MASSACHUSETTS
DEPARTMENT OF ENERGY RESOURCES

Ratemaking Straw Proposal

Massachusetts Electric Rate Task Force (Task Force)

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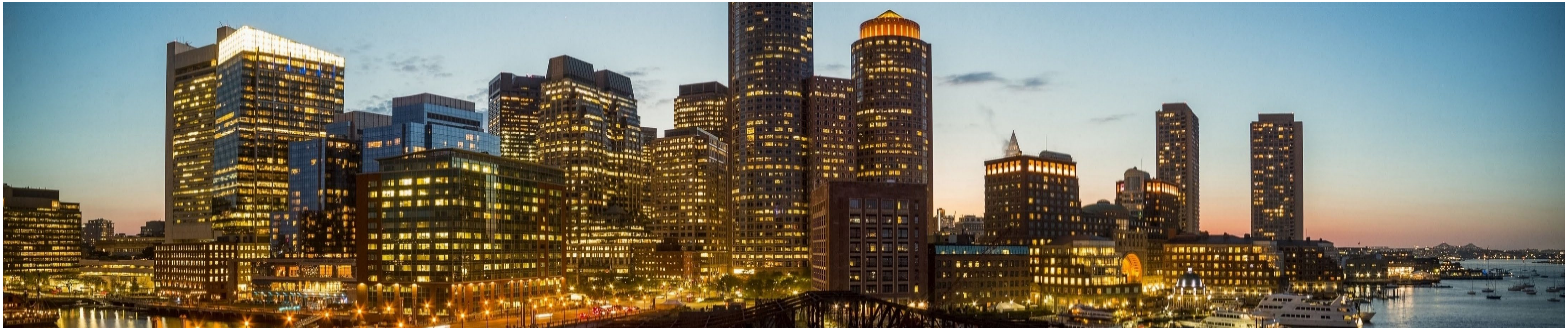
Our Mission

The Department of Energy Resources' (DOER) mission is to create a clean, affordable, resilient, and equitable energy future for all in the Commonwealth.

Who we are: *As the state energy office, DOER is the primary energy policy agency for the Commonwealth. DOER supports the Commonwealth's clean energy goals as part of a comprehensive Administration-wide response to the threat of climate change. DOER focuses on transitioning our energy supply to lower emissions and costs, reducing and shaping energy demand, and improving our energy system infrastructure.*

What we do: *To meet our objectives, DOER connects and collaborates with energy stakeholders to develop effective policy. DOER implements this policy through planning, regulation, and providing funding. DOER provides tools to individuals, organizations, and communities to support their clean energy goals. DOER is committed to transparency and education, supporting the accessible access to energy information and knowledge.*



Agenda

i. Introduction (10 minutes)

ii. Rate design recommendations (55 minutes)

iii. Break (5 minutes)

iv. Regulatory mechanism recommendations (55 minutes)

v. Process and implementation recommendations (20 minutes)

vi. Next steps and closing (5 minutes)

DOER convened the Task Force in early 2025, following the Interagency Rates Working Group's recommendation

Mission statement

The Massachusetts Electric Rate Task Force brings together diverse stakeholders to reimagine how electric rates and the regulatory framework can drive an affordable, equitable, and decarbonized energy future.

Through targeted conversations, expert presentations, and thoughtful exploration of complex issues, the Task Force aims to deepen understanding, surface critical questions, clarify challenges, and build the foundation for durable regulatory reform and action.

Purpose

To facilitate informed and forward-looking dialogue on electric rate design and regulatory mechanisms that advance Massachusetts' decarbonization and affordability goals.

Objective

To build shared understanding of key issues, surface priority and outstanding questions, and prepare a strong foundation for a Department of Public Utilities (DPU) investigation into electric rates and the regulatory framework.

DOER hosted expert sessions and targeted conversations on rate designs, ratemaking, and regulatory mechanisms

By the numbers

27 months of study and stakeholdering, including IRWG

23 sessions hosted for Task Force participants

41 expert presentations on ratemaking topics

256 stakeholders participated in Task Force sessions

68 additional discussions with stakeholders

Build technical knowledge

Provide an opportunity for **knowledge-building** by and amongst stakeholders, including those who have not traditionally been involved

Facilitate open dialogue

Engage in **open, inclusive dialogue** about complex ratemaking and regulatory issues outside of a regulatory proceeding

Develop shared understanding

Converge towards **shared understandings** of the challenges and priorities

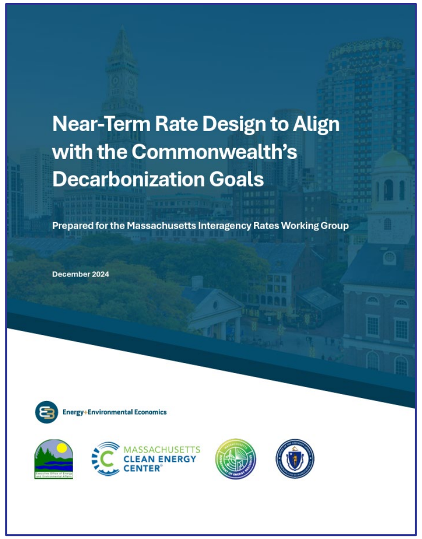
Frame critical questions

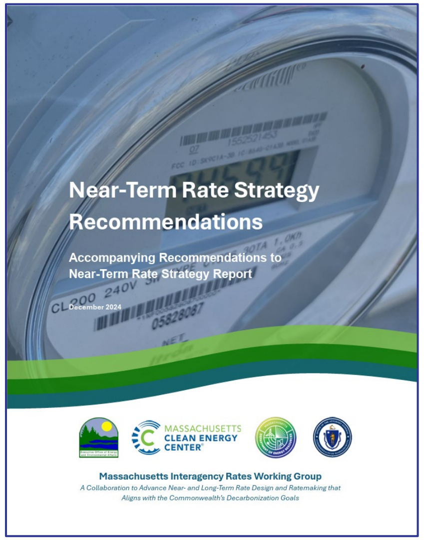
Empower stakeholders to identify **critical questions and opportunities** for the advancement of rate design and ratemaking reform

