Long-Term Ratemaking Recommendations

Accompanying Recommendations to Long-Term Ratemaking Study

March 2025

Massachusetts Interagency Rates Working Group

A Collaboration to Advance Near- and Long- Term Rate Design and Ratemaking that Aligns with the Commonwealth's Decarbonization Goals

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Executive Summary

The **Interagency Rates Working Group (Working Group, or IRWG),** which includes representatives from the Executive Office of Energy & Environmental Affairs, the Department of Energy Resources, the Massachusetts Clean Energy Center, and the Attorney General's Office, was formed to advance near- and long-term electric rate design and ratemaking that aligns with the Commonwealth's decarbonization mandates.

The Working Group, supported by Energy & Environmental Economics, Inc., explored the future of ratemaking in Massachusetts in the context of the energy transition from fossil fuels to electrification. Electric ratemaking and rate design must prioritize affordability, such that residents do not experience unaffordable energy burdens, alongside goals to reduce barriers to transportation and building electrification. The objective of the **Long-Term Ratemaking Study** is to identify advanced rate designs and alternative regulatory mechanisms that better support the adoption of electrification in Massachusetts in the long-term. The Long-Term Ratemaking Study provided key support for the Working Group's examination of potential changes to electric rate design and ratemaking. While the focus of the Working Group is on rate designs for residential customers, several of the rate design recommendations contained herein are relevant to all customers. In addition, several recommendations related to ratemaking and regulatory consideration are applicable to all customers.

Summary of Recommendations

The Working Group prepared these recommendations following the development of the Long-Term Ratemaking Study and robust stakeholder engagement. The **Long-Term Ratemaking Recommendations** identify opportunities to leverage rate design, ratemaking, and regulatory mechanisms to cost-effectively achieve the Commonwealth's greenhouse gas (GHG) emission reduction mandates and mitigate unnecessary investment in the electric power system, with a focus on customer affordability. The Working Group acknowledges the complexity and interrelatedness of several of these topics and as further discussed, plans to convene key stakeholders to discuss potential issues to be included in a petition to the Massachusetts Department of Public Utilities (DPU). The Working Group anticipates that such a petition may address issues related to the following Working Group recommendations, including:

- The development of a default seasonal time-of-use (TOU) rate for residential customers of all electric distribution companies (EDCs), with critical bill protections, when advanced metering infrastructure (AMI) meters are deployed;
- The consideration of additional, more granular rate options, such as a residential critical peak pricing (CPP) rate on an opt-in basis;
- The proper development and implementation of marketing, education, and outreach (MEO) efforts, in addition to critical monitoring and evaluation to ensure equitable outcomes, associated with the roll-out of widespread time-varying rates (TVRs);
- The complementary policies and programs that will be impacted by changes in rate design, ratemaking, and regulatory mechanisms; and

- The development of a regulatory framework that advances a clean, equitable, electrified, and decarbonized energy future.

Introduction

The **Interagency Rates Working Group (Working Group, or IRWG)** was formed to advance near- and long-term electric rate design and ratemaking that aligns with the Commonwealth's decarbonization mandates. The Working Group includes representatives from the Executive Office of Energy & Environmental Affairs (EEA), the Department of Energy Resources (DOER), the Massachusetts Clean Energy Center (MassCEC), and the Attorney General's Office (AGO).

Goals and Objectives of the Working Group

The **Massachusetts Clean Energy and Climate Plan (CECP)**[1] identifies electrification as a core strategy to reduce greenhouse gas (GHG) emissions in the building and transportation sectors. The Commonwealth has identified existing electricity rates as a barrier to widespread electrification and achieving the Commonwealth's decarbonization mandates.[2] The **Massachusetts Commission on Clean Heat Final Report** provided several recommendations related to aligning rate design with the Commonwealth's decarbonization mandates, including both near- and longer-term actions to address "the operating costs barrier to adoption of clean heating technologies."[3] Namely, the Commission on Clean Heat recommended that EEA "pursue opportunities to defray electric operating cost increases in the near-term and incentivize the expanded adoption of heat pump technology, particularly for LMI [(low- and moderate-income)] households."[4] The Commission on Clean Heat identified additional research needed regarding rate design.[5] While this Working Group was not developed to address all of the Clean Heat recommendations directly, the recommendations inform the Working Group's objectives.

In addition to considering the CECP and the Commission on Clean Heat Final Report, the Working Group engaged with stakeholders throughout the development of the Near-Term Rates Strategy Report and the Long-Term Ratemaking Study and the accompanying recommendations, with the objective of gathering and understanding stakeholder perspectives.

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[1] Reference includes the *Massachusetts Clean Energy and Climate Plan for 2025 and 2030*, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030; and the *Massachusetts Clean Energy and Climate Plan for 2050*, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050.
[2] *Final Report of the Massachusetts Commission on Clean Heat* at 23-24.
[3] *Final Report of the Massachusetts Commission on Clean Heat* at 24.
[4] *Final Report of the Massachusetts Commission on Clean Heat* at 25.
[5] The Commission on Clean Heat recommended that "[the DPU] should initiate an evaluation of the current electricity structure and alternative rate design options to identify opportunities that can better align energy prices with the cost of service and equity goals." The Commission also recommends that the DPU's investigation include opportunities to redesign/restructure current rates and offerings to more accurately reflect the cost of service for clean heat technologies and approaches to minimize additional cost burdens on low-income customers. (*Final Report of the Massachusetts Commission on Clean Heat*, November 30, 2022 at 24-26, https://www.mass.gov/doc/massachusetts-commission-on-clean-heat-final-report-november-30-2022/download).

The Working Group developed a project scope to examine the barriers and opportunities to support the clean energy transition through residential rate design and ratemaking. Widespread adoption of electric vehicles (EVs) and heat pumps are key to the Commonwealth's electrification goals. Because electric rates drive the operational costs of these technologies, electric rate design and ratemaking must prioritize affordability, such that no residents experience unaffordable energy burden (defined here as the percent of income spent on energy bills).[6] While the upfront costs to electrify also are significant barriers to adoption of EVs and heat pumps, and the Commonwealth must continue to pursue strategies to lower these upfront costs, especially for LMI customers, the recommendations discussed herein are limited to rate design and ratemaking. Similarly, while the rate design recommendations focus on residential rate design, the Commonwealth must also pursue strategies to reduce barriers to electrification for commercial & industrial customers, including through several of the strategies discussed herein regarding load management and sophisticated rate designs. With the support of Energy & Environmental Economics, Inc. (E3) and review, input, and insight from stakeholders, the Working Group developed three primary deliverables to support a set of recommendations of the Working Group, detailed in Figure 1.

Figure 1: Interagency Rates Working Group Deliverables

Electric Rates Asssement	Near-Term Rate Strategy Report	Long-Term Ratemaking Study
• Define the current state of electric rates in Massachusetts, describe the policy and regulatory landscape that shapes rates, and compare Massachusetts against other states' electric utilities	• Address operational cost barriers to near-term electrification through rate design offerings available before electric consumers receive AMI meters	• Present a vision and recommendations for advancing ratemaking mechanisms and rates for a decarbonized energy system and the associated technologies and capabilities available

[6] "Currently in the U.S. the affordability threshold is often set to 4-6% of income." Near-Term Rate Strategy Recommendations, Appendix: Defining Energy Affordability at 50 (citing Boardman, B., Fuel poverty: from cold homes to affordable warmth (1991)); *see* Near-Term Rate Strategy Recommendations, Appendix: Defining Energy Affordability, which includes a more comprehensive discussion of energy affordability and energy burden, https://www.mass.gov/doc/irwg-near-term-rate-strategy-recommendations/download.

Rate Design and Ratemaking Priorities

The Working Group developed the following rate design and ratemaking priorities, informed by several rounds of stakeholder feedback, discussed more fully below. These priorities draw from traditional rate design and ratemaking considerations, with additional focus on supporting the development of rates that avoid cost increases for electrifying customers, reduce peak demand, and align with the Commonwealth's climate goals and emission reduction mandates.

Figure 2: Near- and Long-Term Rate Design and Ratemaking Priorities

Promote electrification by removing operating barriers inherent in electric rates	• Design cost-based electric rates that encourage ratepayers to electrify end-uses • Create rate design features targeted to reducing energy burden for ratepayers - while maintaining safe and healthy living conditions
Increase adoption of cost-effective distributed energy resources (DER) to advance decarbonization and electrification	• Promote DER and equitably allocate costs (e.g., the costs of interconnection, incentive programs, etc.) through rate design
Integrate distribution system planning into the utility's business-as-usual operations and investments	• Promote least-cost electric system investments that accommodate transportation and building electrification and other new loads
Promote operational efficiency to facilitate the transition of the distribution grid	• Utilize price signals to achieve effective load management, including peak demand reduction, which may defer or avoid electric system investments • Improve grid reliability, efficiency, and resiliency

As an overall approach to maximize affordability, efficiency, and equity, electric rates should reflect the actual costs of the electric system. Cost-based rates send price signals that encourage consumption in ways that align with actual system costs, which vary throughout the day. Measures to reduce peak demand must play a critical role because peak demand drives the need for electric distribution companies (EDCs) to invest in grid infrastructure upgrades, the costs of which are passed to ratepayers. Appropriate and effective price signals incentivize customers to shift their usage off of high demand periods, decreasing strain on the grid, thereby reducing the need to invest in grid infrastructure, the costs of which are passed to ratepayers. In addition to rates, other peak demand management programs will also play a role; rates and programs should be viewed comprehensively as a package of tools to fairly reflect and recover system costs and provide price signals and opportunities to manage load and reduce costs.

Long-Term Ratemaking Study

MassCEC retained the services of E3 to support the Working Group. E3 conducted an analysis of long-term ratemaking and regulatory strategies to support electrification and energy affordability goals for electric ratepayers with advanced metering infrastructure (AMI).

The objective of the **Long-Term Ratemaking Study** is to identify residential rate designs that more accurately reflect the cost to serve customers and provide more efficient price signals, in addition to exploring the future of electric rate regulation and ratemaking to support decarbonization in Massachusetts.

The Massachusetts Workbook of Energy Modeling Results[7] demonstrates the required scale of decarbonization in the buildings, transportation, and electric power sectors to meet the state's GHG emissions mandates. The 2030 modeled targets consistent with sector limit GHG emission mandates include: 230,000 households with upgraded envelopes (i.e., a type of weatherization); 572,000 households with heat pumps; 1,000,000 light-duty EVs; and 3.2 gigawatts (GW) of offshore wind, 8.36 GW of solar, and 2.68 GW of energy storage.

Achieving these targets will require widespread adoption of electrified technologies, including by individual residents. Electric rates must be designed to support residents in their adoption of electrification technologies and associated usage patterns to ensure that the transition to clean energy does not result in unaffordable and unsustainable energy burdens.

Barriers to Electrification and Affordability with Existing Ratemaking

As presented in the Long-Term Ratemaking Study, the Working Group identifies the following key barriers to electrification and affordability inherent in current rate design and ratemaking. The Working Group's recommendations are focused on providing rate designs that will enable Massachusetts households to electrify end uses that support and advance the Commonwealth's climate and clean energy goals, as well as provide a framework by which EDCs are incentivized to support decarbonization cost-effectively.

Existing Electric Rates Do Not Provide the Proper Price Signals to Minimize System Costs

While the cost drivers of different levels of the electric power system are unique (i.e., generation, transmission, and distribution), additional investments are largely driven by system peak demand and in locations with substantial grid constraints.[8] Therefore, our existing electric rates, which are

[7] https://www.mass.gov/doc/massachusetts-workbook-of-energy-modeling-results/download.

[8] While electric grid investments are increasingly driven by localized grid constraints, these may be more effectively addressed through locational marginal pricing or non-rate design measures. Programs can be designed to address localized grid constraints. Although programs are briefly discussed in the Complementary Programs and Policies section, they are generally beyond the scope of these recommendations.

primarily volumetric (i.e., charged in $/kWh) and uniform throughout the day, fail to reflect the system cost drivers and thus do not incentivize customers to shift their consumption to times or locations where system costs are lower. Furthermore, existing rates do not reflect the long-term costs associated with increasing peak demand, some of which could be avoided by shifting certain loads off of peak hours. Cost-reflective rates can encourage customers to shift consumption to lower cost periods, which ultimately lowers electric rates, provided that forecasting includes appropriate assumptions about load management.

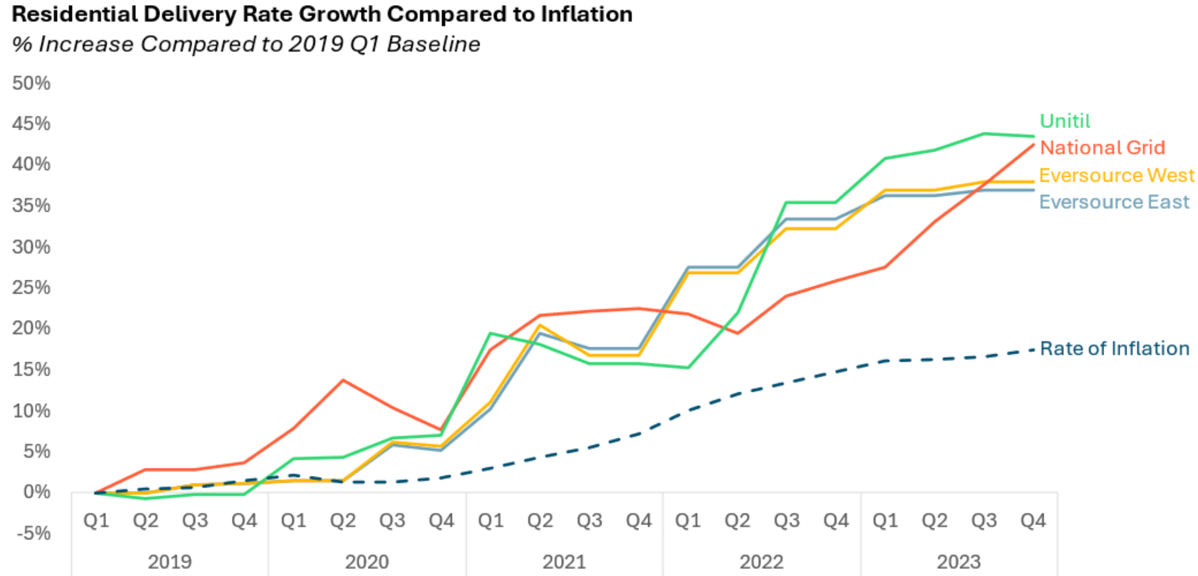
This misalignment between actual system costs and electric rate structures leads to higher peak demand, and therefore otherwise unnecessary investments in new grid infrastructure. Time-varying rates (TVRs), such as time-of-use (TOU) rates, can provide price signals that align with system costs. Well-designed rates will benefit ratepayers while simultaneously supporting the Commonwealth's clean energy goals.

Existing Electric Ratemaking Impedes Affordable Decarbonization

EDCs in Massachusetts play a critical role in achieving the state's ambitious decarbonization goals, including through the support of building and transportation electrification. Current electric rate designs and levels are an impediment to widespread adoption of heat pumps and EVs. Because the EDCs are regulated utilities, the electric rates that customers pay are an output of the regulatory framework in place. However, the existing utility regulatory framework in Massachusetts and the underlying incentive structures are not fully aligned with driving EDCs to efficiently and affordably achieve high levels of electrification.

Affordable electric rates are critical to minimizing the energy burden for Massachusetts residents and businesses, especially as we incentivize those consumers to electrify their heating and transportation demand. Existing high and increasing electric rate levels pose a barrier to Massachusetts' ability to achieve its electrification goals. Figure 3 demonstrates how electric delivery rates have outpaced the rate of inflation in a recent five-year period. This suggests that the current approach to ratemaking, if continued, will impede the Commonwealth's progress in achieving its GHG emissions reduction mandates and improving energy affordability for customers. A comprehensive regulatory framework that effectively balances and supports the Commonwealth's clean energy and climate goals will be necessary to advance a clean, electrified, and decarbonized energy future in a cost-effective manner.

Figure 3: EDC Delivery Rate Growth for Residential Customers, 2019-2023[9]



Stakeholder Engagement

Public outreach and engagement were critical inputs to the development of the underlying analysis and these recommendations. The Working Group conducted a robust stakeholder engagement strategy including through technical sessions, focus groups, and public listening sessions. Throughout the process, stakeholders have also had the opportunity to provide written comments. All written comments are available for public review on the Working Group website, and a summary of comments is available in the Appendix: Summary of Stakeholder Feedback.

The Working Group conducted the following stakeholder engagement events to support the development of this document:

Phase I: Framing and Scoping

The Working Group hosted a workshop to refine the scope of work on the Long-Term Ratemaking Study, soliciting input from stakeholders on the purpose and scope of the Study. After an initial general listening session, the Working Group also accepted written comment on the scope. The stakeholder engagement opportunity in this Phase was a presentation on the Long-Term Ratemaking Study on September 19, 2024.

Phase II: Long-Term Ratemaking Study Review

Following the development of the draft Long-Term Ratemaking Study, the Working Group hosted a series of workshops to present the results of the Study to stakeholders and solicit feedback. After

[9] Figure 3 was prepared by E3; residential delivery rate data accessed from the Massachusetts Electric Rates Database.

holding sector-specific workshops, the Working Group held a synthesis workshop to summarize comments for stakeholders and encourage cross-sector conversation. The Working Group carefully considered all feedback received from stakeholders and worked to meaningfully incorporate this feedback into the scope of the Long-Term Ratemaking Study and the Long-Term Ratemaking Recommendations.

Phase III: Equity Analysis

In response to feedback from stakeholders, the Working Group expanded the consulting expertise on the project to add an expert on energy affordability and energy justice. Dr. Destenie Nock of Carnegie Mellon University and Peoples Energy Analytics offered expertise in how energy usage patterns and energy affordability differ by demographics such as race and age, and for other vulnerable groups. Dr. Nock provided feedback directly to E3 on the Long-Term Ratemaking Study and on the Working Group's recommendations. In addition, Dr. Nock developed the Appendix: Long-Term Ratemaking Study Affordability Feedback that presents key considerations to ensure equity and affordability are centered in the development and implementation of TVRs and TOU rates.

Dr. Nock highlighted the following considerations for long-term rate design:

1. TVR price signals should be communicated in a way that is meaningful to customers, such as in terms of monthly bill impact;
2. The Commonwealth should ensure equitable access to the technologies that facilitate participation in load shifting;
3. Data-driven approaches should be used to monitor energy-limiting behavior in the summer and winter after TVR is implemented to identify impacts to affordability and enable the provision of targeted protections;
4. Non-shiftable loads (e.g., medical devices) or lack of access to load shifting enabling technology should be identified (this can be done with AMI data), and alternative rate structures that do not increase energy burden should be made available for those households.

