impacts, aligning utility incentives with efficient, cost-conscious management of load growth is more critical than ever.

One alternative to full revenue decoupling that the DOER should analyze further is a lost revenue adjustment mechanism ("LRAM"). LRAM is a mechanism that allows utilities to recover revenue specifically lost due to defined factors or programs, including energy efficiency programs or weather-related impacts. Compared to full revenue decoupling, LRAM is intended to be a more targeted tool to align utility financial interests with achieving public policy objectives, such as energy efficiency. In practices, however, state experience LRAM has revealed several shortcomings:

1) LRAM policies are administratively burdensome, requiring utilities to calculate and reconcile every dollar of revenue allegedly lost due to energy efficiency programs.
2) LRAM policies create asymmetric risk that favors utilities over ratepayers. While utilities are permitted to recover revenues lost from reduced sales volumes, LRAM generally does not require utilities to refund customers in cases of overcollection. Therefore, LRAM functions as a backstop for utility revenues without providing comparable protections for customers.
3) LRAM does not fully remove the throughput incentive. An analysis of state experiences with LRAM conducted by ACEEE reveals that these policies are not associated with higher levels of energy efficiency spending or greater energy savings compared with states without LRAM policies.[6] Moreover, LRAM also does not remove a utility's incentive to increase sales to grow profits, undermining its effectiveness in supporting prudent, rather than unmanaged, load growth.

Before recommending that the D.P.U. eliminates decoupling, it's critical for the DOER to clearly identify the specific problem that this change is intended to solve, to evaluate alternative rate mechanisms that could address that specified problem, and to choose the appropriate options that are narrowly targeted and avoid creating adverse incentives that are counterproductive to other important public policy goals. Currently, there is not enough evidence to conclude that ending decoupling is necessary for incentivizing utilities to support load growth and reducing risk to customers. Rewiring America recommends that the DOER conduct further studies to assess the impacts of ending decoupling, including potential negative interactions with other rate mechanisms and the implications for low-income discount rates and existing customer

[6] https://www.aceee.org/research-report/u1503

protections, as well as the potential risk of incentivizing non-optimal load growth that will put additional strain on the grid.

Regulatory Sandbox

Rewiring America supports DOER's recommendation to explore a regulatory sandbox approach as a way to rapidly test, validate, and scale new products and services. Connecticut's Innovative Energy Solutions ("IES") Program offers a useful model, allowing third parties to propose limited, time-bound pilots with modest budgets. The IES model facilitates experimentation while ensuring consumer protections remain. A multistakeholder evaluation team scores proposals, monitors progress, and advances or retires pilots at defined checkpoints. Through establishing the success criteria upfront and clear pathways to scale, the IES Program provides commercial certainty for implementers and avoids leaving promising projects stranded in "pilot purgatory." Pilots funded through the regulatory sandbox could be further derisked with the inclusion of non-ratepayer funding such as tax revenue, green bank investment, or other mobilization of private capital, though it is critical to also establish safeguards are established to avoid improper influence of pilot selection or evaluation from outside funders.

Conclusion

Rewiring America is in support of many of the elements of DOER's Electric Rate Straw Proposal, including implementation of TOU rates, improving protections for low-income customers, and maintaining flexibility with rate design and regulatory mechanisms. However, we recommend that the TOU on-peak period be reduced to 4 hours, that low-income customers are offered shadow billing and extended rate switching options, and that the DOER conduct further evaluations of the impacts that may result from both ending revenue decoupling and including reconciliation mechanisms in base rates before implementing either measure. Incorporating Rewiring America's recommendations into the DOER Straw Proposal will ensure that the new electric rates have the greatest potential for positive impacts on the grid while minimizing any negative impacts that customers could experience as a result of implementing DOERs recommendations.

We greatly appreciate the DOER providing us with this opportunity to respond to the Electric Rate Straw Proposal, and for their continued efforts to advance affordability, equity, and efficient electrification for the Commonwealth.

Thank you,

/s/ Erin Mettler
Rewiring America
Regulatory Policy Associate
erin@rewiringamerica.org

SOLAR ENERGY INDUSTRIES ASSOCIATION'S COMMENTS ON MASSACHUSETTS DEPARTMENT OF ENERGY RESOURCES RATEMAKING STRAW PROPOSAL

I. INTRODUCTION

The Solar Energy Industries Association ("SEIA") welcomes the opportunity to provide comments on the Ratemaking Straw Proposal prepared by the Massachusetts Department of Energy Resources ("DOER") as a result of the work of the Massachusetts Electric Rate Task Force ("Task Force"). The Task Force built upon the efforts of the Massachusetts Interagency Rates Working Group ("Working Group") that was formed to advance near- and long-term electric rate design and ratemaking that aligns with the Commonwealth's decarbonization mandates. SEIA was a participant in both the Task Force and Working Group process, and, for the most part endorses, or does not object to, the proposals advanced by the Straw Proposal. That said, for the reasons detailed below, SEIA submits that the Straw Proposal should be modified in the following manner:

- With respect to the proposed increase to the fixed charge the Straw Proposal should be modified to:
    - Eliminate the Energy Efficiency Reconciliation Factor from the calculation of the fixed charge.
    - If the Straw Proposal continues to advance a significant increase to the fixed charge, the proposal should be modified to:
        - Incorporate the concept of gradualism; and
        - Place clear parameters around the costs that can be included in a fixed charge.
- With respect to the implementation of residential Time-of-Use ("TOU") Rates, the Straw Proposal should be modified to:
    - Offer recommendations regarding a peak-to-off-peak ratio, or at a minimum suggest objectives for setting the ratio;
    - Make clear that all residential customers will be afforded the opportunity to opt out of TOU rates;

- Recommend shadow billing for all customers;
- Recommend that the implementation of default residential TOU rates be delayed until customers can be presented with a consolidated TOU peak period across supply, distribution, and transmission; and
- Modify the time period afforded to the Electric Distribution Companies ("EDCs") for their marketing, education and outreach programs regarding TOU rates.

- With respect to the proposed reestablishment of marginal cost studies, the Straw Proposal should be modified:
  - Eliminate the recommended development of export tariffs.
- The Straw Proposal should be revised to recommend that, as the Department of Public Utilities ("DPU") advances in its investigation of rate design changes, the impact of those changes on programs designed to promote the development of clean, affordable energy should be considered.

II. Fixed Charge

Currently EDC customers are assessed a $10.00 fixed charge to cover customer access costs (e.g., meter, billing, service drop). The Straw Proposal recommends increasing this fixed charge to approximately $35.00 by converting the energy efficiency reconciliation factor ("EERF") and residential assistance adjustment factor ("RAAF") into fixed charges.[1] The primary justifications offered for this proposed increase, as found in the work of both the Working Group and Task Force, is that increased fixed charges would reduce volumetric rates, improving electrification affordability and overall cost-reflectiveness by shifting non-volumetric costs out of the volumetric rate. [2] As will be discussed below, it is far from clear that the objectives of improving electrification affordability will be served through the proposed fixed charge increase, while the negative impact on the distributed energy resource market could be significant. The combination of both factors – no real impact on electrification affordability and a reduction in the installation of distributed energy resources - will make it harder for the state to reach its carbon reduction goals. Moreover, the assertion that the EERF costs do not vary with usage is questionable. Given these circumstances, SEIA submits that the proposed increase to the fixed charge

[1] Straw Proposal, Slide 28.

[2] *Near-Term Rate Design to Align with the Commonwealth's Decarbonization Goals* (December 2024), p. 14 available at https://www.mass.gov/doc/irwg-near-term-rate-strategy-report-e3/download; Alternative Rate Design Expert Presentation Series | June 9, 2025, *Policy Fixed Charge*, Slide 11 available at https://www.mass.gov/doc/topic-2-alternative-rate-designs-expert-presentations/download

should be modified, limited solely to the inclusion of the RAAF costs. By doing such the goal of overall cost reflectiveness will be met, while there will be no significant negative repercussions on the Commonwealth's efforts to reach its goal of net zero emissions by 2050.

At minimum, if the Straw Proposal continues to advance a significant increase to the fixed charge, the proposal should be modified to incorporate the concept of gradualism as well as to place clear parameters around the costs that can be included in a fixed charge.

A. High Fixed Charge Does Not Meet Stated Objectives

1. Electrification Affordability

SEIA questions whether the increase in the fixed charge will increase electrification affordability. Key to this discussion is the fact that the fixed charge does not result in a decrease in the utility's costs. It just effects a means to rearrange how those costs are collected. Thus, there will be winners and losers with an increased fixed charge – a point clearly recognized in the report on *Near-Term Rate Design to Align with the Commonwealth's Decarbonization Goals* – shifting costs into a fixed charge "can cause bill increases for non-electrifying customers with below average usage."[3] For example, as noted in that report *s*:

> To better illustrate the implications of increased fixed charges for low- and high-usage customers (without accounting for income graduation), Figure 29 highlights the change in electricity bills for a low-usage customer today (small, multifamily home in Western Massachusetts with natural gas heating and room AC) moving to a rate with a $30/month fixed charge, compared to $10/ month charge today. This customer would see an $11 increase in their monthly average bill with a higher fixed charge. By contrast, if this same household were to electrify, their average monthly electricity cost would decrease under the increased fixed charge design, from $351 to $333, due to the reduced volumetric rate enabled by the increased fixed charge.[4]

Thus, if the customer in the above example is unable to electrify, the increased fix charge does nothing to ameliorate the electricity affordability issue, rather it makes it worse. While the above example does note that electrification leads to an $18 a month bill savings, such limited savings does little to increase electrification affordability as it does not factor in the significant costs of whole home electrification.

---

[3] *Near-Term Rate Design to Align with the Commonwealth's Decarbonization Goals*, p. 73, available at https://www.mass.gov/doc/irwg-near-term-rate-strategy-report-e3/download

[4] *Id*., pp. 55-56.

The focus of both the Working Group and Task Force work vis-à-vis the use of fixed charges as a means to spur electrification is limited to the impact of those charge on the *operating* costs of electrification – i.e., the incremental *electric costs* to customers when they invest in clean electric appliances or vehicles. The reduction in *operating* costs should not be confused with reductions in *upfront costs* which are necessary to make electrification technologies accessible The bill savings that will be achieved by most customers will make only a small contribution to the large outlay of money that is necessary to fully (or even partially) electrify.

Indeed, Rewiring America, based on data provided by the Massachusetts Clean Energy Center's Residential Air-Source Heat Pump Program (November 2014 through March 2019) and Whole-Home Heat Pump Pilot (May 2019 through June 2021) found that the median total project cost across all installation types for the former was approximately $8,300 before incentives, while the median total project cost for the latter was around $18,300 before incentives.[5] An $18 a month bills savings will do little to overcome such upfront costs. While incentives from the Mass Save program will, of course, lower these upfront costs for those who qualify, these heat pumps still represent a significant investment for consumers. Moreover, DPU recently reduced the Mass Save budget for 2025-2027 by $500 million resulting in a 15% reduction in the electric residential program[6] and thereby a reduction in both "whole-home" and "partial-home" heat pump rebates.

The limited impacts that lowering utility rates or energy bills has on electrification is documented by the Center for American Progress and Rewiring America:

> Although these [electric] appliance upgrades make sense from a health perspective and will lower operating expenses for households—as discussed later in this report—the upfront capital cost of these efficient electric appliances is a deterrent for consumers at the point of purchase. This is especially true given that the time for appliance replacement often comes during an emergency—the result of a suddenly unworkable appliance. *The slow payback rate of lower energy bills can make it difficult to justify a higher upfront cost for many households, especially* for those without extra cash on hand. Since homeowners are not expected to be experts in or investors in what is best from a

[5] Rewiring America, Report: Upfront Costs of Electrification (March 1, 2024) available at https://www.rewiringamerica.org/research/home-electrification-cost-estimates

[6] See https://www.mass.gov/news/dpu-reduces-mass-save-plan-by-500-million-and-approves-proposals-to-reduce-residential-gas-bills

climate perspective, the choice to go all electric needs to be made the easiest and most affordable alternative for families looking to replace an old fossil fuel appliance.[7]

While SEIA supports electrification and believes that distributed energy resources will be critical to affordably manage both the system and consumer costs of doing so, it does not believe that the imposition of a fixed charge which results in some customers being winners and some losers on their electric bills is a realistic means of advancing that goal.

2. Impact on Rooftop Solar

The electricity system is currently responsible for about 19% of statewide emissions.[8] Distributed solar generation is an important element of decarbonizing electricity in the Commonwealth. A key finding of the *Massachusetts 2050 Decarbonization Roadmap* when addressing the question of "what are the impacts of greater deployment of behind the meter solar and flexible end uses" was that a very high level of deployment led to additional demand flexibility that will lower local electricity system upgrade costs and, specifically, very high rates of rooftop solar reduce the need for ground-mounted solar, that suffer from siting issues in the Commonwealth.[9] According to Wood Mackenzie, Massachusetts has deployed approximately 300-400 MW of solar per year for the past few years, with the vast majority being located on rooftops for residential or non-residential use.[10] Rooftop solar and storage will continue to be a necessary generation resource for the Commonwealth in order to meet energy demand growth, increase demand flexibility, and reach the Commonwealth's clean energy and emission reduction targets. Deploying rooftop solar requires consumers to make a decision to install that is, in full or in part, based on the value proposition of potential energy savings. High fixed charges can significantly impact the financial return of solar installations, extending the payback period and reducing the potential energy savings realized. In this regard, a fixed charge will significantly impair the ability of third party owners of residential installations operating under the SMART program to achieve

7 *To Decarbonize Households, America Needs Incentives for Electric Appliances,* Center for American Progress and Rewiring America (June 2021) (emphasis added) available at https://content.rewiringamerica.org/reports/appliance-rebates-plan.pdf

8 *Massachusetts 2050 Decarbonization Roadmap*, p. 55, available at https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download

9 *Id*., p. 15, Table 1; *also*, p.59 (regarding siting of ground mounted facilities).

10 *U.S. Solar Market Insight Report Q4 2025 Data,* available at https://www.woodmac.com/industry/power-and-renewables/us-solar-market-insight/?utm_campaign=pandr-lenspr-g&utm_medium=social&utm_source=press-release&utm_content=SMI-Q4-press-release

the required 10 percent savings for customers,[11] thereby undermining a program objective to encourage the continued development of residential solar.[12]

The value proposition of rooftop solar and storage is impacted by many state and federal policies, including fixed charge rate design. The overall impact of a fixed charge on solar customers cannot be considered in a vacuum. The value proposition could be negatively impacted by three different proposals raised in the Straw Proposal: time-of-use rates, increased fixed charge, and potentially an export tariff. Additionally, during the roll-out of the Task Force recommendations solar customers will be impacted by the loss of the Residential Clean Energy Tax Credit and the Clean Electricity Investment Tax Credit as well as potential state policy changes to programs such as SMART or net metering. The cumulative impact of will discourage the deployment of distributed energy resources and concomitantly exacerbate the affordability issue.

One need only look at the generation capacity squeeze occurring in neighboring regional transmission operator, PJM Interconnection, to see the construct of increased demand and reduced supply manifest itself in higher electricity prices. Due to rising electricity demand without commensurate generation investment and deployment, PJM capacity prices have increased by a multiple of ten since the 2024 delivery year.[13] Indeed absent the price cap, the capacity price for the 2027-28 delivery year would have been over $500/MW-day.[14]

While ISO-NE has yet to experience this price surge, demand will continue to rise (as a result of electrification among other things), new natural gas generation is not coming online, and it is anticipated that IS0-NE's new accreditation process will reduce the amount of available supply.[15] Distributed energy resources can help meet the rising energy demand and alleviate the near-term pressure on capacity prices. The interplay of rate design changes such as elevated fixed charges and the pace of DER

---

11 *See* 225 Code of Massachusetts Regulations, Section 28.07(5)(a)1.