These considerations supplement Dr. Nock's feedback and recommendations in response to the Near-Term Rates Strategy Report and Recommendations, which also speak to how AMI data can be used to advance energy equity.[10]

Recommendations

The Working Group prepared these long-term recommendations following the development of the Long-Term Ratemaking Study and robust stakeholder engagement. Previously, the Working Group's Near-Term Rate Strategy Recommendations released in December 2024 has resulted in DOER's petition to the DPU on advancing a seasonal heat pump rate for residential customers in the near-term.[11] The following recommendations address both **rate design** (including recommendations

[10] *See Near-Term Rate Strategy Recommendations* at 14 for a summary, in addition to the following appendices: Near-Term Rate Strategy Report Affordability Feedback and Defining Energy Affordability.
[11] *See* D.P.U. 25-08 Petition (2025).

related to AMI-enabled rates) and **regulatory and ratemaking mechanisms** that are critical to advance a clean, affordable, and decarbonized energy future.

The Working Group expects that an investigation at the DPU will be necessary to implement several of these recommendations. Even after robust stakeholder engagement discussed above and the benefit of external expertise from E3 and Peoples Energy Analytics, the Working Group determined that these topics could benefit from further stakeholder deliberations. The **Working Group recommends additional stakeholder discussion to facilitate further sharing of stakeholder concerns and positions, with the goal to build toward common understandings on areas of potential reform, such as those addressed in the Long-Term Ratemaking Study and these Long-Term Ratemaking Recommendations**. This stakeholder process is intended to include additional stakeholders that do not typically intervene in DPU dockets. DOER, on behalf of the Working Group, will convene a Massachusetts Electric Rates Task Force (Task Force), to support additional stakeholder discussions on rate design (including AMI-enabled rates) and regulatory and ratemaking mechanisms. The Working Group's analysis and the recommendations outlined below will serve to inform the Task Force's consideration of a regulatory framework that advances affordable decarbonization and electrification and that supports the DPU's implementation of its mandates to prioritize affordability, equity, and reductions in GHG emissions, in addition to safety and reliability of service.[12]

I. Rate Design

The Working Group explored TVR options that would provide more cost-reflective price signals and enable residential customers to lower their utility bills through managing the timing and volume of their electricity usage. Enabling residential load management, and peak demand reduction in particular,[13] will support least cost and affordable electrification and decarbonization. The Long-Term Ratemaking Study considered the following TVR options for residential customers: TOU, critical peak pricing (CPP), peak period demand charges, and real-time pricing (RTP).[14] These recommendations and the analyses conducted in the underlying Study are limited to residential customers. However, the Working Group notes the critical role that commercial and industrial (C&I) customers also will have in effectuating load management and peak demand reductions. The Study identifies that C&I customers contribute between 42 and 56 percent of peak demand, driving distribution investments that could be deferred or avoided through leveraging load management and peak demand reduction strategies.[15] In fact, large C&I customers are generally better equipped to take electric service under the more sophisticated rate designs often considered difficult to implement for residential customers. For example, the Working Group commends the DPU on its

[12] G.L. c. 25, § 1A; c. 164, § 141.
[13] Load management, and peak demand reduction in particular, can be enabled through both rates and programs. These Long-Term Ratemaking Recommendations focus on rates. However, the Working Group views complementary programs as necessary to appropriately incentivize load management, and instituting complementary rates and program will provide customers with a suite of options to manage their consumption and lower their bills.
[14] Long-Term Ratemaking Study at 21-24.
[15] Long-Term Ratemaking Study at 43-44, Table 2.

recent approvals of a coincident peak demand transmission charge for large C&I customers in Eversource and National Grid's service territories, which can accelerate the deployment of storage or reductions of load during peak times.[16]

Following detailed analysis and feedback from stakeholders, **the Working Group identified a default seasonal TOU rate in addition to an opt-in CPP rate as a pair of TVR options that can advance affordability and decarbonization**, as well as promote the rate design priorities identified in Figure 2. The two rates should be developed ahead of full AMI deployment and then implemented as AMI is deployed to customers. In the following sections, the Working Group provides further information regarding its recommended TVR and discusses protections for low-income or other vulnerable customers,[17] and the essential marketing, education, and outreach (MEO) that will be necessary during a transition to widespread TOU rates.

Deploy a Default Seasonal Residential TOU Rate

The Working Group recommends each EDC work to develop a seasonal TOU rate for residential customers that can be implemented when AMI meters are deployed. Designing and implementing a default seasonal TOU rate is a significant undertaking and requires significant customer education. The Working Group recommends that the Commonwealth utilize the period of time ahead of full AMI deployment (projected to occur between 2025 and 2029) to conduct the full investigation and education necessary to enable the availability of TOU rates when AMI is deployed.

A seasonal TOU rate provides a price signal that more accurately reflects the underlying costs of electricity delivery and supply compared to existing residential rates in Massachusetts. Exposure to these price signals will incentivize consumers to shift consumption to off-peak hours, which will reduce customer bills while also encouraging electricity usage patterns that reduce total system cost and therefore reduce long-term electric rates. **The Working Group further recommends that a TOU rate be default rather than opt-in, and that the rate include time-variation of both delivery and supply charges.** Each aspect of these recommendations, including seasonality, default, and that both delivery and supply be included, is discussed below.

In terms of seasonality, designing TOU rates to have peak and off-peak hours that dynamically reflect seasonal system load profiles offers even greater potential to shift peak demand and reduce grid constraints, emissions, and rates. For example, when the electric system is winter-peaking, peak rates that are higher in winter compared to the summer can reflect what is driving system investment and provide a stronger incentive to reduce usage in that season.

The Working Group considers a default (i.e., customers are automatically enrolled) structure a cost-effective strategy to enable the levels of load management necessary in a decarbonized future electric system. Compared to an opt-in rate, a default TOU rate can significantly increase

[16] D.P.U. 23-150 at 517 (2024); D.P.U. 23-150-B Order at 15-16 (2024); D.P.U. 22-22 at 461-462 (2022); D.P.U. 23-150, Attachment AG-4-8-1.

[17] Energy affordability is a challenge not only for low-income, but also for moderate-income customers, and Massachusetts's energy affordability efforts must reflect this reality. In the context of ratemaking, the Climate Act (St. 2024, c. 239) grants the DPU authority to investigate moderate-income discounts and promulgate regulations. These recommendations focus on the existing rate discount, which is specific to low-income customers; however, the discussion and recommendations may be applied to moderate-income customers.

enrollment.[18] Default TOU will therefore maximize the total electricity load that is exposed to price signals for load management. The Working Group notes that the DPU has supported a default TOU rate for basic service to maximize benefits to customers, including to low-income customers.[19] Customer protections related to the implementation of TOU rates are discussed further below. In addition, the Task Force will consider the tradeoffs of structuring it as default versus opt-in.

The Working Group, informed by stakeholder feedback, explored the following considerations, each discussed below: protections for low-income and environmental justice communities, TOU design for distribution and transmission charges, TOU design for supply charges, and principles for peak periods and price differentials.

Protections for Low-Income and Environmental Justice Communities

TOU rates introduce significant potential for cost-savings for residential customers who are able to shift their consumption. The evaluation of TVR in other jurisdictions provides evidence of potential benefits, including for low-income customers. In one instance, a majority of low-income customers experienced bill savings,[20] indicating that a categorical delay or even opt-in approach for low-income customers may be counter to the objectives of affordability and equity. However, Dr. Nock noted that this specific study did not investigate energy limiting behavior and thus was not able to identify whether bill reductions may have been due to reduced energy use caused by unaffordability perceptions. Further, there are some low-income or other vulnerable customers who may already be limiting their energy consumption because of costs or who have other energy needs which are not flexible. For these customers, shifting demand may be challenging. As a result, **the Working Group recommends that the DPU ensure that critical bill protections are in place to mitigate unintended harms from a default TOU rate. If appropriate, certain customers with limited load flexibility may need to be excluded from the default TOU rate to ensure vulnerable customers are not impacted by increasing energy costs.**

The Working Group considered several bill protection measures, including, but not limited to, shadow billing and bill stabilization. Shadow billing, the practice of calculating a customer's bill under both the existing (non-TOU) rate and the TOU rate, can be an important measure to demonstrate the bill impact of a TOU rate. Bill stabilization can be layered on top of this approach by ensuring that during a period of transition to a new rate, select customers will not pay more under the default TOU rate than they would have under the existing rate.[21] This ensures that these customers do not face increased costs relative to the non-TOU rate they were previously on, while preserving the incentive to shift behavior to realize potential savings associated with TVR.[22] The Working Group

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[18] Long-Term Ratemaking Study at 41-42.
[19] D.P.U. 14-04-C Order (2014).
[20] A PG&E TVR pilot found that 90% of low-income customers experienced savings under TVR, whereas only 6% were harmed. Opinion Dynamics (2020). *Assessing Equity in TOU: How Low-Income Customers Fare on Time of Use Rates*, https://opiniondynamics.com/wp-content/uploads/2021/06/2020_ACEEE-Summer-Study_Assessing-Equity-How-Low-Income-Customers-Fare-on-TOU_Rates_Folks.pdf.
[21] Long-Term Ratemaking Study at 42.
[22] Shadow billing has been demonstrated inside and outside of Massachusetts. The town of Groton in Massachusetts included shadow billing to educate customers in a TVR pilot that was found to successfully

recommends that bill stabilization be made available to at least all low-income customers during a transition period, such as 12 months, following the implementation of default seasonal TOU rates. Other potentially eligible customers include moderate- and fixed-income households, and households with inflexible loads such as medical devices. Shadow billing with bill stabilization will promote awareness of TOU rates and protect vulnerable customers from sudden bill increases. Further, it will provide the EDCs an opportunity to engage with customers and providers of low-income weatherization and fuel assistance programs to determine best practices in identifying certain customers, such as households with medical equipment or households exhibiting energy limiting behavior, that should be excluded from default TOU rates or enrolled in longer term bill stabilization programs. Depending on the impact of a default TOU rate on low-income and other vulnerable customers, protections, such as bill stabilization, may need to be available for longer than 12 months. Administering safeguards for vulnerable customers is a complex undertaking that needs to be further explored, and will be a topic of further discussion by the Task Force.

Residential Distribution and Transmission Default TOU Rates

Avoidable distribution and transmission costs represent the portion of system investment costs that can be deferred or avoided through shifting or reducing peak loads. Avoidable costs include, for example, local transformer and substation upgrades on the distribution side and line capacity increases on the transmission side.[23] Distribution and transmission costs are primarily driven by peak demand, which means that consumption during peak periods is higher cost compared to consumption during off-peak times. For these costs, TOU rates encourage shifting consumption off of periods in which additional demand necessitates grid upgrades, which are typically costly, thereby minimizing expenses on the distribution and transmission systems. The Long-Term Ratemaking Study demonstrates the value of applying TVR for distribution and transmission system costs to defer or avoid investments in additional grid infrastructure.[24] The Working Group notes that rates must be designed and implemented in a way that enables the EDCs to integrate peak demand reduction and load management expectations into their planning and forecasting. Without integration of load management projections into forecasting, utilities will plan and build for unmanaged load, negating the benefit of TVR to reduce costs by deferring and avoiding certain investments.

While the distribution and transmission systems may peak at different times, and further the distribution system may have localized peaks, the Working Group recommends the design of a default seasonal TOU rate with consolidated peak periods for distribution and transmission charges. The Working Group recommends that the DPU should direct the utilities to monitor the timing of

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shift customer usage and yield savings. National Grid currently administers shadow billing in a voluntary TOU rate for EV customers in New York, in which customers receive a reconciliation payment at the end of the year if they would have paid less under the flat rate.

[23] The Working Group notes that not all types of distribution and transmission investments can be deferred or avoided through shifting or reducing peak loads, particularly if load management is only motivated by a TOU rate standardized across the electric power system. Some avoidable costs, such as a local transformer, may depend rather on locational constraints or *customer* peak demand that is outside the *system* peak period. The section "Demand Response and Load Flexibility Programs Should Be Expanded" discusses non-rate options that may complement rate design in addressing these avoidable costs.

[24] Long-Term Ratemaking Study at 18-20.

transmission and distribution system peaks, as well as the timing of localized peaks, and report changes over time to determine whether this method remains reflective of investment cost drivers.

Although some granularity and precision will be lost, this approach of one consolidated peak will provide customers with simple and coherent price signals. From a consumer perspective, such a rate provides more transparency into cost drivers and empowers customers to reduce bills by aligning their consumption with the actual cost of service.

Residential distribution rates are primarily designed to recover utilities' costs that are allocated to residential customers. While a fixed customer charge ($/month) collects a portion of distribution costs (e.g., meter, customer service, etc.), a much larger portion of distribution costs are recovered through a volumetric charge ($/kWh).[25] While customer bills are primarily driven by total electricity consumption (measured in kWh), most distribution costs are caused by peak demand (kW) and allocated during rate proceedings based on measures of peak demand. Demand charges are fees based on the highest amount of electricity consumed by a customer during a specific time period, incentivizing the customer not to use power during peak periods. Though demand charges ($/kW) may be more cost-reflective than volumetric charges ($/kWh), stakeholders identified in public comments to the Working Group that demand charges are difficult for consumers to understand and introduce an intolerable level of bill uncertainty. A TOU rate with a time-varying delivery component represents a compromise: customers are exposed to a price signal to reduce consumption during periods that drive system cost, but the rate structure is predictable and easier to understand.

Residential transmission rates are currently designed as pass-through costs via a flat volumetric rate.[26] This inhibits the opportunity to provide customers with accurate price signals. TVR for transmission, as is the case for distribution, can encourage load management in a manner that would defer or avoid costly transmission investments and create long-term savings for ratepayers. The Long-Term Ratemaking Study notes the magnitude of transmission costs that may materialize as a consequence of failing to manage peak load growth, which are estimated to be between $7 and $10 billion in otherwise avoidable transmission expenses.[27] Massachusetts, in coordination with other New England states, is working on various efforts to reduce transmission costs, which fall outside the scope of this report. The Working Group notes that ISO New England (ISO-NE) – the organization responsible for overseeing the operation of New England's power grid – will be a critical stakeholder in the discussion of retail rate design to ensure a safe and reliable grid in an affordable manner. To provide customers with a cohesive price signal and promote a smooth transition to TVR, the transmission and distribution TOU rates should be coordinated – e.g., there is a single TOU period schedule that includes distribution and transmission costs, where the peak-to-off-peak cost ratio is

[25] As summarized in the Massachusetts Electric Rates Database, prepared by E3 for the IRWG, 95 percent or more of a customer's bill is based on a volumetric charge. The Electric Rates Database is available here: https://www.mass.gov/doc/massachusetts-residential-electricity-rates-database/download.

[26] Massachusetts EDCs charge transmission rates to customers based on the costs incurred to deliver electricity over high-voltage transmission lines, reconciled for actual costs. In other words, the utilities charge customers for actual costs incurred from transmission owners in delivering electricity.

[27] Long-Term Ratemaking Study at 19; ISO New England, 2050 Transmission Study (2024), https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

determined by the underlying avoidable distribution and transmission costs, as described earlier in this section.

The Working Group notes that because 85% of residential customers are served by either National Grid, Eversource (i.e., NSTAR Electric), or Unitil, time-varying the delivery component of rates will mean that the vast majority of customers will be served under a rate with a TOU component.[28] An improved, efficient price signal sent through time-varying delivery rates will be immediately applicable to and consistent across the majority of residential customers in the Commonwealth. Notably, in their proposed EV TOU rates for residential and small C&I customers, National Grid and Eversource differ on the most efficient method of time-varying distribution and transmission rate components; while both National Grid and Eversource propose to time-vary supply, National Grid proposes time-varying distribution to maximize price signaling abilities, while Eversource proposes time-varying transmission to complement non-rate load management programs. However, as outlined above and in the Long-Term Ratemaking Study, time-varying both distribution and transmission rate components maximizes the portion of a customer's rate that is time-varying, and therefore creates a stronger incentive to shift load. Electric supply rates vary substantially by customer because more than half of residential customers in Massachusetts procure supply through a variety of municipal aggregations or competitive suppliers. Recommendations related to time-varying supply rates are discussed in the section below.

Residential Supply Default TOU Rates

The Long-Term Ratemaking Study, in alignment with previous DPU investigations into TOU rates,[29] demonstrates that time-varied supply rates can reduce costs associated with electricity generation and promote the use of clean electricity. Supply costs reflect the price of generating electricity, which will increasingly vary based on time of day as more renewable generation is deployed. For supply, TOU rates can be designed to encourage consumption when electricity costs less, which may also be when renewable generation is abundant, thereby reducing capacity, emissions, and supporting the deployment of renewable energy.

Renewable energy resources produce electricity at lower marginal costs than fossil fuel generators, meaning that under a rate that time-varies the supply costs, the cheaper, off-peak hours often coincide with more renewable energy generation. In addition to unlocking savings for customers, a supply TOU therefore encourages loads to shift in alignment with renewables, reducing curtailment and maximizing the emissions reductions of renewable generation. Similarly, a supply TOU discourages consumption during peak periods, thereby avoiding the dispatch of fossil-fuel peaker plants, which generally have higher operating costs and higher emissions.

The Working Group does have concerns regarding the potential for misalignment of the peak periods of different bill components (e.g., distribution, transmission, and supply) and notes that this will need careful consideration by stakeholders, supply providers, and the DPU.

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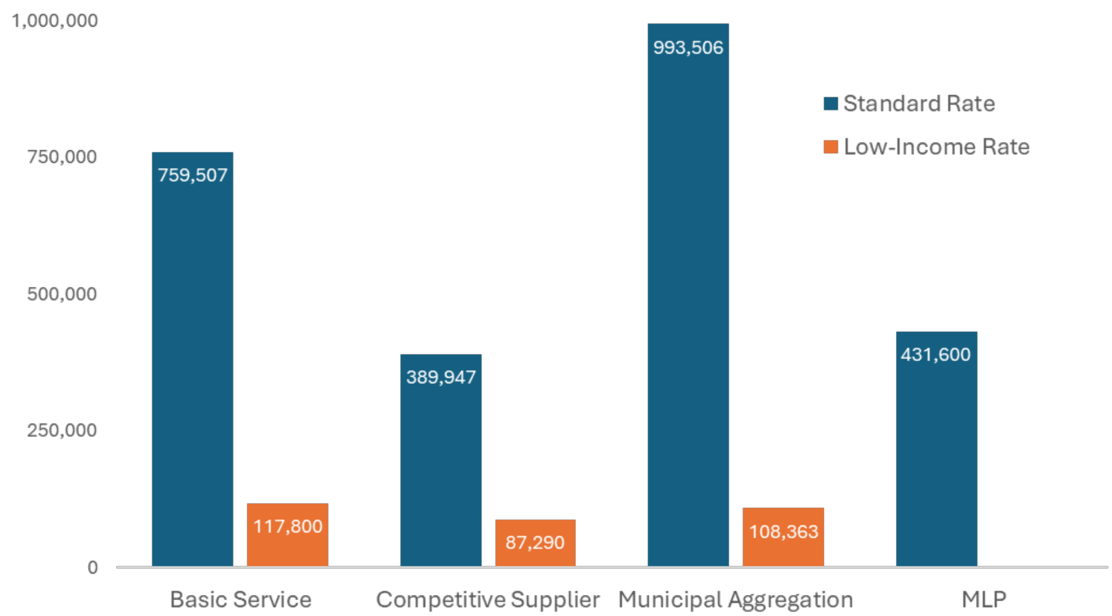
[28] Near-Term Rate Strategy Report at 20, Table 2. The remaining customers are served by municipal light plants (MLPs).
[29] D.P.U. 14-04 (2014).

Customers in Massachusetts can contract for the energy supply portion of their bill from three different contracting mechanisms: basic service, municipal aggregations, or competitive suppliers. As it relates to supply, the implementation of TOU rates will require tailored action and engagement that was outside the Working Group's scope. The Working Group supports the DPU's intention to investigate improvements to the accuracy and price signals sent to basic service customers.[30] Recent legislation requires data sharing that will provide municipal aggregators and competitive suppliers with the necessary information to develop and offer time-varying supply rates.[31]

The following subsections discuss important considerations for time-varying supply rates provided through basic service, municipal aggregation, and competitive supply.

Figure 4: Number of Residential Customers on Different Electricity Supplier Types[32]



[30] D.P.U. 23-50, Vote and Order Opening Investigation at 18-19 (2023).
[31] The 2024 Climate Act (St. 2024 c. 239) established G.L. c. 164, s. 116 requires the EDCs to establish a centralized data repository for AMI data – including billing and load data – to be available to suppliers and other third parties. G.L. c. 164, § 116C; St. 2024, c. 239, sections 79, 127, and 128. The AMI Stakeholder Working Group has also submitted a Final Report to the DPU outlining key data access issues relevant to municipal aggregations and suppliers. For more information, *see* https://www.mass.gov/info-details/grid-modernization-and-ami-resources#second-grid-modernization-plans-and-ami-implementation-plans-.
[32] Figure 4 represents the most recently available residential customer counts for all supplier types. Customer counts for basic service, competitive suppliers, and municipal aggregations are from June 2024 – *see DOER Electric & Gas Customer Choice Data*, https://www.mass.gov/info-details/electric-gas-customer-choice-data. The MLP customer count is from December 2023 – *see Near-Term Rate Strategy Report* at 20, Table 2.

Basic Service

Basic service offers the clearest path for regulators to approve a default TOU rate with a time-varying supply component. After the EDCs competitively procure power supply, the DPU reviews and approves the basic service rate. The DPU has previously signaled that it supports default supply TOU rates for basic service and will require the EDCs to implement them once the rollout of AMI is complete.[33] Moreover, the DPU intends to further investigate how "basic service… can be modified to improve the accuracy and price signals sent to basic service customers regarding the underlying cost of electricity."[34] The Working Group is encouraged by this effort; however, basic service only accounts for 35% of residential customers as of June 2024,[35] which means that advancing supply TOU rates through basic service alone will leave out most Massachusetts residents, limiting the potential customer savings opportunities and system benefits. Time-varying basic service and accompanying consumer education initiatives may, however, encourage municipal aggregations and competitive suppliers to offer their own TOU supply products.

Municipal Aggregations

As of June 2024, municipal aggregations procured energy supply on behalf of 46% of residential customers in Massachusetts.[36] The share of residential customers served by more than one-hundred municipal aggregations in the Commonwealth has grown rapidly in recent years, more than doubling from 21% in 2017.[37] Under a municipal aggregation, a local government negotiates a contract for energy supply on behalf of their constituents, typically with the help of a consultant. Municipal aggregations are responsive to the priorities of their customers, which often include savings and sustainability – priorities that are also advanced by TOU rates. Proliferating supply TOU rates among municipal aggregations will require additional engagement to communicate the benefits of supply TOU and generate support among local governments, their constituents, and the consultants who support them.

Municipal aggregations represent a unique opportunity to promote advanced supply rates. Given their growing share of the supply market, municipal aggregations are an essential part of the TOU future. Municipal aggregations may explore additional optional TVR offerings or pursue TVR designed to meet the needs or policy objectives of their communities. Enabled by the AMI data access requirement in statute, municipal aggregations may design supply TOU offerings that are specific to the use profiles and electrification levels of their constituents.[38]

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[33] D.P.U. 14-04-C Order (2014).
[34] D.P.U. 23-50, Vote and Order Opening Investigation at 18-19 (2023).
[35] For commercial and industrial (C&I) customers of all sizes, only 29% received their electricity supply from basic service, and those that did only accounted for 9% of all electricity consumed by C&I customers. *DOER Electric & Gas Customer Choice Data*, https://www.mass.gov/info-details/electric-gas-customer-choice-data.
[36] Id.
[37] Id.
[38] On July 9, 2024, the DPU adopted uniform guidelines for municipal aggregations that provide more discretion to municipalities while increasing transparency. While the DPU's decision did not explicitly address TVRs, the guidelines demonstrated the importance of a collaborative effort in accelerating emissions reductions. D.P.U. 23-67-A Order (2024).

Competitive Supply

Competitive suppliers are energy supply companies that offer direct contracts to individual customers. The AGO continues to find that Massachusetts residents are charged more for electricity supply from competitive supplier contracts compared to basic service as an alternative.[39] Furthermore, the AGO's analysis has demonstrated that competitive suppliers disproportionately enroll customers who live in low-income communities and charge these same customers disproportionately higher rates than customers living in wealthier communities.[40]

Although individual competitive suppliers could hypothetically design TVR rate offerings that could achieve some of the Working Group's goals, the industry's track record of consumer harm does not suggest a likelihood of success. The Working Group is concerned that competitive suppliers offering time-varying competitive supply rates will exacerbate the harms already apparent in the industry and members of the Working Group will continue to advocate for the elimination or significant reform of competitive retail supply offerings for residential customers.

Principles for Peak Periods and Price Differentials

To bolster the many benefits of TVRs, certain principles should be maintained to maximize the efficacy of TVR in driving electrification and decarbonization, while also ensuring affordable, equitable, and reliable electric service. The Working Group identified key principles for two specific TVR rate design components: peak period time segments and peak to off-peak ratios.

Peak Period Time Segments

The Long-Term Ratemaking Study discusses how peak, off-peak, and mid-peak time periods should be developed. While the Working Group acknowledges that the DPU has previously introduced the example of an eight-hour peak, from noon to 8 p.m., for a default TOU rate for basic service,[41] the Working Group recommends that the eight-hour peak period, as well as the specific time frame for the peak period, be evaluated consistent with the following principles:

- It is critical for peak periods to reflect actual peak period system costs. This ensures that the TOU rates provide clear and compelling price signals that encourage customers to shift their demand and therefore reduce further grid infrastructure investments. Additionally, by shifting peak usage, cost-reflective peak periods can reduce reliance on fossil fuel-powered peaker plants that are activated to support electric delivery during peak periods, thereby decreasing GHG emissions and supporting the integration of renewable generation.
- Peak periods should be sufficiently narrow to capture the most critical hours for reducing demand and make it easier for customers to most effectively shift their consumption by reducing the required behavior change to achieve meaningful peak shifting. Multiple

[39] Massachusetts AGO. *A Predatory and Broken Market: the 2025 Update*, https://www.mass.gov/doc/2025-ago-competitive-electric-supply-report-1152025/download.
[40] Id.
[41] D.P.U. 14-04-B Order at 8 (2014); D.P.U. 14-04-C (2014).

stakeholders identified that narrower peak periods are essential to maximize the load shifting benefits of TOU rates.[42]

- If appropriate based on distribution system peaks among customer classes for each EDC, consider consistent peak periods across the EDCs to minimize customer confusion. Stakeholders identified standardized peak periods as an important component in designing the most effective TOU rates.[43]

Peak to Off-Peak Price Differentials

The Long-Term Ratemaking Study provides evidence that forecasted peak load reductions increase as a function of the peak to off-peak ratio, but at a decreasing rate.[44] In other words, an ever-stronger price signal elicits a diminishing amount of response. The impact to peak of the identified peak to off-peak ratio across pilots studied was more significant for customers who had enabling technologies, such as smart thermostats, underscoring the importance of increasing the ability of customers to respond flexibly to price signals.[45]

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. However, some vulnerable populations, such as those using certain medical devices or those otherwise unable to shift usage, would be disproportionately burdened by large peak to off peak differentials. An overly high ratio also may drive so much load shifting that a new secondary peak is created, diminishing the initial benefits of the TOU rate.

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.[46]

Consider Opt-In Residential Critical Peak Pricing (CPP) Rate

The Working Group considered other rate options that could supplement a default seasonal TOU rate to maximize its price signaling ability and reduce grid stress. One such example of a supplemental tool is CPP, a rate structure with higher electricity prices during high-demand periods. High-demand periods (often referred to as “calls” or “critical events”) are typically called around 20 times a year, although utilities may be able to make CPP calls as often they deem necessary.[47] EDCs often make these CPP calls during summer heat waves or winter cold spells, creating an opportunity for customers to not only save on their bills, but also pre-cool or pre-heat their dwellings prior to CPP calls (sometimes using smart thermostats and similar technologies), and shift that load out of the

[42] *See* Appendix: Stakeholder Feedback Summary.
[43] Id.
[44] Long-Term Ratemaking Study at 40, Figure 15.
[45] Id.
[46] Long-Term Ratemaking Study at 40, Figure 15.
[47] *E.g.*, San Diego Gas & Electric Critical Peak Pricing, https://pubs.naruc.org/pub.cfm?id=5378C352-2354-D714-518C-BD97831D7C0E#:~:text=CPP%20events%20are%20most%20likely,from%20May%201%20to%20Sept.

CPP period.[48] When paired with a default seasonal TOU rate, CPPs provide an additional, complementary price signal to customers, providing a further tool to incentivize off-peak usage. The Long-Term Ratemaking Study notes that CPP rates have been shown to achieve the highest range of reductions compared to the other TVR alternatives.[49] This enhances the grid benefits offered by the TOU rate, while also creating opportunities for customers to receive lower bills.

Like TOU rates, CPPs are widely recognized tools for managing peak demand. Many stakeholders emphasized the value of CPP in making rates more cost-reflective, even if offered on an opt-in basis as a supplement to a TOU rate. An initial opt-in CPP rate, while potentially introducing new complexity, can allow customers to become familiar with CPP structures while maximizing the benefits already created by TOU rates. The Working Group recommends that each EDC work to develop an opt-in residential CPP rate as soon as practical so that the rate can be offered to customers as AMI meters are deployed.

Consider Further Advanced Rate Designs in the Longer Term

In addition to default seasonal TOU rates and opt-in CPP, the Working Group encourages the DPU to consider additional methods of reducing peak demand through rates, for residential customers as well as commercial & industrial customers, through advanced TVR designs, such as export tariffs, non-firm or limited import tariffs, day-ahead tariffs, and RTP. Load management programs will also play a role in reducing demand and should be evaluated comprehensively with rates.

Load management will become more essential as the Commonwealth, and the New England bulk power system, increases penetration of variable renewable energy. Promoting customer responsiveness, enabled through technologies and software, will be a central strategy to advance cost-effective decarbonization. Additional rate designs that may fit the individual or business needs of customers, while also reducing system peak, will be increasingly necessary. 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.

Export Tariffs

An export tariff allocates and recovers costs related to exporting energy onto the distribution grid in a manner that can incentivize efficient operation of distributed generation (DG) and distributed energy resource (DER), and in a manner that provides compensation consistent with grid benefits.[50] In addition, export tariffs can enable utilities to better integrate export into forecasting and planning processes. The Long-Term Ratemaking Study discusses symmetric price signals for import and export, and export tariffs are one approach to enable more symmetric and flexible pricing

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[48] Time-variant electricity pricing can save money and cut pollution, Environmental Defense Fund, https://www.edf.org/sites/default/files/time-variant_pricing_fact_sheet_-_april_2015.pdf.

[49] Long-Term Ratemaking Study at 39, Figure 14. CPP rates achieved up to a 60 percent reduction, whereas the other TVR designs analyzed (TOU, peak-time rebates, and variable peak pricing) reached a maximum of 40 percent reduction.

[50] *See* https://emp.lbl.gov/publications/distributed-energy-resource-der.

mechanisms that provide for better economic incentives for customers, such as incentivizing DER dispatch during peak hours, and discouraging export during times that cause costs, such as low-load events.[51] The implementation of an export tariff may necessitate consideration of current compensation programs and policies incentivizing DG, such as net metering and the Solar Massachusetts Renewable Target (SMART), discussed in the Complementary Programs and Policies section, to ensure that efficient bi-directional price signals (e.g., for import and export) are provided to DER customers and aggregators through allocation, recovery, and DER compensation approaches that provide incentives for grid benefits that they provide.

Opt-In Non-Firm or Limited Import Tariffs

While rates for non-firm service or rates with import limits[52] will provide more opportunities to reduce peak demand in the commercial & industrial context, there may be use cases for residential customers, namely for EV home charging. Opt-in non-firm or limited import tariffs can provide EDCs with operational flexibility and can thus be easily integrated in forecasting and planning. The EDC or an aggregator (at the request of an EDC) can dispatch reductions in load for participating customers, including during periods of localized grid constraints, through a separate meter or a submeter. The EDCs' operational flexibility can be facilitated through day-ahead scheduling or active management by the EDC.

Day-Ahead Tariffs

Day-ahead tariffs are rates based on the following day's expected electricity prices. This approach may be appropriate to further time-vary the supply component of a customer's rate. Under this rate structure, suppliers may notify customers in advance of the next day's electricity prices, thus allowing them to adjust their future consumption. Day-ahead tariffs encourage customers to shift their consumption to off-peak periods, while also encouraging DG developers to integrate their clean energy generation onto the grid during peak periods.

Real-Time Pricing

RTP is a rate structure that charges customers for *supply* costs based on electricity prices that fluctuate throughout the day. RTP can help manage peak demand by providing price signals to reduce usage during high-cost (i.e., high-peak) periods and may be appropriate for highly flexible customers, supported by automated technologies. The Long-Term Ratemaking Study identifies that RTP provides granular price signals that may lead to highly efficient customer response, but also exposes customers to high bill volatility.[53] On an opt-in basis, RTP may provide customers the greatest opportunity to respond to price signals and maximize system benefits.

[51] Long-Term Ratemaking Study at 38.
[52] This concept is similar to flexible connections for exporting facilities, where exporting facilities are under non-firm or limited export connection agreements.
[53] Long-Term Ratemaking Study at 24.

II. Marketing, Education, and Outreach

The effectiveness and success of any TVR design will depend on customer awareness, engagement, and responsiveness. The Working Group recommends the EDCs, in coordination with stakeholders and with guidance from the DPU, undertake MEO activities in a cost-effective, customer-centric manner. Stakeholders emphasized the importance of tailored materials, accessible web tools, personalized education, sufficient transition periods, and shadow billing as important features of an MEO plan. **The Working Group recommends the EDCs prepare an MEO plan, in coordination with stakeholders, including customers, to accompany the implementation of any TVR rate design approved by the DPU.**

The overall focus of the EDCs' MEO efforts should identify potential barriers to participation and then tailor MEO efforts to mitigate or remove those barriers to create an experience for customers that is as transparent, convenient, and frictionless as possible. While the specific approaches and goals of the EDCs' MEO efforts will vary for each specific rate, program, and initiative, and by location, in general, MEO efforts should be customer-centric and should:

- Minimize technical terms that can cause frustration and/or confusion to customers;
- Use plain-language terms that are simple and easy for customers to relate to and understand;
- Provide a single point of contact for all (or several) relevant rates/programs/initiatives;
- Reduce and simplify documentation and/or verification requirements;
- Ensure that customers can easily reach knowledgeable EDC staff with any questions (e.g., customer service representatives that answer calls or website inquiries should know the answer to questions or know how to get the answer to questions quickly);
- Recognize, prepare for, and respond to language needs for limited English proficiency customers;
- Tailor efforts to meet customers where they are (e.g., by providing the right information so that customers make informed choices);
- Use language that resonates with audiences of different cultural backgrounds (i.e., a multi-cultural communication strategy);
- Recognize that different communities will have different barriers to participation, different needs, and different motivations and may respond to messaging differently;
- Use a variety of outreach channels (e.g., email, phone, radio, internet, social media, and in-person events);
- Encourage collaboration and partnerships with community members and community groups, particularly from communities that are underrepresented in the clean energy transition and/or in the specific rate/program/initiative;
- Target individual households based on their needs and risks;

- Use meter (and eventually AMI) energy usage data along with available income data to identify the risk types that households face, and then communicate opportunities for electrification and reduction of financial burdens to these households;[54] and
- Use direct to household channels (e-mail, texting, in-app messages) to communicate about programs that benefit low-income households.

In designing MEO efforts, EDCs should draw from best practices, MEO professionals, and the experience of other utilities, including utilities in the Commonwealth as well as other jurisdictions.[55] To ensure that MEO efforts are effective, they should be evaluated regularly and revised as needed. This approach should include (1) message testing (qualitative and quantitative) before material is deployed; and (2) identifying and tracking key performance indicators.[56] Appropriate key performance indicators include:

- participation rates (including enrollment rates);
- penetration rates (i.e., the number of eligible customers who participate in a rate or program) at the census tract or block group level;
- bill savings;
- energy limiting behavior (i.e., households that under-consume energy during summer and winter months);
- customer satisfaction; and
- customer engagement level.