12 *Id.*, Section 28.01,

13 *See* Utility Dive (July 23, 2025), *PJM capacity prices set another record with 22% jump,* available at https://www.utilitydive.com/news/pjm-interconnection-capacity-auction-prices/753798/

14 2027 -2028 *Base Residual Auction Report* (December 17, 2025) available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf

15 ISO-NE is revamping its Capacity Resource Accreditation by moving to seasonal auctions (summer/winter) and shifting to a Marginal Reliability Impact framework. The new accreditation methodology will reduce the amount of capacity certain resources can offer into the market, even if their physical output remains unchanged.

deployment and the resulting impact on affordability should be front of mind as DOER finalizes it proposed recommendations for DPU.

3. Cost Reflectiveness

As noted above, the Working Group and Task Force reason that the proposed increase in the fixed charge allows for better alignment between customer rates and utility costs, as a share of utility costs do not scale with customer usage. However, such rationale simply does not apply to the EERF. The EERF enables the state's policy goal of meeting energy needs through cost-effective energy efficiency, electrification, and demand reduction resources. In other words, the resources paid for by the EERF are for the sole purpose of managing customer demand for energy and capacity. These demand-side programs are substitutes for wholesale generation and transmission resources.

B. Considerations for Implementation

1. Gradualism

While SEIA submits, for the reasons stated above, that the Straw Proposal should be modified to decrease the amount of costs subject to the fixed charge, should DOER proceed to advance the significantly elevated fixed charge proposal, the Straw Proposal should be modified to advance the phasing in of the proposed increased. Such modification is consistent with the rate design principle that changes to rate structure should be gradual. While Massachusetts already has a fixed charge, the Straw Proposal would move a considerable amount of costs currently collected through volumetric rates to such charge. The customer loses the ability to impact a significant portion of its electric bill through changes in their behavior. Customers should be afforded the opportunity to modify their behavior prior to being subjected to the full extent of the charge.

Gradualism in the implementation of an increased fixed charge is not without precedent. For example, such was employed by the Sacramento Municipal Utility District ("SMUD") when increasing its fixed charge from $7.20 to approximately $25.00 Specifically, the long-term plan for SMUD's residential fixed charge increase was approved by the SMUD Board in 2011. At that time the charge was $7.20 per month. The Board approved increasing the fixed charge to $10 per month in 2012, then raising it by $2 per month every year until it hit $20 per month in 2017.[16] Since reaching $20 per month, SMUD's fixed charge has been increased by the overall percentage rate increase, each time SMUD has raised rates, resulting in the current charge of approximately $26.00. The phased approach allowed for the increase in the fixed charge to be incorporated into electric bills without significant customer misunderstanding or pushback.

While gradualism does not dictate an elongated phase-in of the proposed increase in the fixed charge from $10.00 to $35.00, it does warrant, at minimum, a three year roll-in.

2. Fixed Charge Parameters

The focus of the Working Group and Task Force, as it involves a potential increase to the current fixed charge, is the transferring of "policy" costs from the volumetric portion of the rate to a fixed charge,[17] specifically focusing on the costs of the program for low income discounts and the energy efficiency programs effected through Mass Save.[18] SEIA agrees that the universe of costs eligible for fixed charge consideration should be confined to the narrow set of policy costs where the argument for fixed treatment is strongest, such as low-income assistance, rather than providing an open-ended pathway to continuously shift more and more costs into a fixed charge.[19] The Straw Proposal should be modified to reflect such limiting parameters.

III. TIME OF USE RATES

The Straw Proposal advances the adoption and implementation of a default TOU rate for all residential customers with a single, consolidated TOU peak period across supply, distribution, and transmission. The recommended peak period is between 3:00 p.m. and 8:00 p.m. non-holiday weekdays, with a differentiation in TOU rates between the summer (June - September) and winter (October -May) seasons.[20] SEIA supports DOER in its determination to advance the adoption of TOU rates for

---

16 *See* https://www.smud.org/-/media/Documents/Corporate/About-Us/Company-Information/Reports-and-Documents/GM-Reports/GM-Rate-Report-Addendum-2-06-16-11.ashx#:~:text=The%20General%20Manager's%20Report%20and%20Recommendation%20also%20proposes%20a%20restructuring,electric%20service%20to%20a%20customer at pp. 5-9.

17 Alternative Rate Design Expert Presentation Series | June 9, 2025, *Policy Fixed Charge*, Slides 5 and 10, available at https://www.mass.gov/doc/topic-2-alternative-rate-designs-expert-presentations/download; (December 2024), pp. 24-25.

18 *Id.*

19 The Straw Proposal recommends the elimination of, or the transition into base rates of, several reconciling mechanisms which are currently charged separately. *See* Straw Proposal, Slides 31 and 32.

20 Straw Proposal, Slides 13,16, and 18.

residential customers. Such rates can incentivize customers to optimize the use of renewable generation including solar paired with storage, to align with grid needs. However, there are several elements of the proposal that should be refined so as to ensure that the rates implemented invoke the desired ratepayer electricity consumption behavior changes.

A. Establishing a Peak-to-off-Peak Ratio

While the Straw Proposal contains a firm recommendation for defining the on-peak (3:00 p.m. - 8:00 p.m.) and off-peak (8:00 p.m.-3:00 p.m.) periods, it does not advance a proposal for the rate differential between those periods, despite the fact that this issue was explicitly addressed as part of the work of both the Working Group and Task Force. As discussed in the *Long-Term Ratemaking Recommendations*:

> An optimal peak to off-peak ratio is high enough to compel customers to shift their usage while also not being so high that the TOU rates become punitive, especially for those already faced with high energy burdens.[21]

Along those lines, building on the work done by E3 in the *Long-Term Ratemaking Report*, the Working Group noted that:

> The range of peak to off-peak ratios studied was from approximately 1.5:1 to 10:1, and the incremental response appears to diminish between a ratio of 4:1 to 6:1. *The Working Group recommends that the DPU further investigate the appropriate ratio, likely close to that range.*[22]

The issue of the appropriate peak to off peak differential was also part of expert presentations and targeted conversations of the Task Force.[23] It is unclear why this key component of any TOU rate would be omitted from the Straw Proposal. Any DPU determination on TOU rates must speak to the peak to off peak differential.

The reality is that the ability of any particular customer to respond to price signals afforded by TOU rates and shift load will vary based on individual circumstances. While *the Long Term Ratemaking Recommendations* spoke to an "optimal peak to off-peak ratio," DPU may want to consider

---

[21] Long Term Ratemaking Recommendation (March 2025), p. 21, available at https://www.mass.gov/doc/irwg-long-term-ratemaking-recommendations/download

[22] *Id*.

[23] Time of Use Rates Expert Presentation Series | May 19, 2025, *Presentation of the Maine Public Utilities Commission*, Slides 8 and 9, available at https://www.mass.gov/doc/topic-1-time-of-use-rate-design-expert-presentations/download; Time of Use Rates Targeted Conversation | May 28, 2025, Slide 20, available at https://www.mass.gov/doc/topic-1-time-of-use-rate-design-targeted-conversation/download.

whether a "menu" of TOU options with a range of differentials may best meet the needs of the Commonwealth. For example, as a way of introduction to TOU rates for customers who are unable to shift significant usage (or are unsure of their ability to do so), a rate option with a minimal differentiation between on and off peak could be offered. On the flip side, a TOU rate with a highly differentiated peak to off peak rate would provide customers who have the ability to shift load to use the off peak period to engage in such activities as charging their electric water heaters and running their heat pumps during times of significantly reduced rates. Such an opportunity can provide the savings necessary such that these customers would not face bill increases as a result of electrification.

The Straw Proposal should be modified to offer recommendations regarding a peak-to-off-peak ratio, or at a minimum suggest objectives for setting the ratio.