Given that smart technologies will be key for enabling customers to respond to TOU prices, penetration rates of smart devices should also be tracked, whether that is part of monitoring TOU rates, or as part of other incentive and deployment programs, such as Mass Save. The cost-effectiveness of implementing the EDCs' MEO efforts should also be tracked and evaluated (e.g., cost per leads, advertising response rates, etc.). This information should be shared publicly online in a format that is easy to find and understand, and not solely in utility filings.[57]

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[54] *See* Appendix: Near-Term Rate Strategy Report Affordability Feedback for the Interagency Rates Working Group for further discussion of energy use data informing targeted marketing.
[55] *See, e.g.,* American Council for an Energy-Efficient Economy, *Adapting Energy Efficiency Programs to Reach Underserved Residents* at 4 (Nov. 2023), https://www.aceee.org/sites/default/files/pdfs/adapting_energy_efficiency_programs_to_reach_underserved_residents_-_encrypt.pdf; Questline, *How to Reach Low-Income Customers of Energy Utilities*, https://www.questline.com/blog/how-to-reach-low-income-customers-of-energy-utilities/#:~:text=For%20energy%20utilities%2C%20building%20awareness,bill%20assistance%20and%20budget%20billing; Erifili Draklellis et al., *Five Steps for Utilities to Foster Authentic Community Engagement* (June 2, 2022) https://rmi.org/five-steps-for-utilities-to-foster-authentic-community-engagement/.
[56] This approach to evaluating MEO efforts may highlight barriers to participation that can be mitigated through changes to rate/program design. Thus, staff conducting tracking and evaluating MEO efforts should be in regular contact with rate/program administrators (PAs) to ensure that relevant information from MEO evaluation is used to inform program design.
[57] The DPU has examined procedural enhancements to its public notice requirements to increase public awareness of and participation in DPU proceedings and issued an Order Establishing Tiering and Outreach Policy (D.P.U. 21-50-A) on February 23, 2024, that should be informative to EDC filings and DPU approaches to outreach.

Given the novelty of TVRs for ratepayers in the Commonwealth, the EDCs should pursue opportunities to conduct targeted deployments of TVRs and related MEO campaigns during the next 4 to 5 years as AMI functionality becomes available in pockets of the state before the full-scale roll-out of AMI is complete. Smaller-scale, targeted deployments could be a helpful tool for testing and iterating effective rate designs, as well as the appropriate MEO approaches. It is critical, however, that these opportunities to test and learn do not delay the scaling of TVR and therefore delay customer benefits.

III. Monitoring and Evaluation

It is important to monitor and evaluate the performance of AMI-enabled rates to ensure that the design remains cost-reflective and to support the Commonwealth's clean energy and affordability goals, especially in the first few years following implementation of new rates.[58] AMI-enabled rates should be periodically reassessed and revised to respond to changes in energy load patterns, particularly as the Commonwealth and New England switch from a summer-peaking to a winter-peaking system. Regular reassessment will also be necessary to ensure that customers are adequately protected as new rate designs are implemented. AMI data will provide the EDCs with more accurate information to understand the changing behaviors and flexibility of demand under different conditions that can be used to reassess and revise TOU rates and other AMI-enabled rates.

Additionally, the energy consumption changes in low-income, minority, and other vulnerable groups should be tracked and monitored for impacts on energy burden and affordability. The deployment of AMI provides an opportunity to monitor energy burden and energy limiting behavior over time. AMI will allow for greater visibility into price responsiveness across income groups once TVRs are rolled out, to see if low-income households are negatively impacted by on-peak pricing (especially during extreme weather events when poor insulation, high heating or cooling load, and high on-peak rates would have a compounding effect). Additionally, the energy consumption changes in low-income, minority, and other vulnerable groups should be tracked and monitored for impacts on energy burden and affordability. AMI data should be used to protect customers and inform at-risk customers about bill assistance, energy efficiency rebates and incentives, including for accessing smart devices and enrolling in programs that enable customers to achieve savings by responding to price signals (e.g., for smart thermostats, EV charging, and other demand response programs discussed further below), and other measures that can improve affordability. Dr. Nock's Appendix: Long-Term Ratemaking Study Affordability Feedback includes further discussion on critical measures and indicators to monitor and evaluate as AMI data becomes available.

IV. Complementary Programs and Policies

While rate design is an important element of load management, the DPU and EDCs should also prioritize complementary programs that can incentivize similar behavioral changes. To meaningfully avoid certain distribution system investments, it will be necessary to design rates and programs in a coordinated fashion. By designing programs and rates as complementary to each other, the DPU can

[58] *See* Figure 2.

also ensure that diverse customers with different usage patterns and different degrees of flexibility have a range of options to manage consumption and lower their bills. Additionally, any proceeding focused on load management should identify the customers and technologies with the most potential for behavioral changes to maximize potential avoided distribution costs.

The following sections summarize existing or developing programs and policies that are essential complements as the Commonwealth decarbonizes and pursues load management.

Demand Response and Load Flexibility Programs Should Be Expanded

Demand response and load flexibility programming allows the EDCs to work with customers and aggregators to manage peak demand and create bill savings for all ratepayers. The Working Group expects that even when advanced rate design is enabled through AMI, there will be robust opportunities for demand response and load flexibility programs and policies that will complement well-designed TVRs by further incentivizing customers to shift energy use off of high-cost periods. For example, while rate design can provide more accurate price signals via temporally differentiating the cost of electricity, it may not be suited to address localized demand and responsiveness to grid constraints.

The Working Group also recognizes that dispatchable demand response and load flexibility programs, which can provide the EDCs with increased control over a customer's load and DERs, may be increasingly important to mitigate localized grid constraints. The existing demand response and load flexibility programs in the Commonwealth include Connected Solutions,[59] the Clean Peak Standard, and National Grid's EV Off-Peak Charging Rebate Program.[60] The Working Group recommends that demand response and load flexibility programs evolve and expand as TOU rates are deployed, and that the DPU also consider additional programs and policies that enable the EDCs to dispatch customer load and DERs.[61] Further, the EDC programs should utilize methods including marketing, education, engagement and incentives, to ensure that households, in particular low-income and other vulnerable households, have access to the devices and resources needed to take advantage of key enabling technologies for responding to the price signals communicated by TOU rates and load management programs. In addition to helping the EDCs access existing customer

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[59] ConnectedSolutions is a peak demand response incentive program for devices that can reduce electric use coincident with summer peak load, which as noted in the Near-Term Rate Strategy Report, may be critical in incentivizing reductions of coincident load during the winter peak as heat pump adoption increases. In 2023, Mass Save's ConnectedSolutions program successfully reduced approximately 76 MW of load in the residential sector and 73MW of load in the C&I sector. (https://ma-eeac.org/results-reporting/; https://www.masssave.com/en/residential/programs-and-services/connectedsolutions).

[60] Eversource and Unitil have proposed EV managed charging programs in the context of their requests for mid-term modifications to their existing EV Program in D.P.U. 24-195 and D.P.U. 24-197, respectively, filed in December 2024. National Grid has also proposed changes to its EV Off-Peak Charing Rebate Program in its request for mid-term modifications D.P.U. 24-196, also filed in December 2024.

[61] The development and commercialization of vehicle-to-everything (*i.e.*, V2X) technologies, such as bidirectional EV charging infrastructure, or electric vehicle supply equipment (EVSE) will also enable EVs to participate more readily as dispatchable demand resources. Eversource's proposal (D.P.U. 24-195) includes a request to implement a pilot program to provide an additional EVSE rebate to enable bidirectional charging equipment.

flexibility, such programs will incentivize customers to invest in grid-beneficial technologies, such as battery storage, that in turn will provide benefits to the distribution grid.[62]

The Working Group notes that MassCEC is leading a Grid Services Study, in collaboration with DOER, the AGO, and the EDCs, to determine the appropriate, effective level of compensation for DERs that can provide locationally – and time-specific flexibility services to the grid, and to better understand how DERs can provide services that help reduce the overall cost of the energy transition.[63]

Impacts on Distributed Generation and Energy Resources

The Commonwealth has supported DG and DER through several key ratepayer-funded initiatives, including the SMART program, net metering, and the Renewable Energy Portfolio Standard (RPS). The SMART program offers incentives for residential, commercial, and standalone deployment of solar in the Commonwealth, with bonus incentives for battery storage, community solar, and low-income participation. DOER is working with stakeholders to modernize the program and plans to release a new iteration of SMART in 2025. Net metering allows DG owners to receive credits at the retail rate on their electricity bills for exporting excess generated renewable energy to the distribution grid. Massachusetts also administers the RPS, which incentivizes renewable energy development by creating a demand for renewable energy certificates produced by renewable energy generation.

The transition from existing rate structures to TOU rates will impact the underlying incentives to install DG. The Commonwealth plans to closely engage with the DG industry during this transition to ensure the continued support of DG growth in Massachusetts. These changes to electric rates will also necessarily impact existing programs and policies supporting the adoption of DG and DER. For example, the Long-Term Ratemaking Study identifies the limited cost-reflectivity of DG incentives under flat rate structures and demonstrates the value to the grid from export tariffs discussed above that better incentivize solar and storage resources to operate in a manner that reduces grid stress. The Working Group expects the Task Force to further consider the impacts of specific rate design changes on customers who have adopted or will adopt DG and DER.

Upfront Incentives for Decarbonization Technologies

Mass Save provides rebates and financing to reduce the upfront cost of building energy efficiency and decarbonization solutions. Similarly, the Massachusetts Offers Rebates for Electric Vehicle (MOR-EV) program provides rebates and financing to reduce the upfront cost of EVs.[64] The Working Group recognizes that these are important programs to meet the Commonwealth's climate goals; however, additional funding sources are likely necessary, as discussed in Section V.

The Long-Term Ratemaking Study also highlights the important role of technologies that enable and automate load flexibility and demand response.[65] Incentive programs such as Mass Save should be

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[62] TVR can incentivize behind-the-meter battery storage investment and scheduled operation that reflects the underlying costs of the electric power system.
[63] *MassCEC's Grid Services Study*, https://www.masscec.com/grid-modernization-and-infrastructure-planning/grid-services-study.
[64] https://mor-ev.org/.
[65] *E.g.*, Long-Term Ratemaking Study, Figure 15.

leveraged to ensure that households, and particularly low-income and other vulnerable households, have access to the devices and education needed to take advantage of key enabling technologies.

V. Regulatory and Ratemaking Mechanisms

The Working Group explored several regulatory and ratemaking mechanisms that are critical components in the DPU's mandates to prioritize affordability, equity, and reductions in GHG emissions, in addition to safety and reliability of service.[66] The Working Group determined that these DPU mandates could benefit from further stakeholder deliberations prior to the DPU investigating a regulatory framework that addresses AMI-enabled rate design and ratemaking. As such, DOER will engage a body of key stakeholders, referred to as the Massachusetts Electric Rate Task Force (Task Force). **The Working Group expects the Task Force to further consider how rate designs and regulatory and ratemaking mechanisms can cost-effectively advance a clean, electrified, and decarbonized energy future. The Working Group's considerations outlined below will serve to inform the Task Force's discussion of a regulatory framework.**

Consider a Comprehensive Regulatory Framework that Effectively Supports the Commonwealth's Clean Energy and Climate Goals

The Commonwealth is at an inflection point in its energy transition. Significant load growth from electrification, necessary investments to modernize the electric grid, and AMI deployment later in the decade, requires reexamination of Massachusetts' existing regulatory framework. The regulatory environment should complement the Commonwealth's clean energy and climate goals driven by statutory requirements, while also encouraging the EDCs to develop innovative solutions to achieve those goals, particularly to support energy affordability, efficiency and flexibility of the grid, reliability of our electric system, and electrification of the building and transportation sectors. The Long-Term Ratemaking Study[67] and Appendix: Massachusetts Regulatory Framework Primer identifies regulatory and ratemaking strategies employed in Massachusetts that should be reassessed through the lens of decarbonization, electrification, and affordability.[68]

The existing regulatory framework is a tapestry of statutory requirements, regulations, and regulatory policy adopted by or advanced by the DPU.[69] This framework is modified by DPU orders, in response to legislation, changing operating environments, or changes to the DPU's priorities. Industry transformation and changes in law in Massachusetts have previously sparked a reevaluation of the regulatory framework. Now, additional changes are necessary to cost-effectively meet the Commonwealth's energy and climate goals.

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[66] G.L. c. 25, § 1A; c. 164, § 141.
[67] Long-Term Ratemaking Study at 51.
[68] While this Primer is not comprehensive, it discusses key features of Massachusetts regulatory framework, including cost-of-service (COS) regulation, revenue requirement, test years, and cost-of-service studies (COSS); revenue decoupling, reconciling mechanisms, capital cost recovery mechanisms, and distribution system planning; and components of performance-based regulation (PBR) such as formula-based rates or multi-year rate plans, earnings sharing mechanisms (ESMs), and performance metrics.
[69] G.L. c. 164, §§ 76, 94.

In 1994, the DPU oversaw a significant transition when the DPU investigated "the theory and implementation of incentive regulation" to establish a framework that included alternative regulatory approaches.[70] The investigation focused on whether alternative regulatory approaches could better accommodate the transition from monopoly to competition that was underway in the gas and electric industries, compared to the existing regulatory framework.[71] The DPU again revisited its ratemaking practices in 2008 to address the heightened and volatile costs of natural gas and electricity in the Commonwealth, and to examine rate structures that would promote efficient deployment of demand resources supported by the passage the Green Communities Act of 2008.[72]

Since 2008, the Massachusetts Legislature has passed several pieces of legislation that have changed the statutory requirements, and thereby the operating environment of the utilities, including amending the DPU's priorities. *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy,*[73] among other transformational changes, amended the DPU's priorities to include affordability, equity, and reductions in GHG emissions to meet limits and sub-limits established under law, in addition to its traditional role related to safety, security, and reliability of service.[74] In addition, *An Act Driving Clean Energy and Offshore Wind* (St. 2022, c. 179) established the Grid Modernization Advisory Council (GMAC) and the Electric Sector Modernization Plans (ESMPs), altering the manner in which utility distribution system planning is conducted in the Commonwealth.[75] The Act further clarified that in all decisions or actions related to rate designs, the DPU must consider the reduction of GHG emissions as required by law.[76] Further, the DPU issued a landmark order in D.P.U. 20-80 that will further drive electrification and decarbonization, including through increased requirements for considering alternatives to pipeline infrastructure, by requiring the gas distribution companies (i.e., Local Distribution Companies (LDCs)) to develop Climate Compliance Plans, and by directing the LDCs to propose targeted electrification projects.[77] Finally, *An Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers* (St. 2024, c. 239) was enacted on November 20, 2024 to accelerate progress towards the Commonwealth's GHG emission mandates.[78] This legislation will accelerate clean energy development, reform infrastructure siting and permitting, promote non-gas heating, expand access to EVs across the Commonwealth, and provide additional opportunities to improve energy affordability, further focusing the DPU's priorities throughout the energy transition.

While the DPU exercises its broad ratemaking authority through rate case proceedings governed by G.L. c. 164, § 94, the DPU is required to issue a decision on a timeline of 10 months in these proceedings. This expedited timeline of a rate case proceeding limits the DPU's capacity to

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[70] D.P.U. 94-158 at 1 (1995).
[71] Id.; *see* St. 1997, c. 164, *An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein* authorized state-level restructuring in Massachusetts.
[72] D.P.U. 07-50 (2008); St. 2008, c. 169, *An Act Relative to Green Communities*.
[73] St. 2021, c. 8.
[74] G.L. C. 25, § 1a.
[75] G.L. c. 164, §§ 92B, 92C.
[76] G.L. c. 164, § 141.
[77] D.P.U. 20-80-B, Order on Regulatory Principles and Framework (2023).
[78] St. 2024, c. 239.

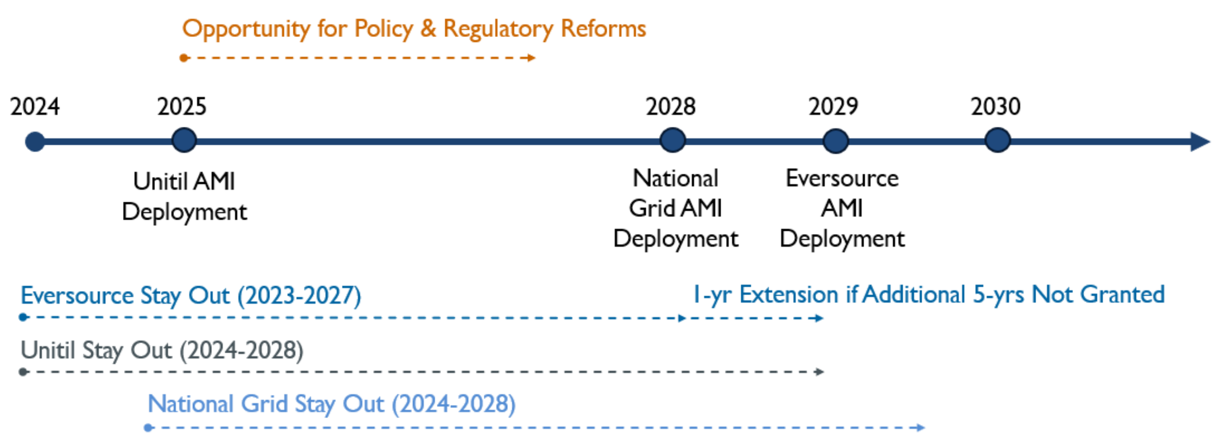
comprehensively evaluate—and the intervenors' capacity to meaningfully engage with—the regulatory framework, as was accomplished during previous regulatory inflection points in the energy transition via investigations, such as D.P.U. 94-158 and D.P.U. 07-50.

The Working Group expects that a DPU investigation will be a necessary step to critically and comprehensively examine the existing regulatory framework in light of the meaningful changes to the DPU's authority and priorities pursuant to recent legislation, as discussed above. The Working Group, informed by stakeholder feedback, recognizes that modifications to the existing regulatory framework are necessary to support a least-cost, reliable, and safe electric system and to ensure that capital investments are deployed and operated efficiently, and that electric rates are affordable. The Task Force will be an important venue to further this discussion.

Opportunity for Policy and Regulatory Reforms

Before the EDCs file their next base distribution rate cases, there is a key window of opportunity for policy and regulatory reforms to advance affordable electrification and decarbonization (see Figure 5 below). In the first half of 2025, the Task Force can develop issues for a potential petition to the DPU, followed, ideally, by a DPU investigation.