B. Opting Out of Default TOU Rates

The Straw Proposal calls for "automatically enroll[ing] all residential customers on TOU rates."[24] Accompanying this recommendation, DOER, in order to "minimize harm to low-income customers during a period of heightened concern for energy affordability," proposes "the DPU allow qualified low-income customers to opt-out of TOU rates."[25] The Straw Proposal provides no clarity as to whether all types of residential customers will be afforded the same right to opt out. SEIA submits that the recommendation in the Straw Proposal should be modified to provide opportunity to opt-out to all customers and that such opportunity should first occur prior to being "automatically enrolled."

To this end, in support of default enrollment, the Straw Proposal states that:

> Maine, Michigan, Long Island, and major utilities in California and Colorado, have or will be *implementing default opt-out* TOU rates.[26]

In other words, all customers taking service from the referenced utilities retained (or will retain) the right to opt out of the default TOU rate to another rate option offered by the utility.[27] This right is not reserved to low income customers. The same should be true in Massachusetts. Moreover, the customer's opportunity to opt out should not arise only after being placed on a TOU rate. Rather, as was

---

24 Straw Proposal, Slide 22.

25 *Id*., Slide 23.

26 *Id*., Slide 22 (emphasis added).

27 Implementation & Protections, Expert Presentation Series | July 21, 2025, *Reflections on California's TOU Transition,* Slide 6 ("TOU rates are voluntary and opt-outable."), available at https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download

done in California's successful implementation of default residential TOU rates, the onus should be placed on the utility to provide a minimum of two direct communications with the customer explaining the customer's options and making it clear if no action is taken then the customer will be defaulted onto the TOU rate.[28]

The inability to shift use to conform with TOU rates is not confined to low income customers. With the increasing concern over rate affordability, the right to determine which type of rate best meets a consumer's usage needs should be left to that consumer. As stated by the California Public Utilities Commission, while one of the goals of default TOU is to manage residential demand at high cost hours by having customers respond to price signal, it is also a priority to "provide customers with options and education so they can understand and choose which rate best suits their usage and lifestyle. This allows customers to opt out to a tiered rate if they cannot respond to TOU pricing or to be on a more complex or real time rate if the customer has the right in-home technology."[29] Massachusetts should take the same approach.

C. Shadow Billing

DOER recommends that shadow billing be provided to all low-income customers for a period of one year following enrollment on TOU rates. The intended purpose is to help these customers determine whether opting out will reduce their energy burden.[30] As discussed above, all customers, not just low income, should be afforded the opportunity to opt out of TOU rates. Accordingly, all customers should be given the information necessary to determine whether being on TOU rates increases their energy burden. Also, it is not clear why "shadow billing" should be limited to one year. For example, in California, the investor owned utilities provide ongoing "shadow billing" via online portals or printed comparisons, showing what a customer would have paid under their prior rate.[31] It appears that the Massachusetts EDCs will have comparable abilities once they implement Advanced Metering

---

[28] *See e.g.,* California Public Utilities Commission Resolution E-4882: Pacific Gas and Electric Company's (PG&E) Marketing, Education and Outreach Plan on Residential Default Time of Use Rates (December 18, 2017), p. 45, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K486/201486740.PDF.

[29] California Public Utilities Commission Resolution E-4895: Southern California Edison Company's (SCE) Marketing, Education and Outreach Plan on Residential Default Time Of Use Rates (February 8, 2018), p. 33, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M210/K028/210028013.PDF

[30] Straw Proposal, Slide 23.

[31] Implementation & Protections, Expert Presentation Series | July 21, 2025, *Reflections on California's TOU Transition,* Slide 7, available at https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download

Infrastructure ("AMI").[32] Accordingly the Straw Proposal should be modified to recommend shadow billing for all residential customers.

D. Implementation

The Straw Proposal recommends that TOU rates be implemented in phases. Specifically, the recommendation is that various components of the electric rate will be made subject to TOU pricing at different times. First supply will become TOU based, then transmission, then distribution.[33] The result is that the customer will not become subject to the full consolidated TOU rate for several years after the transition begins. While SEIA recognizes that such "phasing" may be viewed as a means to acclimate customers to the TOU concept, it submits that it could equally, and more probably, result in customer confusion over, and thus frustration with, the new rate structure and a differential that does not incent a change to customer behavior.

The use of TOU rates effects a significant restructuring in the manner in which residential customers will be billed for their use of electricity. The implementation of such a billing construct will require significant customer education to foster customer understanding and acceptance. Such education, if successful, will result in each customer understanding the mechanics of the rate structure and how it will impact their individual circumstance. As illustrated below, however, DOER's recommendation to incorporate various elements of the rate into the TOU structure over a period of years presents multiple opportunities to undermine customer understanding and interferes with the customer's ability to discern how the TOU rate structure could impact their electric usage and bills.

First, while DOER contemplates that default Basic Service TOU rates will be available in February 2028, only approximately 40 percent of Massachusetts customers receive supply service from their EDC. Therefore, a February 2028 roll out of Basic Service TOU will leave 60 percent of customers unexposed to a TOU rate. The Straw Proposal, however, does not appear to give any consideration to the fact that these customers will not have exposure to TOU rates until 2029 or later (when the transmission and then distribution components become subject to the TOU structure) in its proposed recommendations for the EDCs' marketing education and outreach program. While DOER recommends that the EDCs' initiate those programs 90 days prior to implementation, no indication is given to

[32] *Id.*, *Eversource MA AMI Implementation,* Slide 5.

[33] Straw Proposal, Slide 21.

whether the EDCs have to engage in comparable campaigns each time a new element of rate falls under the TOU rubric.

Second, the manner in which DOER is recommending that TOU rates be rolled out will leave customers unable to determine the impact which TOU rates will have on their bills. Without having knowledge of what the final consolidated TOU rate will be, there will be no means to estimate the bill impact if the customer cannot or does not shift its load.

In this vein, it is unclear how this phased roll in of rate components into the TOU construct works with recommended shadow billing (whether for just low income customers or all customers). DOER recommends that such shadow billing be provided for a period of one year following enrollment. However, this one year period will be insufficient for the purpose of helping the customer determine whether opting out will help reduce their energy burden if the amount of their electric bill subject to TOU rates keeps increasing for several years.

The success of TOU rates will largely be dependent on customers' changes in behavior regarding electricity usage in their daily lives. Achieving that behavioral change will require robust education prior to and after the launch of TOU rates and a positive reinforcement mechanism (i.e. lower utility bills) that is easily accessible and understood by customers. SEIA submits that the most likely time for customers to begin to develop the behavioral changes, and solidify those habits, will be when the concept is new to customers and corresponds with the marketing, education, and outreach provided by the EDCs. It will be important that customers can see the benefits of shifting their usage in that first year after the launch, otherwise there is a real risk of customers deciding that shifting electricity usage is not worth the effort because the financial benefit is too minimal. A phased in TOU rate with muted price signals to start could generate customer apathy during this critical initial phase because any impact on bills will necessarily be small for most customers. This could result in customers disengaging even as more of the rates become time-differentiated and the savings potential increases.