Figure 5: Rate Case Stay Out Periods and AMI Deployment Timeline[79]



Expand Non-Ratepayer Funding

Massachusetts offers nation-leading programs that subsidize heat pumps, solar generation, thermal building retrofits, and other energy efficiency measures, as well as programs that provide assistance

[79] Unitil will file its next rate case in mid-2028 for rates effective approximately mid-2029 (*see* D.P.U. 23-80 at 36-37 (2024)). Eversource may file a request to extend its current PBR plan term for another five-year term in mid-to-late 2027, in which case Eversource would file its next rate case in early 2032 for rates effective in early 2033. If an extension is not granted, Eversource's stay-out provision will be extended by one year for a rate case filing in early 2029 for rates effective in early 2030 (*see* D.P.U. 22-22 at 55-56). National Grid will file its next rate case in late-2028 for rates effective late-2029 (*see* D.P.U. 23-150 at 80-82).
[79] D.P.U. 23-80 at 408-409 (2024).

for arrearage (debt) management and discounts for low-income customers. The costs of these programs are recovered from electric ratepayers through the volumetric component of rates.[80]

The existing method of passing these program costs to ratepayers through volumetric rates may discourage the adoption of heat pumps and EVs by making the operation of these technologies less cost-competitive with fossil fuel alternatives (i.e., natural gas and propane, and internal combustion engine vehicles).[81] It also undermines affordability and equity by shifting the cost of the programs to customers who do not participate in energy efficiency or solar programs because customers who participate in these programs are able to reduce their net energy consumption, and thus they contribute less to the programs paid for through the volumetric component of rates. Many customers may not be able to utilize energy efficiency programs, net metering, or SMART incentives as fully as other customers because they are unable to pursue building retrofits or install solar panels on or batteries in their homes. Thus, these customers will not benefit from programs that reduce their net electricity consumption.

The existing method of recovering program costs from ratepayers is also inconsistent with ratemaking best practice – rates should be cost reflective. The cost of such programs – including the Residential Assistance Adjustment Factor (RAAF), Energy Efficiency Reconciliation Factor (EERF), SMART, etc. – has no causal relationship with the volumetric consumption of individual customers. In fact, in the case of solar and energy efficiency programs, participant incentives or rebates are part of program costs, but will likely reduce participating customer's contribution towards programs as their net electricity consumption is reduced. Recovering program costs through volumetric rates implies that the cost of these programs has a causal relationship to an individual customer's total consumption, while making electricity less affordable. **To address these issues, the Working Group recommends further consideration of: (1) funding certain programs through a fixed charge or through a combination of fixed and variable charges, to better align volumetric rates with cost causation; and (2) alternatives to ratepayer funding for certain programs (i.e., fund the programs outside of electric rates), to address affordability, equity, and cost causation concerns.** The Near-Term Rate Strategy Recommendations recommends that, in-lieu of alternative (non-ratepayer) funding sources, the cost of assistance programs, such as those programs supported by the RAAF, be considered for recovery via a fixed charge. While a fixed charge aligns with electrification efforts and ratemaking principals, it is still an imperfect solution of continuing to fund these programs through electric rates.

Further, the Massachusetts Office of Energy Transformation (OET), established in 2024, is exploring establishing alternative mechanisms to finance the future grid transition.[82] Specifically, the OET established a Financing the Transition Area Work Group (FTTWG) to identify alternative mechanisms to finance or fund EDC distribution system infrastructure upgrades necessary to achieve Massachusetts' clean energy and climate mandates.[83] The Working Group will continue to coordinate with OET and FTTWG to examine this recommendation to support decarbonization and electrification efforts, while also increasing energy affordability.

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[80] *See* Near-Term Rate Strategy Report at 22-23.
[81] *See* Near-Term Rate Strategy Report at 35-36.
[82] https://www.mass.gov/orgs/office-of-energy-transformation.
[83] https://www.mass.gov/orgs/financing-the-transition-work-group.

Appendix

Stakeholder Feedback Summary

Rate Design and Electrification

1. Time-Varying Rates (TVRs): Commenters expressed support for narrow peak windows and meaningful on-peak/off-peak differentials to motivate customer behavior. Several commenters recommended a default opt-out structure, paired with robust customer education, while others remained concerned about the potential for inequitable impacts, especially for households unable to adjust consumption.
2. Volumetric Charges and Demand Charges: Some stakeholders think that volumetric time-of-use (TOU) rates would send inefficient price signals and limit load management benefits compared to demand charges. Several stakeholders were concerned about the inequitable impacts of demand charges. Most stakeholders that commented on demand charges agreed that they should be peak coincident.
3. Shifting Peak Loads: Several stakeholders acknowledged the need to adopt rate structures that have built-in flexibility to account for the expected shift from summer to winter peaks due to electrification trends. One stakeholder noted that rates should focus on annual peaks.
4. Avoiding Penalties for Electrification: Many commenters raised concerns that switching to electricity from fossil fuels currently results in higher bills inhibiting the advancement of climate and equity goals.
5. Policy/Programmatic Alignment: A few stakeholders expressed the need for better alignment of ratemaking with other state initiatives, such as the Clean Heat Standard and electric vehicle (EV) incentive programs.
6. Embedded vs. Avoidable Costs: Many commenters agreed that TVR should be based on avoidable costs, while others disputed the avoidable vs. embedded distinction. Others commented that rates are best based on incremental costs, highlighting a need to clarify the framing used in the Long-Term Ratemaking Study.
7. Competitive Suppliers: Several stakeholders noted that competitive suppliers should also offer TVRs to maximize their benefits. One commenter recommended that competitive suppliers be granted more flexibility in offering alternative rate structures and should be able to offer delivery rates.
8. Fixed Charges: Several stakeholders do not support a higher fixed charge as a component of rate offerings, pointing out that high fixed charges can, for instance, weaken price signals, disincentivize distributed generation (DG) adoption, and harm low usage and low-income customers.

Customer Engagement, Outreach, and Education

1. Outreach and Education: Several stakeholders called for comprehensive outreach programs to help customers understand new rate structures, including shadow billing and

pilot programs for smoother transitions. Some stakeholders also recommended personalized rate education that utilizes advanced metering infrastructure (AMI) data to create customer-specific example bills.

2. Customer Understanding: Several stakeholders expressed that robust education programs are critical for successful adoption of new rate structures.
3. Pilot Programs and Shadow Billing: A few stakeholders provided that these strategies can help customers transition smoothly to new systems.

Equity and Affordability

1. Progressive Rate Structures: Many commenters advocated for rate designs where wealthier households pay more, ensuring lower- and middle-income households are not disproportionately burdened.
2. Protections for Low-Income Households: Many comments supported easier enrollment in discount rates and automatic eligibility verification to increase access. Many commented that low-income customers should be shielded from bill increases under TVR but should still be able to access potential savings. Other comments recommended rate designs tailored for renters, affordable housing residents, and households unable to electrify.
3. Energy Burden Reduction: Several commenters emphasized the importance of minimizing the cost impact of electrification on vulnerable populations, particularly during the transition to TVRs. Several commenters suggested coordinating recommendations with D.P.U. 24-15, which is an inquiry into energy burden.
4. Consumer-Oriented Transition to TVR: Several comments urged that the roll-out of TVR should be conducted carefully and with sufficient time to assess and prevent negative impacts to all customers.
5. Further Analysis: Several commenters recommended including additional analysis on the distributional impacts of alternate rate designs, as well as how measures like TVR-enabled load-shifting might affect bills by impacting overall revenue requirements.

Regulatory Framework and Utility Incentives

1. Performance-Based Regulation (PBR): Several stakeholders expressed interest in mechanisms like PBR and incentives tied to equity and decarbonization outcomes. Some commented that existing PBR measures could be improved.
2. Cost Recovery: Several stakeholders expressed concern about balancing necessary grid investments with affordability.
3. Stakeholder Inclusion: Several commenters advocated for transparent processes that incorporate historically marginalized voices and align utility incentives with the public interest.
4. Return On Equity (ROE) Adjustments: Several comments raised concern about the existing ROE levels for electric utilities, advocating for a reduced rate of return (ROR) to benefit consumers.
5. Shareholder Contributions: Several stakeholders proposed limiting shareholder profits to ensure investments are carefully managed and equitable.

6. Multi-Year Rate Plans and Formula Rates: Some stakeholders recommended well-designed multi-year and formula rate plans because they can lower prices, keep price changes moderate, and achieve improved efficiency and customer service.

Distributed Energy Resources and Grid Modernization

1. Integration with Other Clean Energy Policies: Some commenters expressed that rate reforms should remain aligned with other clean energy policies, such as the promotion of DG, community solar, energy efficiency, and demand response.
2. Support Distributed Energy Resource (DER) Adoption: A few stakeholders raised concerns about potential adverse impacts of rate design changes on community solar participation and broader DER deployment.
3. AMI: Commenters expressed support for leveraging AMI data to enable better rate designs and customer responsiveness. Comments further identified data access for third parties as important for advancing TVR.
4. DER and Rate Design Alignment: Commenters agreed with E3's presentation point that DER compensation programs must work together with rate design to send efficient price signals. However, changes to rate design and DER compensation should be considered separately.

Massachusetts Regulatory Framework Primer

This primer provides a summary of the Department of Public Utilities' (DPU's) treatment of key features in the existing regulatory framework in Massachusetts, but it is not exhaustive.

Cost-of-Service Regulation

The DPU has traditionally relied on cost-of-service (COS) regulation, also called rate of return (ROR) regulation, to establish electric rates that are "just and reasonable." "Just and reasonable" does not have a strict definition but is often interpreted as rates that include a cost of capital comparable to that of utilities of similar investment risk, sufficient to assure a utility's financial integrity, and adequate to maintain and support a utility's credit and to attract capital. Under this approach, as discussed further below, the DPU approves a "revenue requirement" for an electric distribution company (EDC), which is a calculation of the total annual amount of revenue the EDC needs to collect from ratepayers each year. While the DPU has implemented modifications to traditional COS regulation over the past two decades, base distribution rate cases continue to be focused on establishing a revenue requirement based on costs incurred in a twelve-month period (i.e., the test year), allocating those costs among customer classes, and then calculating and designing rates that customers will be charged. Currently, however, all three Massachusetts EDCs operate under performance-based regulation (PBR) plans discussed further below, implemented as a modification to traditional COS regulation.

The following sections include a brief overview of key features of COS regulation, including revenue requirement, test years, and cost-of-service studies (COSS), as well as how these components interact with alternative regulatory mechanisms under the existing regulatory framework.

Revenue Requirement, Rate Base, & Rate of Return

A utility's **revenue requirement** represents the total cost of service for the utility as approved by the DPU, including operation and maintenance (O&M) expense, taxes, depreciation and amortization expenses, and return on rate base.[84] In other words, revenue requirement is the calculation of the total annual revenue an EDC needs to recover from its ratepayers to account for the costs the company incurs to operate its electric system; to invest in additional capital to maintain and expand its system; and to earn a reasonable return, or profit, on capital investments. Table 1 below provides a summary of DPU-approved distribution service-related revenue requirements in fully adjudicated (i.e., non-settlement) base distribution rate cases over the past two decades.

[84] Revenue requirement is often represented with the following formula: Revenue Requirement = Operation & Maintenance + Taxes + Depreciation + (Rate Base * Return on Rate Base).

Table 1: Summary of Non-Settlement, DPU-Approved Revenue Requirement, $ million

National Grid	*D.P.U. 09-39*	*D.P.U. 15-155*	*D.P.U. 18-150*	*D.P.U. 23-150*
O&M Expenses	$315.1	$394.0	$431.2	$609.6
Depreciation and Amortization	$95.9	$133.4	$147.5	$189.2
Taxes other than Income Taxes	$43.4	$69.5	$78.2	$104.6
Income Taxes	$40.0	$56.0	$37.1	$36.2
Return on Rate Base	$119.4	$135.2	$162.7	$221.7
Other	($1.3)	$2.2	$1.4	$1.6
Total Revenue Requirement	**$612.2**	**$790.2**	**$858.2**	**$1,162.8**

Eversource	*D.P.U. 17-50 (NSTAR)*	*D.P.U. 17-50 (WMECO)*	*D.P.U. 22-22 (NSTAR & WMECO)*
O&M Expenses	$293.9	$62.7	$428.2
Depreciation and Amortization	$169.7	$28.4	$218.0
Taxes other than Income Taxes	$100.6	$19.2	$154.7
Income Taxes	$102.0	$18.9	$79.1
Return on Rate Base	$200.3	$31.7	$277.3
Other	$0.1	$0.3	$0.5
Total Revenue Requirement	**$866.5**	**$161.0**	**$1,157.8**

Unitil	*D.P.U. 07-71*	*D.P.U. 11-01*	*D.P.U. 13-90*	*D.P.U. 15-80*	*D.P.U. 23-80*
O&M Expenses	$7.7	$6.8	$9.7	$10.6	$15.0
Depreciation and Amortization	$4.0	$4.5	$8.6	$8.7	$7.4
Taxes other than Income Taxes	$0.9	$1.4	$1.6	$1.7	$2.1
Income Taxes	$1.4	$1.4	$1.6	$1.9	$1.6
Return on Rate Base	$4.5	$4.5	$4.3	$4.8	$6.3
Other	-	$1.6	-	-	-
Total Revenue Requirement	**$18.3**	**$20.2**	**$25.7**	**$27.6**	**$32.3**

O&M expenses generally represent the costs of operating the company and include labor, healthcare, insurance, uncollectible accounts, and enterprise information technology. O&M expenses are generally the annually recurring costs a utility incurs, such as maintaining its system and billing its customers. Massachusetts' EDCs are also responsible for several different types of taxes, including FICA, Medicare, federal unemployment, state unemployment, state insurance premium excise tax, tangible property tax, universal health tax, state sales and use tax, property taxes, franchise tax, and federal income tax.

Depreciation expense allows a utility to recover its capital investments in a timely and equitable fashion over the investment's useful life.[85] For example, if an investment is expected to be used for 30 years, that investment will be recovered from ratepayers over the 30 years of its useful life. Because depreciation expense is recognized as a non-cash expense leveraged as a funding source for capital expenditures (i.e., meaning that a utility can utilize the revenue collected associated with depreciation expenses for new investments),[86] the DPU often assesses a utility's inability to fund

[85] D.P.U. 23-150 at 224 (2024).
[86] D.P.U. 15-155 at 53, n.30 (2019).

capital expenditures by comparing its capital budget against its depreciation expense, as recovered in rates.[87] As the distribution companies make substantial investments in the electric distribution system during this current period of a transitioning energy system, depreciation expense collected from ratepayers is expected to grow as the amount of undepreciated rate base increases. While depreciation accounts for decreases in the value or worth of *tangible* assets, such as poles and wires, **amortization** accounts for the use of *intangible* assets (e.g., patents, leaseholds, etc.) that may not be recognized for the purposes of determining a utility's rate base.

Rate base generally refers to the net investment the utility currently has in service. More specifically, it refers to utility plant or investments that are in service, less offsetting liabilities like accumulated depreciation and accumulated deferred income taxes. The DPU reviews and approves utilities' **capital structure** (i.e., balance, or mix, of debt and equity financing) and the ROR for each form of capital. The **weighted average cost of capital (WACC)** is calculated based on the ROR for each form of capital and the amount of capital sourced from each and represents the ROR a company is allowed to earn on its investments.[88] Together, the product of the rate base and WACC rate determines the dollar amount of the allowed return on rate base that is included in the cost of service. Table 2 below provides a summary of DPU-approved cost of capital and rate base in fully adjudicated (i.e., non-settlement) base distribution rate cases over the past two decades.

Table 2: Summary of Non-Settlement, DPU-Approved Cost of Capital and Rate Base

National Grid	*D.P.U. 09-39*	*D.P.U. 15-155*	*D.P.U. 18-150*	*D.P.U. 23-150*
Long-Term Debt	5.96%	5.21%	5.22%	4.56%
Preferred Stock	4.44%	4.44%	4.44%	4.44%
Common Equity	10.35%	9.90%	9.60%	9.35%
Weighted Avg Cost of Capital	**7.85%**	**7.58%**	**7.56%**	**7.09%**
Total Rate Base ($million)	**$1,521.0**	**$1,783.1**	**$2,151.5**	**$3,125.6**
Return on Rate Base ($million)	$119.4	$135.1	$162.7	$221.7

Eversource	*D.P.U. 17-50 (NSTAR)*	*D.P.U. 17-50 (WMECO)*	*D.P.U. 22-22 (NSTAR & WMECO)*
Long-Term Debt	4.27%	3.97%	3.93%
Preferred Stock	4.56%	-	4.56%
Common Equity	10.0%	10.0%	9.80%
Weighted Avg Cost of Capital	**7.33%**	**7.26%**	**7.06%**
Total Rate Base ($million)	**$2,732.9**	**$436.4**	**$3.930.1**
Return on Rate Base ($million)	$200.3	$31.7	$277.3

[87] D.P.U. 15-80/81 at 48 (2016); D.P.U. 13-90 at 37 (2014); D.P.U. 11-01/02 at 79-80, 111 (2011).
[88] WACC is often represented as the following: WACC (%) = (share of debt (%) * return on debt (%)) + (share of equity (%) * return on equity (%)).

Unitil	D.P.U. 07-71	D.P.U. 11-01	D.P.U. 13-90	D.P.U. 15-80	D.P.U. 23-80
Long-Term Debt	6.99%	6.99%	6.99%	7.01%	5.34%
Preferred Stock	6.90%	6.74%	-	-	-
Common Equity	10.25%	9.20%	9.70%	9.80%	9.40%
Weighted Avg Cost of Capital	**8.38%**	**7.93%**	**8.28%**	**8.46%**	**7.46%**
Total Rate Base ($million)	**$50.5**	**$56.3**	**$51.9**	**$57.2**	**$84.3**
Return on Rate Base ($million)	$4.2	$4.5	$4.3	$4.8	$6.3

While the EDCs' base distribution charges reflect the cost to serve based on the DPU-approved revenue requirement, including the ROR, the EDCs increasingly recover additional costs from ratepayers outside of rate cases, through **reconciling mechanisms**. Reconciling mechanisms support both capital investments and O&M expenses[89] and effectively are accelerated cost recovery mechanisms. Reconciling mechanisms that support capital investment and associated expenses are referred to as **capital cost recovery mechanisms**.[90] Reconciling mechanisms are discussed further below in the Reconciling Mechanisms and Accelerated Cost Recovery section.