Finally, the recommended phased implementation will leave customers in the state of flux for the foreseeable future. Not only will they be facing an ever increasing portion of their bill being subject to TOU pricing, but there is also a significant possibility that before that process is completed they will face other changes in the TOU construct. For example, DOER recognizes the need to design TOU rates in a manner that can readily adapt to changing system conditions.[34] Thus, there may be a need to

[34] Straw Proposal, Slide 19.

incrementally adjust peak period timing and season definitions to reflect cost drivers. DOER anticipates that such changes could be made without waiting for EDC rate cases.[35]

Effective implementation of default residential TOU rates in Massachusetts would be best achieved if it is delayed until customers can be presented with consolidated TOU peak period across supply, distribution, and transmission. Not only will it enhance customer understanding and acceptance of the rate but it will afford the EDCs the opportunity to leverage AMI data before the fact to protect customers. In this regard, SEIA notes that the Straw Proposal offers several ways that the EDC analysis of AMI data can be used to deflect negative repercussions of TOU rates.[36] However, given the fact that two of the three major EDCs will not implement AMI until the beginning of the 2028, a planned role out of the default Basic Service TOU in February 2028 assures that any such analysis is done after the fact – i.e., after the customer is on the TOU rate. Allowing time for such analysis is to occur prior to roll out will afford the EDCs the opportunity to identify load profiles which could lend to significantly higher bills under TOU rates and work with the customer to ameliorate the problem *prior* to such rates becoming effective.[37]

E. Marketing, Education and Outreach

The Straw Proposal would leave insufficient time for an adequate marketing, education and outreach ("ME&O") program. Customer understanding of TOU rates is the underpinning of whether they will be successful in achieving their overall objectives of shifting load, reducing peak and, thereby, reducing overall costs to ratepayers. The current projected timeline as presented in the Straw Proposal has the DPU completing its inquiry into TOU rates by mid-2027, with the EDCs to implement Basic Service TOU rates in February 2028. This leaves approximately 6 months for the EDCs to effect an ME&O campaign. While the Straw Proposal calls for the EDCs to plan for implementation and ME&O ahead of a DPU decision on rate designs, the reality is that marketing campaigns and educational materials cannot be finalized and actual customer outreach cannot begin until the DPU has made a final determination regarding the construct of TOU rates.

---

35 *Id.*

36 *Id.,* Slide 25.

37 Implementation & Protections, Expert Presentation Series | July 21, 2025, *Reflections on California's TOU Transition,* Slide 8 (California utilities used proactive outbound calls to customers forecasted to be "significant non-benefiters" (> $100/year increase)), available at https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download

As discussed above, an attempted implementation of Basic Service TOU rates in February 2028 may raise a whole host of problems for customer understanding and acceptance of TOU rates. These problems will only be amplified if the marketing education and outreach accompanying the roll out is insufficient. As an example, the Straw Proposal cites to California as an illustration of a successful implementation of default TOU rates. Such implementation, however, was preceded by a two to three year effort by the utilities to educate their customers on TOU rates, starting with a more general building of TOU awareness to an increasingly more individualized focus.[38] The need for a more fulsome ME&O plan than can be accomplished in the Straw Proposal's recommended 90 days is also reflected in the expert presentations made to the Task Force. For example, GridX, presenting on best practices for marketing and education and outreach across the United States associated with the implementation of TOU rates, advocated for a 15 month pre-launch period (commencing after regulatory approval). This pre-launch period affords the utility the time to engage in broad TOU rate awareness, as well as utilize available data to gain insight on various customer populations.[39] While DOER indicated that this more generalized education on TOU rates could be (or should be) occurring even now, the EDCs have not been provided sufficient direction on that front.[40] Absent guidance from the DPU on the activities in which they should be engaged to advance TOU rates, it is unclear what actions the EDCs will take to advance awareness of TOU rates among their customers. Moreover, it is not prudent for the EDCs to incur ME&O expenses without DPU direction on long-term rate design directives.

The bottom line is that to ensure a successful implementation of TOU rates, the DPU must allow a sufficient time for marketing, education and outreach to occur and it must provide the EDCs guidance around such ME&O campaigns. As noted above, SEIA believes that the Straw Proposal's phased implementation of TOU rates is not pragmatic and could negatively impact the success of such rates.

---

[38] *See. e.g*., California Public Utilities Commission Resolution E-4895, Southern California Edison Company's (SCE) Marketing, Education and Outreach Plan on Residential Default Time Of Use Rates (February 8, 2018), available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M210/K028/210028013.PDF

[39] Expert Presentations, Marketing, Education, and Outreach (August 4, 2025), *Marketing, Education & Outreach (ME&O) for Time Varying Rate Programs – Best Practices Across the U.S*., Slides 14-15, available at https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-expert-presentations/download

[40] Marketing, Education and Outreach (MEO) Targeted Conversation | August 13, 2025, Slide 18, available at https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-targeted-conversation/download

Awaiting until all components of the TOU rate could be offered at one time, would allow sufficient time for an effective ME&O campaign.

IV. Reinstitution of Marginal Cost Study Requirements

The Straw Proposal calls for the review and update of marginal cost study guidelines and a reinstitution of the marginal cost study requirements for EDCs in future base distribution rate cases. As a component of that recommendation, the Straw Proposal calls for the DPU to "direct EDCs to develop export tariff for grid-connected resources; marginal cost study should inform granular, temporal cost-based pricing of exports."[41] SEIA questions the genesis of the proposal for export tariffs. As illustrated below it was not part of the Working Group recommendations, nor were export tariffs sufficiently discussed as part of the work of the Task Force. As a result, the recommendation is ill-defined and ill-supported. SEIA recommends that the suggested development of export tariffs be removed from the Straw Proposal.

Reviewing the documentation which forms the basis for the Straw Proposal reveals that there is insufficient underpinnings for advancing the creation of export tariffs at this time. First, the report on *Long-Term Ratemaking Recommendations'* clearly recognizes that the development of export tariffs is a discussion to be had in the future – not now. Thus, the report states:

> Following the deployment of AMI and the default seasonal TOU rate, as well as an opt-in CPP rate, the Working Group recommends the DPU consider additional ways in which to reduce peak demand of customers through other types of advanced rate designs, such as those discussed below.[42]

Export Tariff are included in the Working Group's list of advanced rate design that the DPU should consider subsequent to AMI deployment and the implementation of TOU rates. There was no contemplation that this sort of exercise should be engaged in during the next few years.

The lack of Working Group guidance on export tariffs, and its determination that it was an issue to be tackled down the road, is reflected in the Task Forces' work. There was simply no focus on export tariffs. To the contrary there was negligible attention provided the topic, consisting, in total, of the following:

---

41 Straw Proposal, Slide 35.

42 *Long Term Ratemaking Recommendations* (March 2025), p.23, available at https://www.mass.gov/doc/irwg-long-term-ratemaking-recommendations/download

- At the May 19, 2025 Task Force meeting a presentation was offered on the usefulness of marginal costs in developing the distribution component of TOU rates. The last slide of that presentation provided a list of the types of ratemaking decisions that utilize marginal costs which included "Value stack (G, T, D) export rates."[43] There was no elaboration on this point, nor was there any discussion at the May 19th task force meeting.
- At the June 9, 2025 Task Force meeting, as part of a presentation on *Advanced Rate Design: Key Theory and Options,* there was a mention of the use of short-term and long-term marginal costs as part of the "Algorithm for Socially Efficient Price Signals."[44] Again, this mention was in the context of policy goals and rate design objectives and not in the context of any specific rate design or tariff.
- Finally, the September 17th Task Force Meeting provided an opportunity for a targeted conversation regarding the use of marginal costs in rate design.[45] However, that discussion was limited, raising high level concepts such as the use of marginal costs to promote "efficiency in grid use (imports/exports)." Task Force members did not discuss the creation of an export tariff for grid connected resources.

In sum, the Straw Proposal's recommendation that the EDCs be directed to create export tariffs is not in line with the recommendations of the Working Group. Moreover, there was negligible attention to this matter as part of the Task Force's work. Accordingly, SEIA recommends that the suggested development of export tariffs be removed from the Straw Proposal.