Test Year, Regulatory Lag, and Cost Containment

A **test year** represents a twelve-month snapshot of an EDC's financial situation. The DPU has had a long-standing precedent of relying on a **historical test year** (i.e., twelve-month period prior to the rate case filing) for a rate case, adjusted for changes in revenues and expenses that are known and measurable.[91] The DPU has considered historical cost figures as a reasonable representation of the cost to provide service, while forward-looking revenue and expenses may not be known with certainty and thus are not included in the historic test year or adjustments.[92]

An EDC makes capital expenditures in the period between its test year and the rate case filing date, referred to as **post-test year capital additions**,[93] as well as following the implementation of new

[89] Reconciling mechanisms include cost recovery for: internal and external transmission, pension/Post-Retirement Benefits Other than Pensions (PBOP), AMI implementation, residential assistance and customer debt management, net metering, revenue decoupling, attorney general consultant expense, long-term renewable contracts, capital costs, solar costs, grid modernization, basic service, vegetation management, storm reserve, exogenous cost, renewable resources, energy efficiency, energy efficiency reconciliation, and SMART.
[90] Capital cost recovery mechanisms are also referred to as capital trackers, capital recovery mechanisms, and capital expenditure recovery mechanisms. For this document, capital cost recovery mechanism is used for consistency.
[91] *See*, *e.g.*, D.P.U. 23-150 at 12 (2024); D.P.U. 23-80/81 at 274 (2024); D.P.U. 22-22 at 9 (2022); D.P.U. 14-150 at 45 (2020); D.P.U. 07-60-A at 52-53 (2007); D.P.U. 18204 at 4 (1975); D.P.U. 1580 at 13-17, 19 (1984); D.P.U. 136 at 3 (1980); *Massachusetts Electric Company v. Department of Public Utilities*, 383 Mass. 675, 680 (1981).
[92] *See*, *e.g.*, D.P.U. 22-22 at 10 (2022); D.P.U. 14-120 at 9 (2015); D.P.U. 1438/1595 at 3 (1984).
[93] For example, Unitil filed its most recent rate case on August 2023, based on a 2022 calendar test year. The DPU suspended the effective date of the proposed rate increase (*i.e.*, when rates change for customers) until July 2024 to conduct the proceeding. Capital investments made between January 2023 and August 2023, the date at which Unitil filed its rate case, are referred to as post-test year capital additions. Unless otherwise authorized, Unitil will earn neither a return of nor return on post-test year capital additions, or any capital investments made thereafter, until Unitil files its next rate case. This delay in recovery is an example of regulatory lag.

rates (i.e., following DPU approval and before the EDC's next rate case) to satisfy its obligation to provide safe and reliable service to its ratepayers. Under a historical test year (absent capital cost recovery mechanisms or post-test year capital additions), an EDC does not traditionally recover a return of (through depreciation expense), nor return on (through return on equity), for any particular capital expenditure that the company makes after the test year until those investments are approved in a base distribution rate case, where the DPU will review investments made since the last rate case to determine whether they were prudent and are "used and useful to ratepayers."[94] However, ratepayers do provide incremental funds through the depreciation expense component of the cost of service to support post-test year capital expenditures not yet reviewed and approved by the DPU, which may include the carrying cost of these investments (i.e., the capital, or financing, cost of these investments subject to the DPU's review and approval). Furthermore, the use of multi-year rate plans or formula-based rates, discussed further below, provides increasing funds from customers to support post-test year capital expenditures. Following the DPU's approval of investments in rate base, the EDC will begin to recover a return of and on those specific expenditures through base rates.

This dynamic – the delay in recovery between the time that a company incurs the cost of the capital investment and the time that it recovers that cost in its rates – is referred to as **regulatory lag**.[95] The DPU has acknowledged that regulatory lag is an important counterbalance to a utility's incentive to invest in capital. While capital investments provide a return to shareholders when included in rate base, which creates an incentive to increase rate base,[96] regulatory lag provides the utilities with an incentive to control costs and to invest in capital wisely.[97]

Using cost data from a historical test year to set base rates has been the main driver of regulatory lag between rate cases. However, the DPU's orders moving more investment recovery out of base rates and into capital cost recovery mechanisms, and its establishment of annual base rate revenue requirement increases (e.g., revenue cap formula and K-bar) within the EDCs' multi-year rate plans means that regulatory lag has been diminished. In effect, these mechanisms and adjustments provide the EDCs cost recovery either ahead of, coincident with the capital expenditure, or with a one-year delay. The DPU has recognized that capital cost recovery mechanisms are at odds with the principle of regulatory lag and has sought to preserve some of the associated cost containment incentives by implementing limits to provide some protections for customers.[98] In addition, the DPU

[94] D.P.U. 20-120 at 155 (2021); D.P.U. 19-120 at 161-162 (2020); D.P.U. 17-05 at 85 (2017). The DPU's standard of review on prudency involves a determination of whether a company's actions, based on all that it knew or should have known at that time, were reasonable and prudent in light of existing circumstances, and such determination must not properly be made on the basis of hindsight judgements. Further, it is inappropriate for the DPU to substitute its own judgement for the judgements made by the management of the company. Typically, the DPU applies a standard of "used and useful" to determine whether a plant investment is appropriately included in rate base, and evaluates whether the plant is in service and is providing net economic benefits to ratepayers.

[95] D.P.U. 15-80 at 50 (2016); D.P.U. 09-39 at 80 (2012).

[96] D.P.U. 15-80/81 at 50 (2016). The DPU has previously recognized this bias toward capital investment, which is known as the Averch-Johnson effect or "CapEx" (as opposed to "OpEx") bias.

[97] D.P.U. 09-39 at 80 (2012).

[98] D.P.U. 11-01/02 at 109, n.59 (2011).

has also allowed recovery of post-test year capital additions in limited circumstances, which further erodes regulatory lag and associated cost containment incentive.[99]

An alternative to a historical test year is a future, or forecasted, test year. A **future test year** reduces and, depending on the design, may eliminate regulatory lag by allowing the utility to set rates based on their forecasted costs. The potential benefit of using a future test year is that it accommodates rate-setting when utilities are faced with rapidly changing operating conditions. A future test year approach is currently utilized for various reconciling mechanisms in Massachusetts and by other regulatory commissions across the United States. In many of the existing reconciliation proceedings in Massachusetts, the EDC proposes, and the DPU reviews, a forward-looking revenue requirement and forecasted sales to establish rate levels. With the increasing use of, and magnitude of revenue represented in, reconciling mechanisms, the DPU effectively utilizes a future test year approach for the majority of customers' distribution charges. Base distribution rates generally reflect the approved revenue requirement, including the capital investments in rate base. As of January 2025, Eversource's base distribution rate ($0.06264/kWh) represents 33 percent of the total delivery rate ($0.19122/kWh) for residential customers. National Grid's base distribution rate ($0.06546/kWh) and Unitil's base distribution rate ($0.09621/kWh) are 36 percent of their total delivery rates ($0.18091/kWh and $0.26493/kWh, respectively).[100]

Cost-of-Service Studies

A critical step in the ratemaking process is the development of a COSS, which is performed to understand the costs of serving each customer class and inform rate design. The COSS is the starting point to allocate the revenue requirement across customer classes (e.g., residential, commercial and industrial, etc.). Two types of COSSs are employed across jurisdictions: (1) embedded, or allocated, COSSs; and (2) marginal COSSs. An **embedded COSS** allocates the EDC's revenue requirement across customer classes, while a **marginal COSS** focuses on how electric system costs change with an incremental increase in service.[101] Embedded COSSs are more common than marginal COSSs and focus on the current accounting costs associated with past investments that are currently in use. In other words, embedded COSSs may be preferred for ensuring EDC's rates are set at levels to recover the company's cost to serve, or revenue requirement.[102] Marginal COSSs are generally thought to be useful in designing rates that promote efficient price signals, as they provide information necessary to reflect the cost of incremental service to different customers. While a marginal COSS may inform efficient rate design, on its own it may not provide a utility the opportunity to recover its revenue requirement. Some regulators utilize both types: they leverage embedded COSSs to allocate costs *between* customer classes and utilize the marginal COSSs to inform rate design elements *within* classes.[103]

[99] D.P.U. 23-80/81 at 106 (2024); D.P.U. 15-80/81 at 53 (2016).
[100] https://www.mass.gov/info-details/massachusetts-electric-rates-and-tariffs.
[101] Whited, Melissa (2017). *The Ratemaking Process,* https://www.synapse-energy.com/sites/default/files/Ratemaking-Fundamentals-FactSheet.pdf.
[102] Id.
[103] Id.

The DPU traditionally required EDCs and LDCs to provide marginal COSSs as part of their rate case filings.[104] However, the DPU has not relied on marginal COSSs in designing electric rates.[105] Beginning in 2019, the DPU has not required marginal COSSs as part of electric base distribution rate cases, though the DPU identified the continued relevance of its accepted methodology and guidelines for utilities in preparing an appropriate marginal COSS.[106]

Revenue Decoupling, Reconciling Mechanisms, and Capital Investments

The Commonwealth's regulatory framework has evolved over the past two decades to support the deployment of energy efficiency, demand response, and distributed generation (DG) through (1) implementing revenue decoupling, which separates EDC revenues from customer sales; (2) providing revenue through reconciling mechanisms for investments that further the Commonwealth's clean energy and climate policies; and (3) establishing a long-term distribution system planning process. With the evolution of these regulatory tools to support decarbonization, there is likely a need to ensure that the regulatory framework is appropriately balancing decarbonization, the investments needed to achieve decarbonization, and affordability.

Following the adoption of **revenue decoupling** in 2008, the regulatory framework in Massachusetts evolved to increasingly rely on methods outside of rate cases (e.g., capital cost recovery mechanisms, other reconciling mechanisms, and authorized revenue requirement adjustments) to provide the EDCs with incremental revenue between rate cases. In part, these tools helped to provide investment capital that, prior to decoupling, was generated from additional kWh sales revenue. This relationship is discussed in more detail below.

While **reconciling mechanisms** and authorized revenue requirement adjustments provide incremental levels of revenue support between rate cases to support investments, programs, policies, or legislative directives, overreliance on this approach to fund policy objectives contributes to increasing electric rates across Massachusetts EDCs, which have outpaced the rate of inflation since 2019.[107]

Further, the Grid Modernization Advisory Council (GMAC) and the Electric Sector Modernization Plans (ESMPs), established through *An Act Driving Clean Energy and Offshore Wind* (St. 2022, c. 179), have also altered the manner in which the EDCs conduct distribution system planning, requiring the EDCs to conduct **long-term distribution system planning** of the investments needed to support Massachusetts' decarbonization goals.[108] Developed with the review, input, and recommendations of the GMAC, the ESMPs have the potential to provide transparency into grid planning that could help mitigate the EDCs' incentive to over-invest in distribution system capital investments and the

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[104] D.P.U. 18-150 at 516 (2019).
[105] Id. at 516-517. The DPU noted that it did not rely on a marginal cost study in designing rates for electric and gas companies, nor were utilities utilizing marginal cost studies for any purpose outside rate cases. Instead, it considered its rate design goals and relevant statutory requirements in evaluating rate designs. A marginal cost study may provide essential information to ensure load management and grid services are evaluated and compensation levels are established accurately.
[106] Id. at 517; *see, e.g.*, D.T.E. 05-27 at 317-322 (2005); D.T.E. 03-40 (2003), D.T.E. 02-24/25 at 243-245 (2002).
[107] Long-Term Ratemaking Study at 15, Figure 1.
[108] G.L. c. 164, §§ 92B, 92C.

potential adverse consequences associated with the throughput incentive that revenue decoupling is designed to eliminate.[109]

The following sections include a brief overview of revenue decoupling; reconciling mechanisms, including capital cost recovery mechanisms; and the Commonwealth's approach to long-term distribution system planning.

Revenue Decoupling

In 2008, the DPU concluded that a full revenue decoupling mechanism was necessary to reduce or eliminate the financial disincentive distribution companies face with respect to the deployment of customer-sited, cost-effective demand resources.[110] Revenue decoupling is a mechanism that separates EDC revenues from customer sales. That is, regardless of the volume of sales (kWh), an EDC will collect the same amount of revenue. This removes the financial disincentive to the EDCs related to energy efficiency and conservation efforts, which reduce sales. In other words, revenue decoupling is often employed to eliminate the "throughput incentive," the financial incentive for EDCs to sell more electricity to increase their revenues and earnings.[111] Under decoupling, the DPU establishes authorized revenues in addition to authorized rates. If customer sales end up lower than initially forecasted, rates can be adjusted upward to ensure that the distribution company recovers the level of total base distribution revenues authorized by the DPU in the last base rate case.

Since 2008, the Commonwealth's policy goals have evolved from decreasing electric sales by promoting energy efficiency and DG to also include increasing sales through electrification. In the 2022-2024 Energy Efficiency Three-Year Plan Order, the DPU found that the adoption of strategic electrification, to drive energy and greenhouse gas (GHG) reductions, eliminates the need for EDCs to employ revenue decoupling.[112] The DPU noted that beginning with the 2022-2024 Three-Year Plans, the delivery of energy efficiency programming in the Commonwealth, which includes substantial investment in the deployment of electrification technologies like air-source heat pumps, will result in a net increase in kilowatt-hour consumption, despite energy efficiency and demand response efforts designed to lower electric use.[113] The DPU concluded that full revenue decoupling must be discontinued for EDCs to ensure their business models align with the Commonwealth's policy goals.[114] The DPU found that it was appropriate to make this policy change "immediately," stating that: (1) it is no longer in ratepayers' best interest to make EDCs whole for lost sales; (2) timely discontinuation of revenue decoupling is necessary to align business interests of the EDCs with electric load growth in a safe, reliable, affordable, and equitable manner as the DPU considers several policies to advance the clean energy future (long-term system planning, grid modernization,

[109] D.P.U. 15-80/81 at 50 (2016). The DPU has previously recognized this bias toward capital investment.
[110] D.P.U. 07-50-A at 8-9 (2008). The DPU defined demand resources as "installed equipment, measures or programs that reduce end-use demand for electricity or natural gas… [and includes], but is not limited to energy efficiency, demand response, and distributed resources." D.P.U. 07-50-A at 6, n.1 (2008).
[111] While revenue decoupling may remove the financial incentive for EDCs to increase kWh sales, it neither removes the incentive for an EDC to make capital investments driven by peak demand (kW) growth nor incentivizes customers or the EDC to manage peak demand (kW) to reduce system costs.
[112] D.P.U. 21-120 through 21-129-A, Order at 227 (2022).
[113] Id. at 230.
[114] Id. at 232.

etc.); and (3) the change will shift risk associated with changes in lost revenues from customers to shareholders, while increasing the incentive to pursue and enable electrification.[115] The DPU noted that discontinuing revenue decoupling will remove the disincentive to promote strategic electrification, as the EDCs would be able to retain sales from increased load but would still be statutorily obligated to pursue all cost-effective energy efficiency.[116]

In 2024, however, the DPU found it reasonable and appropriate, with regard to Unitil's particular circumstances, to maintain full revenue decoupling.[117] In reconsidering its earlier directive on revenue decoupling (in the 2022-2024 Energy Efficiency Three-Year Plan Order), the DPU recognized "the complexities associated with evaluating the continuing role of full decoupling mechanism as EDCs ramp up their implementation of strategic electrification in the interest of decarbonization."[118] The DPU stated that "for the Commonwealth to meet its GHG reduction targets, both energy efficiency and strategic electrification will be necessary," indicating that decoupling in some form will continue to play a role in Massachusetts.[119]

National Grid, in its most recent rate case, did not file a proposal to discontinue revenue decoupling, and instead requested to defer the requirement until electric sales growth is more robust and a comprehensive rate design proceeding related to AMI capabilities results in new rate designs.[120] Similar to its decision in Unitil's last rate case, the DPU found it reasonable for National Grid to maintain revenue decoupling, concluding that maintaining revenue decoupling "properly balances the Company's demonstrated efforts to advance the Commonwealth's climate goals with the uncertainty surrounding the timing and extent of widespread acceptance of electrification and decarbonization alternatives."[121]

Electrification is a central strategy for the Commonwealth to meet its GHG reduction mandates and is itself a key energy efficiency solution (i.e., EVs utilize less energy for miles driven as compared to gasoline-powered vehicles, and electric heat pumps utilize less energy for heating as compared to gas-, oil-, or propane-fueled furnaces and boilers). Independent of revenue decoupling, the Commonwealth's energy efficiency programming through the Three-Year Plans and federal and state energy efficiency programming will ensure that all cost-effective energy efficiency continues to be pursued as required by law.[122] In fact, the Commonwealth has spent nearly two decades implementing all cost-effective energy efficiency through five Energy Efficiency Three-Year Plans since the passage of the Green Communities Act of 2008.[123] Most recently, the DPU approved the 2025-2027 Energy Efficiency Plan, which includes $4.5 billion in energy efficiency, demand

[115] Id. at 232-233.
[116] Id. at 234; G.L. c. 25, § 21.
[117] D.P.U. 23-80/81 at 417-419 (2024). The DPU recognized Unitil's concerns and challenges converting older structures within its service area to electricity and the potential affordability restraints given the economic demographics of Unitil's customer base, in addition to its credit profile.
[118] D.P.U. 23-80/81 at 418 (2024).
[119] Id.
[120] D.P.U. 23-150 at 553 (2024).
[121] Id. at 555.
[122] G.L. c. 25, § 21.
[123] The Utility Energy Efficiency PAs, overseen by the Energy Efficiency Advisory Council, have filed their 2025-2027 Three-Year Plan at the time of publication, which will be the sixth three-year plan.

reduction, and decarbonization investments in Massachusetts.[124] The Energy Efficiency Three-Year Plans are developed by the Energy Efficiency Program Administrators (PAs), overseen by the Energy Efficiency Advisory Council, and include a shareholder incentive for PAs to invest in load reductions – the DPU has acknowledged that these "performance incentives will continue to play an important role in encouraging distribution companies to pursue all cost-effective energy efficiency" following the discontinuance of revenue decoupling.[125]

In addition to load reductions due to ratepayer-funded energy efficiency measures, other state and federal efficiency and demand management policies have been implemented or expanded to reduce load from the largest sources of residential electricity use in Massachusetts' buildings, including, but not limited to, air conditioning, space heating, water heating, lighting, and appliances.[126] As a result of the Commonwealth's aggressive policies and programs to address traditional energy efficiency, the main driver of kWh sales increases will be from replacing fossil fuel-powered end uses with electricity-powered end uses, including furnaces/boilers to heat pumps, gas to electric water heating, clothes dryers, and cooking.

Load growth driven by electrification, complemented by load management strategies to minimize additional system costs, presents a meaningful opportunity for utilities and regulators to control the increase of electricity rates.[127] With the Commonwealth's principal decarbonization strategies being dependent on load growth, the future of revenue decoupling and its role in the regulatory framework remains an open question.

Reconciling Mechanisms and Accelerated Cost Recovery

Reconciling mechanisms are separate charges included on customer bills[128] that typically support recovery of costs associated with specific investments, programs, policies, and legislative directives. Reconciling mechanisms are adjusted periodically by reducing or increasing collection amounts based on actual and forecasted EDC expenditures. In Massachusetts, costs recovered in reconciling mechanisms are reviewed and collected separate from costs approved in each EDC's latest distribution rate case.

There are over 20 active reconciling mechanisms for the EDCs in Massachusetts.[129] Examples include: the net metering recovery surcharge; the long-term renewable contract adjustments; the

[124] D.P.U. 24-140 through 24-149, Order (2025).
[125] D.P.U. 21-120 through 21-129-B, Order at 234 (2022).
[126] *See*, 10 CFR 43110 CFR 431, https://www.ecfr.gov/current/title-10/chapter-II/subchapter-D/part-431; and 430, https://www.ecfr.gov/current/title-10/chapter-II/subchapter-D/part-430/subpart-C/section-430.32, G.L c. 25B, and 225 CMR 22; https://www.eia.gov/consumption/residential/data/2020/state/pdf/ce5.1.st.pdf.
[127] *See, e.g.,* Satchwell, et. al. *Qualifying the Financial Impacts of Electric Vehicles on Utility Ratepayers and Shareholders* (February 2023) https://emp.lbl.gov/publications/quantifying-financial-impacts; Shenstone-Harris, et. al. *Electric Vehicles Are Driving Rate Down for All Customers.* (Jan. 2024). https://www.synapse-energy.com/evs-are-driving-rates-down.
[128] Reconciling mechanisms are not included in base distribution charges.
[129] Not all active mechanisms apply to each EDC. Each EDC has around 15 reconciling mechanisms. For a list of all reconciling mechanisms, refer to the Massachusetts Electric Rates Database, prepared by E3 for the Interagency Rates Working Group (IRWG). The Electric Rates Database is available here: https://www.mass.gov/doc/massachusetts-residential-electricity-rates-database/download.

utility solar ownership cost recovery factors; storm costs adjustments; and the grid modernization, AMI, and EV program factors.

Reconciling mechanisms support both capital investment and O&M expense costs. A specific type of reconciling mechanism, considered a **capital cost recovery mechanism**, provides the EDCs with accelerated cost recovery for capital investments that support core goals of safety and reliability, and therefore may otherwise be considered business-as-usual investments. Following revenue decoupling and years of flat sales in the Commonwealth, due to energy efficiency and other demand-side resources efforts, the DPU and EDCs have increasingly relied on capital recovery mechanisms to provide cost recovery between rate cases.[130] However, if revenue decoupling is discontinued (i.e., recoupling), there may be no need for distribution related capital cost recovery mechanisms because recoupling would provide the EDCs with incremental revenue associated with load growth between rate cases, similar to the regulatory structure before revenue decoupling.[131] Some methods of recovering additional capital costs are designed to automatically adjust the base distribution revenue requirement (e.g., Eversource and Unitil's revenue cap formula and K-bar); these are not strictly separate capital cost recovery mechanisms, but are similar in effect because they provide an accelerated means of recovering additional capital costs outside of rate cases.

The DPU reviews the appropriateness of reconciling mechanisms by considering "whether the costs at issue are: (1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the [EDC's] control."[132] Consistent with the DPU's consideration of these specific criteria, there are practical reasons for using reconciling mechanism in certain cases, such as when the cost of a program is volatile or otherwise varies year to year, and therefore cannot be predictably set at a targeted rate for the duration of the time between rate cases. The Working Group, however, believes there are several aspects of reconciling mechanisms and their role in the regulatory framework going forward that need to be considered.

First, the use of reconciling mechanisms and other forms of accelerated cost recovery present rate design challenges. While higher volumetric rates may support conservation and reduced usage by customers,[133] the existing approach prices electricity above the cost of providing service because reconciling mechanisms support a range of programs, policies, and legislative directives that are not directly related to utility service. In turn, this increases the operational costs of electrification and may impact customers' choices regarding the adoption of heat pumps, EVs, and other electrified end uses.[134] Because reconciling mechanisms are included in customers' bills as volumetric charges but are not included in base distribution rates, rate changes that alter base distribution rates and do not

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[130] *See* D.P.U. 23-150 (2024); D.P.U. 23-80 (2024); D.P.U. 22-22 (2022); D.P.U. 18-150 (2019); D.P.U. 17-05 (2017); D.P.U. 15-155 at 40, 51-54 (2019); D.P.U. 15-80 at 50 (2016); D.P.U. 10-55 at 121-122, 132-133 (2010); D.P.U. 09-39 at 79-80, 82 (2012); D.P.U. 09-30 at 133-134 (2009).
[131] D.P.U. 22-22 at 80, n.38 (2022).
[132] D.P.U. 23-150 at 603 (2024), citing D.P.U. 19-120 at 287-288; D.P.U. 10-55 at 66, n.43 (2010); D.T.E. 05-27 at 183-186 (2005); D.T.E. 03-47-A at 25-28, 36-37 (2003).
[133] D.P.U. 07-50-A Order at 49-59 (2008). The DPU has explicitly extended the volumetric approach to reconciling mechanisms, in part, to further promote conservation.
[134] *See, e.g.,* Borenstein, Severin and James Bushnell. *Headwinds and Tailwinds: Implications of Inefficient Retail Energy Pricing for Energy Substitution.* (July 2021). https://haas.berkeley.edu/wp-content/uploads/WP319.pdf.

alter reconciling mechanisms will impact a small percentage of customers' overall bills, thus diluting price signals.

Second, reconciling mechanisms and other forms of accelerated cost recovery also impact the degree of financial risk for EDC shareholders, the degree of certainty that EDCs will recover its costs, and the timeline for EDC cost recovery. The DPU has noted that the use of reconciling mechanisms reduces risk for the EDCs by shifting financial risk from shareholders to customers.[135] There is also less uncertainty that the utility will recover costs from ratepayers for capital investments, O&M expenses, employee compensation, etc., when those costs are recovered in reconciling mechanisms or via other forms of accelerated cost recovery, compared to when those costs are subject to review in base distribution rate cases. The associated reduction in regulatory lag also provides utilities with greater certainty that they will recover incremental costs close to when they are incurred (i.e., it provides for faster recovery compared to recovery after a rate case order).

Third, and as the Working Group has highlighted in this document and in its Near-Term Rate Strategy Recommendations, the use of a reconciling mechanism to fund a program or policy, such as the costs for the low-income discount rate, that could be funded outside of rates, contributes to increasing electric rates and in turn affordability challenges and a disincentive to electrify end uses.

Integrated Distribution System Planning

The 2022 Climate Law requires the EDCs, via their ESMPs, to prepare short-term forecasts, long-term forecasts, and demand assessments through 2050 that include, but are not limited to, "future trends in the adoption of renewable energy, distributed energy resources [DERs] and energy storage and electrification technologies necessary to achieve the statewide GHG emission limits and sublimits under chapter 21N."[136] The DPU approved the first ESMPs as strategic plans intended to outline the EDCs' investments in their respective electric transmission and distribution systems required to enable an affordable and equitable energy transition.[137] The 2022 Climate Law also established the GMAC, an interdisciplinary stakeholder body that, among other activities, reviews and provides recommendations on the EDCs' ESMPs. The GMAC is charged with increasing the transparency of and stakeholder engagement in the grid planning process.

As planning documents, the ESMPs will directly impact ratemaking in multiple ways. For example, G.L. c. 164 § 92B(d) contemplates that the ESMPs' capital spending proposals may be recovered through base distribution rates, which may be necessary if and when the DPU decides to end the interim ESMP cost-recovery mechanism.[138]

As strategic plans, the ESMP process should improve grid planning and could help to better align capital spending and cost recovery with decarbonization efforts. Robust long-term system planning may also drive innovation in regulatory processes and ratemaking. The DPU has approved the inaugural ESMPs, and in commencing the second phase of the proceeding, stated its intention "to

[135] *See*, *e.g.*, D.P.U. 18-150 at 495 (2019); D.P.U. 12-76-B at 22 (2014), citing D.P.U. 09-39 at 81-84; D.P.U. 07-50-A at 49-50 (2008); D.T.E. 05-85 at 10 (2006).
[136] G.L. c. 92 B(c)(i).
[137] D.P.U. 24-10 through 24-12 at 1 (2024).
[138] D.P.U. 24-10 through 24-12 at 447 (2024).

investigate how innovative approaches to cost recovery through base distribution rates can further the purpose of G.L. c. 164, § 92B, optimally balance [DPU] priorities, and promote efficiency."[139] Together, these changes and processes present an opportunity for the DPU to comprehensively consider how to change the regulatory framework to support affordable electrification and decarbonization.

Performance-Based Regulation in Massachusetts

In 1994, the DPU initiated an investigation into incentive-based regulation, sometimes referred to as performance-based regulation or PBR, for electric and gas companies. The DPU considered whether consumers would benefit from alternative regulatory approaches.[140] PBR refers to a set of regulatory strategies or mechanisms employed to more closely align an EDC's financial incentives with specific public interests, as compared to traditional COS/ROR regulation. While a PBR framework was developed in the early- to mid-1990's, EDC adoption of incentive-based frameworks was limited until 2017.[141]

A PBR mechanism is considered an adjustment to traditional COS/ROR ratemaking. As such, the DPU determined that incentive proposals would be subject to the traditional standard of review, namely that resulting rates must be just and reasonable.[142] An EDC proposing an incentive regulation approach must demonstrate that such a proposal is more likely than existing regulation to advance the DPU's traditional goals of safe, reliable, and least-cost energy service, and must also promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation.[143]

The DPU has implemented PBR plans or PBR-like mechanisms for all three EDCs operating in the Commonwealth, finding that such regulatory methods better satisfy public policy goals and statutory obligations compared to prior regulatory approaches.[144,145] Each EDC's PBR plan includes a 5-year rate formula, which is intended to limit when an EDC can file its next rate case.

The following sections provide a brief overview of PBR mechanisms that have been implemented in the Commonwealth, including formula-based rates, or multi-year rate plans; earnings shared mechanisms; and performance metrics.

Formula-Based Rates and Multi-Year Rate Plans

Formula-based rates and multi-year rate plans are two approaches to utility regulation that provide utilities with heightened predictability for forward-looking revenue recovery. Each of these approaches provide utilities with expedited cost recovery, reduce regulatory lag, and reduce the

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[139] D.P.U. 24-10 through 24-12, Procedural Notice at 8 (2024).
[140] D.P.U. 94-158 (1995).
[141] *See* the Long-Term Ratemaking Study at 45-48 for a survey of existing PBR mechanisms in the Commonwealth.
[142] D.P.U. 94-158 at 52 (1995); *Attorney General v. Department of Telecommunications and Energy,* 438 Mass. 256 n.13 (2002).
[143] D.P.U. 94-158 at 57 (1995).
[144] D.P.U. 22-22; 20-120; 19-120; 18-150; 17-05. Note that several gas utilities, or LDCs had similarly structured PBR plans prior to the adoption by EDCs (*see*, *e.g.*, D.T.E. 05-27; 03-40; 01-56; 99-47).
[145] D.P.U. 96-50 at 261 (1996); D.P.U. 94-158 at 42-43 (1995); D.P.U. 94-50 at 139 (1994).

frequency of rate cases. Formula-based rates periodically adjust the revenue requirement based on a predefined formula, whereas multi-year rate plans set rates for a multi-year term, typically based on forward-looking revenue requirement.

The DPU has implemented a revenue requirement limit or "revenue cap" formula (i.e., formula-based rates) as a core part of PBR for the EDCs. In practice, the DPU uses COS/ROR regulation to establish the revenue requirement in a base rate case, which serves as the starting point for the first year of base rates. The revenue requirement is then annually adjusted using an approved formula to arrive at each following year's revenue cap that can be recovered via electric rates for the duration of the PBR multi-year rate plan. In effect, the PBR mechanism has allowed the EDCs to increase their base distribution rates on an annual basis through the revenue cap formula.

The DPU has noted that the utilities need to undertake substantial capital investment to meet the Commonwealth's clean energy transition goals of increased electrification and decarbonization, and has credited PBR plans, including formula-based rates, as effective tools for maintaining rate stability and predictability during periods of system investment.[146]

The revenue cap formula in Massachusetts has generally been defined as follows:

$$Revenue_t = (Revenue_{t-1} * (1 + i_t - X - CD)) + Z_{t,}$$

where $Revenue_t$ represents a given year's revenue cap; $Revenue_{t-1}$ represents the prior year's revenue cap; i_t is a measure of inflation in the given year; X is a "productivity" factor or offset; CD is a "consumer dividend;" and Z_t is an "exogenous cost mechanism."

The design and purpose of the formula is to create limitations for the EDCs' spending that infuses some aspects of a competitive market with some protections to ensure the EDCs' revenues are sufficient to recover costs plus a reasonable return. The inflation measure (i_t) uses the Gross Domestic Product Price Index (GDP-PI) to account for inflation in the prices of goods and services economy-wide. The productivity offset (X) is designed to account for a difference in productivity and input prices of the electric sector compared to the economy. Together, the inflation and the productivity offset are intended to infuse an efficiency signal to the EDC, as if they were facing a competitive market. The CD is intended to share any efficiency gains achieved by the EDC under the PBR plan with ratepayers. The exogenous cost mechanism (Z_t) is a fail-safe that can be used to adjust rates under unforeseen circumstances not captured by inflation and are beyond the control of a company. The development and selection of the productivity offset (X) and CD are typically highly contested issues in adjudicatory proceedings, given that each helps to define annual electric rate increases allowed under a PBR plan. The Working Group notes that delivery rates have outpaced inflation, in part due to increases associated with the cumulative impacts of PBR adjustments.

Intended Benefits of Formula-Based Rates and Multi-Year Rate Plans

With regards to the intended benefits of formula-based rates, the DPU has noted that PBR plans, which in Massachusetts have been implemented with revenue cap formulas, support the ability of EDCs to adapt to a changing regulatory environment and to navigate the demands of the

[146] D.P.U. 23-150 at 81 (2024); D.P.U. 23-80/81 at 37 (2024); D.P.U. 22-22 at 54-55 (2024).

Commonwealth's energy transition in an efficient, cost-effective manner.[147] In particular, the DPU has found PBR plans provide more flexibility in responding to changes in energy and climate policy, emerging technologies, staffing, upgrading and maintaining aging infrastructure, frequency and intensity of storms, and higher customer expectations.[148] In addition, the DPU has previously recognized that ratepayers benefit from the cost containment and efficiency incentives under PBR.[149] However, as the Long-Term Ratemaking Study notes, assessing the effectiveness of these findings is difficult as there is no basis for comparison of rates absent these strategies.[150]

Typically, formula-based rates and multi-year rate plans are established for several years into the future and can include stay-out provisions intended to delay or avoid additional rate cases. The DPU has approved terms of five years for EDCs.[151] Further, the DPU has found that PBR terms should be sufficiently long, to allow for the EDCs to have the resources and flexibility to adjust operations and investment efficiently, providing a benefit to ratepayers by ensuring incentives for cost containment.[152] However, the annual revenue adjustments may exceed actual costs the EDC faces, in which case this approach would diminish the incentive for cost containment. Furthermore, there is no established limit on an increase in rates that an EDC could propose at the end of the five-year term, which may undermine the ratepayer benefits of the structure of this form of incentive regulation.

According to the EDCs, formula-based rates and multi-year rate plans have been effective in reducing the frequency of rate cases. The DPU has previously recognized that PBR plans have reduced the regulatory and administrative burden and costs associated with rate cases.[153] While rate cases require a significant amount of work on the part of the EDCs, DPU, and intervenors, they also represent a central tenant of the economic regulation of monopoly utilities and are a key lever of the DPU's supervision and oversight responsibility.[154] The reduction of the number of rate cases may not be a customer benefit in and of itself, and the reduction of regulatory and administrative costs associated with reduced rate cases must be weighed against the drawbacks.

In support of the EDC's stay-out proposals, the EDCs have provided estimates of the number of base distribution rate cases they would file without a PBR plan in place. Recently, the EDCs have identified they would need at least one additional rate case in a five-year period, if not up to four rate cases in

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[147] D.P.U. 23-80/81 at 34 (2024).
[148] D.P.U. 23-150 at 78-79 (2024); D.P.U. 22-22 at 51-52 (2024); D.P.U. 18-150 at 53 (2019).
[149] D.P.U. 23-150 at 79 (2024); D.P.U. 22-22 at 52-55 (2024); D.P.U. 19-120 at 63-65 (2020); D.P.U. 18-150 at 53-55 (2019); D.P.U. 17-05 at 402-403 (2017); D.P.U. 96-50 (Phase I) at 320 (1996); D.P.U. 94-158 at 64 (1995).
[150] Long-Term Ratemaking Study at 46.
[151] The DPU has also approved terms of five and ten years for LDCs. D.P.U. 23-150 at 81 (2024) (five years); D.P.U. 23-80/81 at 37 (2024) (five years); D.P.U. 22-22 at 54 (2024) (five years, with a possible five-year extension); D.P.U. 20-120 at 72 (2021) (five years); D.P.U. 19-120 at 65 (2020) (ten years); D.P.U. 18-150 at 56 (2019) (five years); D.T.E. 03-40 at 495-496 (2003) (ten years); D.T.E. 01-56 at 10 (2002) (ten years); D.P.U. 96-50 (Phase I) at 320 (1996) (five years).
[152] D.P.U. 23-150 at 81 (2024); D.P.U. 23-80/81 at 37 (2024); D.P.U. 22-22 at 55 (2024); D.P.U. 18-150 at 55 (2019); D.P.U. 17-05 at 403 (2017).
[153] D.PU. 23-150 at 79 (2024); D.P.U. 22-22 at 52-55 (2024); D.P.U. 19-120 at 63-65 (2020); D.P.U. 18-150 at 53-55 (2019); D.P.U. 17-05 at 379, 402-403 (2017); D.P.U. 96-50 (Phase I) at 320 (1996); D.P.U. 94-158 at 64 (1995).
[154] G.L. c. 164, §§ 76, 94; c. 25, § 1A.

a ten-year period.[155] These estimates are generally based on the EDCs' capital plans informed by forecasted costs and assumptions of investment needs, which involves a degree of uncertainty, or risk, characteristic of all forecasted costs and investment. Traditionally, the regulatory burden and costs of a rate case would incentivize the EDC to manage this risk by controlling operational costs or optimizing distribution system operations to defer or avoid capital costs to delay a rate case. When capital cost recovery mechanisms and formula-based revenue requirement are utilized, the risk borne by the EDC in some ways shift onto customers.