V. CONSIDERATION OF IMPACTS ON CLEAN ENERGY PROGRAMS

In advancing potential changes in rate design, the Task Force and the Working Group did not give explicit consideration to the impact of those changes on certain programs that are designed, to a certain degree, to ensure low income customers share in the benefits of in the clean energy transition. In particular, the Community Shared Solar adder within the SMART program is inextricably linked to rate

43 Time of Use Rates Expert Presentation Series | May 19, 2025, *Marginal Cost of Distribution Service and Use for Time of Use Delivery Rate Design,* Charles River Associates, available at https://www.mass.gov/doc/topic-2-alternative-rate-designs-expert-presentations/download

44 Alternative Rate Design Expert Presentation Series | June 9, 2025, *Advanced Rate Design: Key Theory and Options,* Regulatory Assistance Project, Slide 9, available at https://www.mass.gov/doc/topic-2-alternative-rate-designs-expert-presentations/download

45 Tools of Utility Regulation Targeted Conversation | September 17, 2025 *Allocated and Marginal Cost Studies*, Slide 12, available at https://www.mass.gov/doc/topic-2-tools-of-cost-of-service-regulation-targeted-conversation/download

design for both customers and project owners. Because the value of the bill credits is tied to basic service rates, a restructuring of the basic service rate into a TOU rate may impact the revenue stream which a shared solar facility will receive and thus have an impact on the economic feasibility to meet the bill credit requirements for low income customers. For instance, under SMART 3, a Community Shared Solar project must deliver a certain percentage of the bill credits generated to Low Income customers at a certain discount level (which varies by offtake pathway chosen), and the value of the bill credits generated is tied to the basic service rate. Any change in the basic service rate will impact a project's revenue and cost assumptions, even for existing projects. Determining how a time-variable basic service rate will affect SMART Community Shared Solar project owners and customers is critical to ensuring the continued success of that program.

Similarly, a significant increase in the fixed charge as advanced by the Straw Proposal will reduce the amount of usage which can be "offset" by customers in a community solar program through project subscription. This reduction, in turn, may increase how many customers a project needs to subscribe because a larger portion of a customer's bill will not be able to be offset by volumetric credits. This places increasing pressure on required subscription levels, which have already proved to be difficult given the low income customer requirements.

The Straw Proposal should be revised to recommend that, as the DPU advances in its investigation of rate design changes, the impact of those changes on programs designed to promote the development of clean, affordable energy, especially the SMART Program, should be considered.

.

TEC

The Energy Consortium, Inc.

12/19/2025 Submitted Via E-mail

Mr. Austin Dawson
Deputy Director of Energy Supply and Rates
MA Dept. of Energy Resources

RE: Comments on the Ratemaking Straw Proposal Released on November 24th, 2025

The Energy Consortium (TEC) appreciates the work of the Massachusetts Electric Rate Task Force (Task Force) and the opportunity to provide these comments on the Ratemaking Straw Proposal.

TEC is a non-profit association of commercial, industrial, institutional, and governmental large energy users in Massachusetts and has participated in state and regional energy regulatory matters for forty years. It advocates positions and sponsors joint actions that promote fair cost-based energy rates, diversified supplies, retail market competition, and reliable service for its member organizations, their employees and all Massachusetts ratepayers.

Interval Meter Data Settlement with ISO-NE

TEC reiterates its comments in the AMI Working Group proceeding[1] regarding the urgent need for all commercial customers to have the ability to receive supply products where energy and capacity are settled based on actual interval meter load data. TEC supports the findings and recommendation of the Straw Proposal that DPU convene a proceeding to resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tags.[2]

Commercial Rate-Making Must be Driven by Cost-Causation

The rate making process should be fair to all customers with cost causation as the basis for rate design.[3] Although there may be political pressure to shield residential ratepayers from distribution cost increases, the temptation to have commercial customers bear excess costs is counter-productive in the long run. An over-looked aspect of maintaining affordability is the need to maintain a healthy base of commercial customers.

The revenue requirement of a utility is allocated amongst customer classes and if one class shrinks, the others will end up assuming a greater share of the utility revenue requirement all else equal. If commercial customers who are exposed to global competition reduce operations or relocate out of Massachusetts due to high energy costs, then the remaining customers are worse off since they will end

[1] DPU 21-80/81, TEC Comments 6/18/2025 and 8/5/2025
[2] Straw Proposal, slides 45-48
[3] Id, Slide 15

up bearing the revenue requirements that were previously met by departing customers. A scenario with a shrinking commercial customer base would exacerbate affordability challenges for the residential class. The rate design and cost allocation steps in rate-making must have direct line of sight to cost causing activities and work to minimize cross subsidies among rate classes and on an intra-class basis. Cross subsidies are not sustainable in the long run and are likely to be counter-productive.

Statewide Time of Use (TOU) Periods

TEC generally supports consolidating system peak hours for distribution and transmission and has repeatedly made arguments in favor of this in base rate cases.[4,5]

Many commercial customers are sophisticated and can adapt behavior or invest capital to respond to price signals. A peak window that is short enough to be actionable and aligned with system needs, is critical to ensure that customer actions can help mitigate cost pressures on the local and regional grid infrastructure.

TEC also generally supports differentiating rates by season[6], but cautions that Eversource recently moved from seasonal pricing to flat pricing in its rate designs, reportedly driven by consumer feedback.[7] TEC recommends that any move towards seasonal pricing be phased in. TEC recommends adopting aspects of the approach adopted by PG&E in California approximately five years ago when it converted its commercial customers to the new TOU periods and seasons. The new rates, B-10, B-19, B-20, were opened to customers on an opt-in basis for approximately 18 months while customers were allowed to stay on the legacy rates (A-10, E-19, E-20) prior to the mandatory transfer. During this time period, customers had the ability to obtain "shadow bills" to understand how their rates would compare under the new designs. While the Straw Proposal recommends shadow billing for low-income customers[8], shadow billing can also be a very useful and informative tool for commercial customers.

Opt-in Rates for Highly Flexible Customers are an Important Tool

Many TEC members with highly flexible loads or storage have been able to take advantage of the coincident peak billing rate option for transmission that is available to large customers. Rates such as this should be preserved, despite low customer counts, because customers who opt-in have unique characteristics and are able to provide demand response that benefits the system as a whole. Moving towards a harmonized peak period for most customers should not be viewed as a one size fits all solution, since there are subsets of highly flexible customers where coincident peak billing is appropriate and provides benefits to other customers.

---

[4] DPU 23-150, Direct (pp.23-29) and Sur-Rebuttal (pp. 5-10) testimony of A. Nutter filed 3/29/2025 and 5/3/2025, respectively

[5] DPU 17-05, Direct testimony of J. Bride filed 4/28/2025 pp. 3-8.

[6] Straw Proposal, slide 17

[7] See DPU 22-22

[8] Straw Proposal, slide 24

Consolidation of Riders into Base Rates

The Straw Proposal recommends consolidating several adjustment charges into base rates. TEC strongly supports consolidation of adjustment charges that are clearly linked to the costs of providing distribution service. Examples of these charges include vegetation management; advanced metering infrastructure, electronic payment recovery, etc.

TEC does not support the roll-in to base rates of any adjustment charges that are driven by public policy mandates or to support public policy driven programs (e.g., solar programs or EV infrastructure spending). TEC's concerns are motivated by the need to ensure transparency. Public policy programs, however worthwhile, should be presented to customers in a way that makes their costs transparent. Transparency in rates could be lost if everything is rolled into base rates. Furthermore, rolling multiple public policy driven reconciling adjustment factors into base rates creates a risk of earning volatility for the distribution utility. Many reconciling factors have fluctuated by up to several tenths of cent year over year when they true-up for prior years.

Support for Elimination of Revenue Decoupling

The Straw Proposal supports the elimination of Revenue Decoupling.[9] If load growth materializes due to beneficial electrification, then revenue decoupling should no longer be necessary to ensure utility earnings stability. As a result, TEC is supportive of this change provided that load growth does become evident and can be forecast with some degree of accuracy.

TEC looks forward to participating in the pending DPU proceeding to investigate rate design issues and thanks the Task Force for producing a comprehensive report to inform the process.

Sincerely,

Mr. Bob Espindola, Chairman
The Energy Consortium

[9] Straw Proposal, slide 39

Dear Mr. Dawson:

Thank you for the opportunity to provide comments on the DOER Ratemaking Straw Proposal released November 24, 2025. I appreciate the thorough analysis and the Department's leadership in moving toward cost-reflective rates that support long-term electrification and system efficiency.