Earning Sharing Mechanisms

The DPU has found that earning sharing mechanisms (ESMs) are an integral part of incentive regulation plans as they provide an important backstop to uncertainty associated with the productivity factor[156] and protect ratepayers in the event that expenses increase at a rate much lower than that at which the authorized revenue increases.[157] Typically, the ESM operates as an asymmetrical adjustment in the event the EDCs' ROE exceeds the approved ROE by an amount greater than a specified range, or deadband. Currently, the Massachusetts EDC have ESMs with deadbands of 100 basis points, or 1 percent, and share 75 percent of earnings above the deadband with customers while retaining the remaining 25 percent if earnings exceed the authorized ROE. National Grid, Eversource, and Unitil's ESMs will be triggered when the EDCs' ROEs exceed 10.35 percent, 10.8 percent, and 10.4 percent, respectively.[158] Notably, the ESM has not been triggered during any of the EDCs' PBR terms. While the ESM has not yet been triggered, it could be an important mechanism to protect ratepayers, even absent PBR formula-based rates or multi-year rate plans.

Performance Metrics

Performance metrics are regulatory tools intended to monitor and improve the performance of electric utilities. There are three primary types of performance metrics employed in utility regulation: reporting metrics, which require data reporting; scorecard metrics, which define a baseline and a target, and report on progress towards the target; and performance incentive mechanisms (PIMs), which provide a financial incentive or penalty for meeting a target. If designed well, these mechanisms can incentivize utilities to meet specific performance goals beyond what traditional COS regulation provides, aligning utility behavior with broader public policy objectives.

The DPU has found it appropriate to establish broad performance metrics tied to the goals of a particular EDC's PBR plans and that are consistent with the DPU's regulatory objectives to measure the full range of benefits that will accrue under PBR plans.[159] For each PBR plan, the DPU has

[155] D.P.U. 23-150 at 77 (at least one rate case over five-year term); D.P.U. 23-80/81 at 33-34 (at least one rate case over five-year term); D.P.U. 22-22 at 50 (up to four rate cases through a ten-year term); D.P.U. 17-05 at 379 (at least one over five-year term).
[156] D.P.U. 17-05 at 400 (2017); D.P.U. 96-50 (Phase I) at 325 (1996); D.P.U. 94-50 at 197 & n.116 (1994).
[157] D.P.U. 18-150 at 70 (2019); D.P.U. 17-05 at 400 (2017); D.P.U. 10-70 at 8, n.3 (2011); D.T.E. 05-27 at 404-405 (2005).
[158] D.P.U. 23-150 at 93-94 (2024); D.P.U. 23-80/81 at 49-51 (2024); D.P.U. 22-22 at 70 (2024).
[159] D.P.U. 22-22 at 115 (2024).

approved metrics to measure EDC performance intended assure customers and stakeholders that standards of service are maintained or improved and that clean energy goals are advanced.[160]

The DPU has approved various reporting metrics, scorecard metrics, and PIMs. The following categories of PBR metrics, in Table 3 below, have been approved for the three Massachusetts EDCs.

Table 3: Approved Performance-Based Regulation Metrics

Eversource		National Grid		Unitil	
Metric	***Type***	***Metric***	***Type***	***Metric***	***Type***
Overall Customer Satisfaction	Scorecard	Low-Income Discount Rate Enrollment	PIM	Customer Satisfaction with Customer Service	Scorecard
Business Customer Satisfaction	Scorecard	DER Interconnection	PIM	Digital Engagement	Scorecard
Transactional Customer Satisfaction	Scorecard	Company GHG Emissions Reductions	Scorecard	Peak Demand Reduction	Scorecard
Outage Map Usage	Scorecard	Fleet Electrification	Scorecard	GHG Emissions Reductions	Scorecard
Digital Engagement	Scorecard	Low-Income Terminations	Reporting	Low-Income Terminations	Reporting
New Customer Connections	Scorecard	First Call Resolution	Reporting		
Producer Satisfaction Survey	Scorecard	Digital Customer Engagement	Reporting		
Hosting Capacity Map Usage	Scorecard	DER Participation Program	Reporting		
Solar Development Timeline	Scorecard	Customer Satisfaction	Reporting		
Peak Demand Reduction	Scorecard	Outage Communication	Reporting		
GHG Reduction	Scorecard				
Low-Income Terminations	Reporting				
Resiliency	Reporting				

While reporting and scorecard metrics provide information on performance, they do not provide a financial incentive for a company to align performance with regulator or other stakeholder objectives. PIMs, on the other hand, can be designed to provide a financial incentive to achieve an end-goal that is in stakeholders' interest.

[160] D.P.U. 23-150 at 79 (2024); D.P.U. 23-80/81 at 35 (2024); D.P.U. 22-22 at 53 (2024).

The financial incentive of a PIM may reward or penalize utilities for performance relative to specified benchmarks or targets. For example, the DPU developed guidelines for an Energy Efficiency PIM in 2009, providing the utilities the opportunity to earn incentives associated with pursuing GHG reductions, energy efficiency, and demand reduction efforts with an update in 2021 to reward investment in environmental justice communities.[161] In this case, the performance incentives are set as a percentage of overall budgets (e.g., the performance incentive pool was 3.9 percent of the 2022-2024 budget). The proposed incentives for the 2025-2027 Three-Year Plan are $190 million for electric and gas utilities.[162] Other PIMs also exist in Massachusetts today for service quality guidelines and interconnection timeline enforcement mechanisms (TEMs). Most recently, the DPU has approved two PIMs for National Grid: (1) DER interconnection; and (2) low-income discount rate enrollment.[163]

[161] Massachusetts Energy Efficiency Advisory Council Resolution Regarding the 2022-2024 Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Investment Plans. (Oct. 2021).
[162] D.P.U. 24-140 through 24-149 (2025).
[163] D.P.U. 23-150 at 150-151, 161 (2024).

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Long-Term Ratemaking Study Affordability Feedback

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Introduction

This document includes a set of recommendations relevant to the Long-Term Ratemaking Study ("Long-Term Study") conducted by E3 and commissioned by the Interagency Rates Working Group (IRWG). As I understand it, Massachusetts is deploying Advanced Metering Infrastructure (AMI), and the IRWG is exploring the options for, and impacts of, AMI-enabled electric rates. As I discuss them here, time-varying rates, or TVR, is a general term for electric rates that vary with time, and time-of-use (TOU) rates are structures that seek to encourage shifting energy consumption from peak to off-peak hours by using predefined pricing periods. I first discuss the benefits afforded by AMI as it relates to TVR, I then provide key, general considerations for TVR. I will also touch on TOU rates which are a type of TVR pricing scheme that consists of pre-defined peak and off-peak time periods with a tiered pricing structure for each.

Advanced Metering Infrastructure (AMI) Benefits

Beyond its role in identifying at-risk homes,[164] AMI provides an important opportunity to gain visibility into price responsiveness across income groups. This visibility will become particularly relevant with the rollout of TVR. AMI data can help assess whether low-income households are disproportionately impacted by on-peak pricing, especially during extreme weather events. These households often

[164] There are a multitude of examples of how AMI data can be used to identify at risk households. See for example this research paper Huang, L., Nock, D., Cong, S., & Qiu, Y. L. (2023). Inequalities across cooling and heating in households: Energy equity gaps. Energy Policy, 182, 113748. In addition, there is a company called Peoples Energy Analytics which implements this into practice. See also, Appendix: Near-Term Rate Strategy Report Affordability Feedback.

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face compounded effects of poor insulation, high heating or cooling loads, and elevated on-peak rates. TVR should be designed to avoid increasing bills for vulnerable customers. Vulnerable customers at risk can include low-use customers who are unable to shift their consumption in order to avoid high energy bills.[165] Some reasons that low-users may be unable to shift their energy consumption include durable medical equipment or lack of shiftable loads (e.g., lacking an air conditioner or dishwasher). Many households already limit their energy use,[166] and introducing peak pricing periods may inadvertently incentivize further reductions, potentially leading to adverse health outcomes such as asthma, exposure to unsafe indoor temperatures or indoor air pollution (e.g., burning trash in home to stay warm), and mental health issues induced by stress.[167] In addition to protections for low-use and low-income consumers, there should also be considerations for populations of people who, regardless of income, may be forced to have higher use because of caregiving for people with disabilities or having young children in the home. For example, a family

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[165] Here low-use customers are assumed to be limiting their energy consumption based on the inability to pay higher energy bills. See for example populations who limit their cooling usage: Kwon, Minji, Shuchen Cong, Destenie Nock, Luling Huang, Yueming Lucy Qiu, and Bo Xing. "Forgone summertime comfort as a function of avoided electricity use." Energy Policy 183 (2023): 113813.

[166] Here energy limiting behavior is defined as the “inability or unwillingness to consume enough energy to reach a desired level of comfort.” Reference: Cong, Shuchen, Arthur Lin Ku, Destenie Nock, Charlotte Ng, and Yueming Lucy Qiu. "Comfort or cash? Lessons from the COVID-19 pandemic's impact on energy insecurity and energy limiting behavior in households." Energy Research & Social Science 113 (2024): 103528.

[167] See these studies for further reading: Fabian, Maria Patricia, Gary Adamkiewicz, Natasha Kay Stout, Megan Sandel, and Jonathan Ian Levy. "A simulation model of building intervention impacts on indoor environmental quality, pediatric asthma, and costs." Journal of Allergy and Clinical Immunology 133, no. 1 (2014): 77-84; Fabian, Patricia, Gary Adamkiewicz, and Jonathan I. Levy. "Simulating indoor concentrations of NO2 and PM2. 5 in multifamily housing for use in health-based intervention modeling." Indoor Air 22, no. 1 (2012): 12-23; Chen, Chien-fei, Xiaojing Xu, and Julia K. Day. "Thermal comfort or money saving? Exploring intentions to conserve energy among low-income households in the United States." Energy Research & Social Science 26 (2017): 61-71; Brown, Marilyn A., Anmol Soni, Melissa V. Lapsa, Katie Southworth, and Matt Cox. "High energy burden and low-income energy affordability: conclusions from a literature review." Progress in Energy 2, no. 4 (2020): 042003.

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with children under 5 may choose to set warmer indoor temperatures in the winter, but at the expense of other survival needs (e.g., food and medicine).[168]

As noted in the Long-Term Study, the electrification of transportation and heating will require enhancements to the distribution network, leading to increased costs. Protections for hyper vulnerable customers[169] are essential to address affordability challenges. There should be data driven approaches for tracking affordability concerns in the region. I recommend using data in two ways:

1. I recommend that with each substantial rate change (either a net increase from a rate case, or a change in rate design enabled by AMI (i.e., implementing TVR), an analysis be conducted using historic (at least three years) and post-hoc data (at least annually) to track energy burden and energy limiting behavior. The data analytics should involve calculating energy burdens and energy limiting behavior (early[170] and late[171] season data, for both cooling and heating).

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[168] There is ample research on this topic. See for example: Brown, Marilyn A., Anmol Soni, Melissa V. Lapsa, Katie Southworth, and Matt Cox. "High energy burden and low-income energy affordability: conclusions from a literature review." Progress in Energy 2, no. 4 (2020): 042003; Hernández, D., Jiang, Y., Carrión, D., Phillips, D., & Aratani, Y. (2016). Housing hardship and energy insecurity among native-born and immigrant low-income families with children in the United States. Journal of Children and Poverty, 22(2), 77-92.

[169] Hyper vulnerable populations include income restricted (e.g., low-income and retirees) households, households with children under the age of 5 and households with durable medical equipment.

[170] Huang, Luling, Destenie Nock, Shuchen Cong, and Yueming Lucy Qiu. "Inequalities across cooling and heating in households: Energy equity gaps." *Energy Policy* 182 (2023): 113748.

[171] Kwon, M., Cong, S., Nock, D., Huang, L., Qiu, Y. L., & Xing, B. (2023). Forgone summertime comfort as a function of avoided electricity use. *Energy Policy*, *183*, 113813.

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2. The second data sources I recommend using are late bill payment and chronic disconnection information, which are additional proxies for energy affordability. Late bill payments and disconnection notices indicate energy payment hardships. In hyper vulnerable households, arrears and chronic lateness can lead to disconnection and increased costs to reconnect to service. The timeframe for analyzing this data to target bill assistance should focus on the number of late payments within six billing cycles in order to identify households before they receive a disconnection or disconnection notice.

Following the identification of at-risk customers, the utility or another representative should reach out to customers to make them aware of bill assistance and energy efficiency technologies along with associated rebates and incentives. Then the energy consumption data should be used for monitoring energy consumption changes and energy affordability on an ongoing basis. The goal of this monitoring should be to identify at-risk households and connect them to energy assistance, which can enhance overall well-being and health in the region.

By analyzing AMI data, stakeholders can identify and mitigate potential inequities in energy burdens and energy limiting behavior. AMI data analysis should be conducted across income groups, and particularly for hyper vulnerable groups. When tying demographic data to households, the spatial resolution should be no larger than a census tract.

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Key Considerations for Time-Varying Rates (TVR)

Key considerations for TVR design include:

1. **Price Signal Communication**: Price signals should be framed in terms of their impact on monthly energy bills rather than as cost per kWh. Customers are more likely to understand and respond to changes if they see the tangible effects on their monthly bills.
2. **Participation in Load Shifting**: Households' ability to participate in load shifting depends heavily on access to enabling technologies that help to program the use of appliances, electric vehicles, and heat pumps with low-cost TVR periods. While the Commonwealth is actively working to deploy these technologies and electrify homes, continued efforts are needed to reduce the upfront cost barriers for hyper vulnerable populations. As referenced in footnote 6, hyper vulnerable populations include income restricted (e.g., low-income and retirees) households, households with children under the age of 5 and households with durable medical equipment. An equitable energy transition would strategically deploy resources to hyper vulnerable populations and then expand the reach of programs to low-income broadly, to people on and just above the cusp of existing definitions of

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multidimensional energy poverty[172] and insecurity,[173] followed by middle income and high-income households.

3. **Affordability Protections**: When TVR rates are available, as noted above, AMI will enable the analysis of the impact of a TVR rate rollout. Monthly and daily energy usage data should be tracked for three years prior and then each year following a TVR rate rollout. It is noted in the Long-Term Study that TVR yielded more bill savings across the low-income customer base than bill increases for PG&E customers,[174] indicating that delaying the transition to TVR for low-income consumers, specifically, may not be in service of affordability or equity. However, I also note that this study did not investigate energy limiting behavior and thus missed identifying whether this reduction in bills was due to reduced energy use based on unaffordability perceptions. I recommend using the analysis I proposed above, which would be able to correct for the lack of understanding regarding energy limiting behavior and the impact that TVR would have on customers.

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[172] Energy poverty generally refers to a household only being able to reach a level of energy consumption that is insufficient to meet certain basic needs. Energy poverty can also be defined as "the absence of sufficient choice in accessing adequate, affordable, reliable, high-quality, safe and environmentally benign energy services to support economic and human development" (Reddy et al. 2000). Sources: Reddy, A. K., Annecke, W., Blok, K., Bloom, D., Boardman, B., Eberhard, A., & Ramakrishna, J. (2000). Energy and social issues. World energy assessment, 39-60; González-Eguino, M. (2015). Energy poverty: An overview. Renewable and sustainable energy reviews, 47, 377-385.

[173] Energy insecurity is defined as an inability to meet basic household energy needs. See the following papers for more on energy insecurity: Memmott, T., Carley, S., Graff, M., & Konisky, D. M. (2021). Sociodemographic disparities in energy insecurity among low-income households before and during the COVID-19 pandemic. Nature Energy, 6(2), 186-193; Hernández, D. (2016). Understanding 'energy insecurity' and why it matters to health. Social science & medicine, 167, 1-10.

[174] For example, a PG&E TVR pilot found that 90% of low-income customers saw savings under TVR, whereas only 6% were harmed. Opinion Dynamics, 2020: 2020_ACEEE-Summer-Study_Assessing-Equity-How-Low-Income-Customers-Fare-on-TOU_Rates_Folks.pdf

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Recommendations for Time-of-Use (TOU) Rates[175]

1. **Equity Tracking**: TOU rates have the potential to disproportionately affect customers who cannot shift their energy usage. To address this, the Commonwealth should:
    - Track and monitor changes in energy consumption among hyper vulnerable groups. There are a multitude of metrics that can be tracked.[176] Key affordability metrics include energy burdens[177] as well as energy limiting behavior in the summer[178] and winter.[179]
    - Use AMI data to identify at-risk customers and inform them about available bill assistance programs, energy efficiency measures, and other affordability interventions. The strategies for deploying information should make use of multimedia (text messages, in-app messages, and texting) communications which can reach a utility's entire customer base.

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[175] TOU rates are a subset of TVR.
[176] Nock, D., Jones, A. J., Bouzarovski, S., Thomson, H., & Bednar, D. J. (2024). Reducing energy burden in the power sector: Metrics for assessing energy poverty. *IEEE Power and Energy Magazine*, *22*(4), 26-37.
[177] Energy burden is defined as the percent of income a household spends on their energy bills. For an accurate energy burden calculation this calculation should include all energy sources in the home. Hernández, Diana. "Understanding 'energy insecurity' and why it matters to health." Social science & medicine 167 (2016): 1-10.
[178] Here energy limiting behavior is defined as the "inability or unwillingness to consume enough energy to reach a desired level of comfort." This study uses AMI data to identify energy limiting behavior. Cong, S., Nock, D., Qiu, Y. L., & Xing, B. (2022). Unveiling hidden energy poverty using the energy equity gap. *Nature communications*, *13*(1), 2456.
[179] Huang, Luling, Destenie Nock, Shuchen Cong, and Yueming Lucy Qiu. "Inequalities across cooling and heating in households: Energy equity gaps." *Energy Policy* 182 (2023): 113748.

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2. **Identification of Non-Shiftable Loads**: Many households lack large shiftable loads (e.g., air conditioners) or technologies which enable load shifting (e.g., programmable thermostats), making it impractical for them to benefit from TOU rates. For these customers:
    - Employ data-driven methods to identify homes with limited shiftable energy usage, use multimedia approaches to communicate bill reduction opportunities, and be proactive in connecting them to energy assistance.
    - Offer alternative rate structures (e.g., a flat rate) that reduce energy burdens for these households. To gain insights as to how different pricing structures will impact households, I recommend using energy consumption data to analyze historical energy consumption changes following rate increases. This can indicate how TOU pricing and different rate levels will impact energy consumption in residential households. This analysis should be conducted for hyper vulnerable households, and then compared to the broader population to identify potential risks of rate changes.

Conclusion

As electrification progresses and rate structures evolve, it is critical to center equity and affordability in all aspects of ratemaking. AMI data offers an opportunity to identify and address disparities proactively, particularly in hyper vulnerable communities. In addition, carefully designed TVR rates can help mitigate unintended consequences (i.e., high energy burdens, energy limiting behavior) that are the result of high bills. By proactively engaging with vulnerable households and implementing data-driven solutions, stakeholders can ensure that the transition to a cleaner and more efficient energy system is equitable, affordable, and sustainable.

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