My comments focus on **(1) the potential impact of Time-of-Use (TOU) rates and increased fixed charges could have on solar customers — both ownership and PPA-based**, **(2) program alignment concerns, particularly with Connected Solutions**, **(3) transitional or protective options that DOER could consider to ensure a fair and equitable evolution of rate design consistent with the Commonwealth's solar development goals and (4) a request for substantiation of what the alternative rate design would for customers who opt-out of TOU rates.**

Under the proposed structure, I would expect many solar customers to opt out of the TOU rate structure, which would blunt its effectiveness.

1. Impacts of Lower Off-Peak Rates and Higher Fixed Charges on Residential Solar Customers

The Straw Proposal's illustrative TOU rate design — particularly the **substantially lower off-peak energy price during solar production hours and higher fixed customer charges** — poses significant challenges to existing and future Net Metering (NEM) customers.

While the Straw Proposal characterizes this impact as "moderate," the combined effect of:

- shifting grid costs into **non-bypassable fixed charges**,
- lowering daytime volumetric rates, and
- applying **value-based NEM crediting during low-value TOU periods**,

could result in a **material erosion of solar economics** for customers who invested in systems under the current rate structure.

A. Ownership customers

Thousands of Massachusetts households invested substantial capital in rooftop solar with the understanding that a consistent, volumetric rate structure would allow the system to produce meaningful bill savings over its 20–30-year lifespan. Reducing the value of daytime generation under TOU — when solar produces virtually all its output — undermines these expectations.

B. PPA and lease customers

The impact on PPA customers could be significant. In today's market, Massachusetts PPAs frequently start at:

- **$0.24–$0.32/kWh** (often capped at $0.32),
- with **annual escalators up to 3.59%**.

Under the Straw Proposal's example TOU rates, daytime off-peak energy is valued at approximately **$0.285/kWh**. This means:

- A customer paying $0.30–$0.32/kWh under a PPA will **lose money** on each solar kWh produced during off-peak hours from day one.
- With contractual escalators, PPA prices may continue to exceed off-peak period rates indefinitely.

This creates **systemic financial risk**, potential contractual disputes, and inequitable outcomes — especially because PPAs are disproportionately used by low-income or credit-limited customers.

C. Battery retrofits are not a realistic, universal mitigation

The suggestion that solar customers "can add batteries" to better capture TOU value does not reflect market or technical reality:

- Battery retrofits are **prohibited in many PPA and lease contracts**,
- Many existing inverter configurations cannot accept retrofit storage,
- Even where technically possible, retrofits cost $15,000–$30,000, beyond the reach of most households.

Therefore, batteries cannot reasonably be framed as a universal or equitable mitigation for declining solar export value.

D. The Commonwealth should not unintentionally penalize solar customers or incentivize solar customers to opt out of TOU rates.

Encouraging solar adoption is an explicit statewide policy goal. A rate design that **devalues solar exports and offsets**, without transitional protection for existing systems, risks discouraging future adoption and undermining customer confidence in the stability of Commonwealth solar policy.

2. Net Metering Under TOU: MA's Existing Value-Based Netting Already Creates Solar Risk

Massachusetts' current NEM methodology is **value-based**, not kWh-for-kWh. Exported solar generation produces **dollar-denominated credits based on the retail value at the time of export**. Under flat rates, this behaves similarly to energy netting — but under TOU, value-based netting becomes a vulnerability:

- Daytime exports will earn **low-value off-peak credits**,
- Evening consumption will be charged at **higher TOU peak rates**,
- Solar customers may face significant residual charges even when their monthly kWh production equals or exceeds consumption.

This is an intrinsic threat to the existing NEM design once TOU price differentials are introduced.

3. Optional Approaches DOER Could Consider to Protect Solar Customers (Present and Future)

I respectfully suggest DOER consider the following *optional* mitigation approaches, which have been used in other jurisdictions to support a smooth transition to TOU while maintaining solar value:

OPTION A — Monthly “kWh-first” Netting (Energy Netting Before Value)

Under this approach — used in earlier California programs and several municipal utilities — customer exports and imports are **first netted in kWh instead of dollars across the billing month**, and only the remainder is billed at the applicable TOU rate.

This allows:

- solar generation produced in low-value periods to **fully offset** TOU peak consumption,
- maintaining the economics anticipated when systems were purchased,
- while still exposing *net consumption* to TOU pricing.

Because Massachusetts already uses **value-based netting**, this option would actually be *more protective* of solar customers than the status quo under TOU.

Illustrative example:
If a customer exports 100 kWh at 2 PM and consumes 100 kWh at 7 PM:

- Under current MA value-based TOU netting → the customer incurs a **net charge**, because export credits are low-value and consumption costs high-value.
- Under monthly kWh-first netting → the net energy is **0 kWh**, resulting in no volumetric charge.

- Or the credits could be weighted to reflect the distribution of peak and off-peak net consumption that occurred in the billing period and asign that weighted value to the NEM credits.

This option preserves solar value without undermining TOU principles.

OPTION B — Blended-Value “Smoothing” for Solar Export Credits

Another transitional option is to apply a **weighted average export value** for solar customers, such as:

- 25% peak + 75% off-peak, or
- a seasonal average aligned with typical solar production patterns.

This “smoothing” approach:

- prevents abrupt devaluation of solar exports,
- reduces customer bill volatility during transition years,
- ensures that solar continues to produce predictable savings,
- and preserves investor and consumer confidence.

This mechanism is simpler to administer than kWh-first netting and can be limited to existing systems, if desired.

OPTION C — Grandfathering Existing Systems

Many states have opted to protect existing customers for a fixed period (e.g., 15–20 years) under the rate structure in place at interconnection. This approach prevents existing systems from becoming stranded investments and upholds the Commonwealth’s reputation for policy stability.

4. Misalignment Between Connected Solutions and the Proposed 5-Hour TOU Peak Window

Connected Solutions presently relies on 2 or **3-hour dispatch events**, typically designed to maximize coincident peak reduction. Under a 5-hour TOU peak window (3–8 PM), a typical 10 or 20 kWh battery cannot:

- fully satisfy a 3-hour CS event **and**
- provide meaningful load-shifting for the remaining 2 hours of the TOU peak.

This means customers cannot maximize both Connected Solutions payments and TOU savings unless they purchase larger batteries — which is unrealistic for most households and prohibited for many PPA customers.

As DOER correctly noted in the Clean Peak Standard context, **misaligned program windows create "mixed signals"** and reduce the effectiveness of both TOU and DER programs.

Possible solutions include:

- extending CS events to match the TOU window with lower hourly discharge,
- allowing proportional dispatch across the entire peak period,
- or designing a transitional CS event profile for the first several TOU years.

Aligning CS and TOU windows will provide clearer incentives and better system outcomes.

5. Requested substantiation of alternative rate structure under TOU proposal.

If there is to be an opt-in alternative rate structure, it would be helpful to evaluate that alongside the proposed TOU structure. Will the non-bypassable charges apply to all rate payers? Will the existing flat rate structure persist as the opt-in alternative? WIll there be separate charges for opting out?

6. Closing Recommendation

Time-of-Use rates offer meaningful system benefits, but their adoption must be accompanied by reasonable protections and transitional measures for solar customers who invested under the existing structure. Addressing the issues identified above will help ensure that:

- Massachusetts maintains strong consumer trust,
- the residential solar market remains healthy,
- PPA customers are not placed into negative-value contracts, and
- DER programs work in harmony rather than at cross-purposes.

Thank you again for the opportunity to comment. I would welcome further discussion on any of these points.

Sincerely,

Mike Hempstead
President and Co-owner
Valley Solar
4130-238-6462
Mike@valleysolar.solar

December 19, 2025

Vote Solar respectfully submits these comments in response to the Department of Energy Resources' Ratemaking Straw Proposal presented to the Massachusetts Electric Rate Task Force on November 24, 2025.

As a clean energy advocacy organization committed to ensuring that solar and clean energy remain affordable and accessible to all Massachusetts residents, we approach these comments with the fundamental principle that rate design must protect customers, particularly low-income households, renters, and those with limited ability to manage consumption, while advancing the Commonwealth's decarbonization objectives in the most equitable and cost effective manner possible.

We appreciate the opportunity to submit these comments and thank the Department of Energy Resources for its thoughtful approach to this process. The time and effort DOER has dedicated to engaging stakeholders and developing this proposal reflect the seriousness with which the Commonwealth is approaching the future of affordable and effective rate design.

Rate Design

We recognize DOER's interest in rethinking recovery of public benefit programs, and we appreciate the opportunity to share our perspective on converting volumetric charges such as the Energy Efficiency Reconciliation Factor and the Residential Assistance Adjustment Factor, into mandatory fixed charges. Some households face structural barriers to reducing consumption – particularly low-income customers in electrically heated buildings or tenants without control over major load –but we need to understand how targeted investments and tenant protections might address these challenges while preserving customers' ability to manage their bills. The ability of customers to reduce their contribution to system costs through efficiency and distributed generation is not a flaw to be corrected, but rather it is the intended outcome of decades of Massachusetts energy policy. We encourage DOER to consider how changes to this framework might affect the relationship between rates and the behaviors those rates are designed to encourage – namely, customer adoption of clean energy technologies and efficient load management practices.

Increasing fixed charges may reduce customers' ability to manage their bills through conservation, potentially affecting affordability and incentives for energy efficiency. A household using 400 kWh per month may see its bill increase, so that a household using 1,200 kWh per month can see its bill decrease. That is a policy choice with distributional consequences that deserves explicit acknowledgment and debate. While fixed charges may have a place within voluntary, electrification-supportive optional rates, we encourage DOER to consider whether applying higher fixed charges across the entire residential class would advance equitable decarbonization goals. Simplifying bills has value, but we encourage careful consideration of the price signals that drive efficient behavior. If this is something DOER has considered, additional information on this topic would be helpful to see in the petition to the DPU.

We recognize concerns about uneven contributions to public-benefit programs among customers with rooftop solar, more efficient buildings, or seasonal load patterns. Volumetric charges are a longstanding and intentional feature of Massachusetts' clean energy framework. Customers' ability to reduce their energy usage reflects the success of policies designed to enable energy efficiency and conservation, lower system costs, reduce emissions, and improve resilience. We encourage DOER to consider how shifting these charges into the fixed portion of the bill might be counter to these long-standing state policies.

More broadly, we note that rates ultimately determine what customers pay, and the Commonwealth would benefit from considering advancing affordability by examining how these changes affect different segments of the population. If the policy aim is to lower bills, clarity about which customers will benefit and which may face higher costs, and a transparent discussion of tradeoffs would be valuable. We would appreciate further explanation on how reducing the visibility of public benefits charges interacts with the goal of maintaining affordable and accessible clean energy.

Regulatory Mechanisms

We generally support efforts to streamline the growing number of reconciling mechanisms, and we are open to transitioning many of them into base distribution rates to improve transparency and predictability. Reducing the proliferation of riders and trackers has administrative benefits and can improve transparency about what customers are actually paying for. That said, simply collapsing charges into base rates does not meaningfully reduce customer costs. . Folding a reconciling mechanism into base rates does not reduce the underlying cost; it changes where that cost appears on the bill. If the objective is affordability, this is presentation, not substance. If the objective is reducing the number of separate rate proceedings and associated administrative burden, that is a legitimate goal worth stating directly. The distribution charge is where utilities earn their authorized return. Reconciling mechanisms, by contrast, are typically pass-throughs. Consolidating pass-through costs into the distribution charge could create confusion about what portion of that charge represents utility earnings versus pass-through recovery. This is a technical point, but it matters for regulatory transparency and for future rate case proceedings where cost allocation will be contested.

We are concerned with the proposal to eliminate revenue decoupling and allow utilities to recover revenues through increased load growth, and hope to learn more about DOER's reasoning for this proposal in the petition. We recognize that decoupling is a tool, and like any tool, its value depends on context. We believe the current context warrants careful consideration of how recoupling might affect ratepayers, and potentially, state climate goals. This is especially true as we grapple with utility projections of increased load and the need to carefully scrutinize how the policy reasoning to support or deter different types of load – specifically, the difference between beneficial electrification and large load customers like data centers.

We also encourage DOER not to conflate the shortcomings of Massachusetts' current multi-year rate plan (MYRP) design, particularly the stay-out provision and negative productivity factor, with the value of performance-based regulation or alternative regulation more broadly. A poorly designed MYRP does not mean PBR should be abandoned. Instead, the Commonwealth could correct design issues and retain tools that align utility incentives with affordability and system efficiency. For example, Massachusetts' MYRP design has a specific, identifiable issue: the productivity factor has operated as a negative value, meaning the inflation-minus-productivity formula has increased rather than constrained revenue growth over the stay-out period. By year five of a rate plan, utilities are recovering more than they would have under traditional cost-of-service regulation which is the opposite of PBR's intended effect. This is a design issue, not a conceptual one. We are interested to see how DOER is considering changes to the PBR or alternate regulatory model in the petition.

The risk in the current moment is that Massachusetts will abandon PBR mechanisms, return to something closer to traditional cost-of-service regulation, and then rediscover in five years why those mechanisms were adopted in the first place. We have seen this cycle in other jurisdictions. Breaking it requires careful diagnosis of what specifically has failed and why, rather than wholesale rejection of regulatory innovation. Any regulatory mechanism reforms should ensure that low-income customers are not exposed to higher bills or disproportionate risks as a result of structural changes intended to support decarbonization.

Process and Implementation

The process and implementation framework would benefit from more detail to ensure that customers do not face unintended financial or operational consequences as these reforms advance. Slide 4 in particular could be expanded to clarify the goals, sequencing, and customer protections associated with the recommended changes. For example, the straw proposal simultaneously recommends increasing fixed charges (which reduces price signals for consumption management) and implementing time-of-use rates (which can strengthen price signals for consumption timing). These are not necessarily contradictory, but the interaction deserves explanation. Similarly, the relationship between eliminating decoupling and eliminating capital trackers is not fully developed, but both affect utility revenue recovery between rate cases in different ways with different ratepayer implications. We encourage DOER to provide a more detailed explanation of the theory of change underlying these recommendations: what problem each proposal solves, what tradeoffs it creates, and how the package as a whole advances affordability, equity, and decarbonization simultaneously rather than trading one against another.

California's TOU transition offers useful lessons for Massachusetts. Several elements of California's approach merit consideration: phasing implementation by starting with customer segments already familiar with rate structures (such as NEM customers), conducting sustained marketing and education campaigns well in advance of default enrollment, providing opt-in opportunities before mandatory transition, and using shadow billing to help customers understand how their bills would change before changes take effect. We note that California's experience also illustrates considerations. Early TOU implementations in some service territories produced significant customer concerns, particularly among customers with limited ability to shift load. Massachusetts should learn from both California's successes and its challenges.

Conclusion

We close with observations about the overall direction of these proposals. The Healey-Driscoll Administration has made energy affordability a stated priority. The cumulative effect of these recommendations (higher fixed charges, elimination of decoupling, potential acceleration of capital spending) may point toward higher bills and reduced customer control over those bills. We encourage DOER to consider how this trajectory aligns with stated affordability priorities.

We recognize that decarbonization requires investment and that investment has costs. We are not arguing for freezing rates or blocking necessary infrastructure. We are suggesting that the allocation of costs and risks between utilities and ratepayers should be deliberate, transparent, and consistent with stated policy priorities. The current proposals may shift risk toward ratepayers, and we would like to see further explanation about the rationale for this allocation in the current environment.

We encourage DOER to continue developing the sequencing, communications strategy, and consumer protection measures to ensure that any rate or regulatory reforms strengthen affordability rather than inadvertently raising costs for the very customers the Commonwealth intends to support.

We thank DOER again for its leadership on these important issues and for creating space for meaningful stakeholder input. We look forward to continued engagement as this process advances to the Department of Public Utilities, and we remain committed to working collaboratively toward policies that expand access to affordable, reliable clean energy for all Massachusetts residents.

Respectfully submitted,

Lindsay Griffin, Northeast Regulatory Director