Task Force built upon study and recommendations from the Massachusetts Interagency Rates Working Group

Near-term study and recommendations

- Near-Term Rate Strategy Report, prepared by Energy & Environmental Economics, Inc. (E3)
- Near-Term Rate Strategy Recommendations, prepared by Interagency Rates Working Group (IRWG)





Long-term study and Recommendations

- Long-Term Ratemaking Study, prepared by E3
- Long-Term Ratemaking Recommendations, prepared by IRWG

Task Force provided opportunity to comprehensively consider regulatory framework

Task Force addressed emergent needs

Massachusetts' energy transition is at an **inflection point and requires a regulatory framework** that drives electrification, supports grid efficiency and flexibility, and promotes cost-effective investments to modernize the electric grid

The regulatory environment must:

- **Prioritize affordability, equity, and decarbonization,** in addition to safety, security, and reliability
- **Encourage electric utilities to develop innovative solutions** to achieve these priorities

Recommendations enable prompt action

DOER's recommendations build on comprehensive examination of existing regulatory framework and extensive stakeholder engagement and provide a foundation for the **DPU to investigate and determine direction on rate design and regulatory mechanisms**

There is a key **window of opportunity over the next few years to consider policy and regulatory reform** prior to:

- advanced meter deployment
- electric utility rate cases
- future energy efficiency plans
- electric sector modernization plans

Rate Design Recommendations

55 min

Implementing time-varying rates is a critical opportunity to promote affordability in Massachusetts

Provide customers greater control over their energy costs through expeditious implementation of time-varying rates by leveraging decades of consideration and evaluation

- In **D.P.U. 09-31, D.P.U. 09-33, and D.P.U. 11-29,** the DPU approved Smart Grid Pilots for each EDC that included time-of-use rates combined with automated load management technologies and marketing, education, and outreach
- In **D.P.U. 12-76**, a stakeholder report provided TVR design recommendations and a DPU straw proposal proposed a TVR investigation guided by specific principles
- In **D.P.U. 14-04**, the DPU investigated the benefits, design, and implementation of TVR under Basic Service and adopted a policy framework
- In **D.P.U. 21-80, D.P.U. 21-81, D.P.U. 21-82,** the DPU pre-authorized advanced metering infrastructure (AMI) investments for all three EDCs
- In **D.P.U. 23-50**, the DPU signaled a future examination of improving the accuracy of price signals sent to basic service customers
- In **D.P.U. 23-84 and D.P.U. 23-85,** the DPU indicated eagerness to initiate critically needed investigations into alternative rate designs that will ease customers' energy burden

Time-of-use rates are an untapped affordability measure

TOU rates can unlock short- and long-term savings

Short-term: Shifting 6% of consumption from peak to off-peak periods could save National Grid's residential customers approximately:[1]

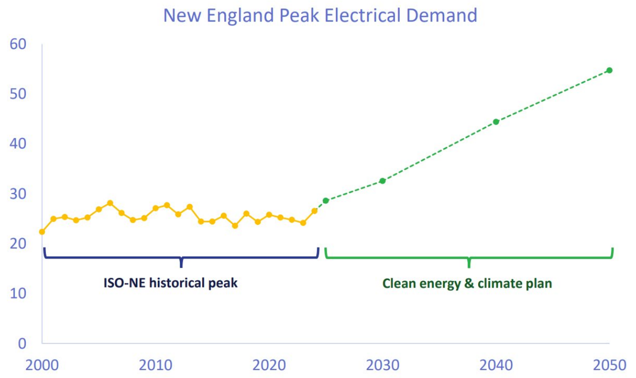
- $31.3 million in transmission costs
- $9.8 million in capacity costs
- $6.6 million in energy costs

Long-term:

- Reduced spending on new infrastructure to accommodate load growth
- If peak demand increases slower than total use (i.e., new load is effectively managed), rate increase will slow

[1]6% peak demand reductions estimated by DOE "Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies" (2016). 6% likely represents a lower bound as more automated load management technologies are and will become available

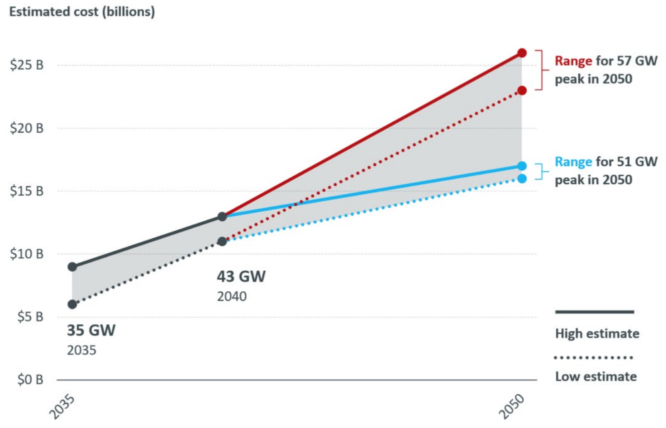
Load growth is essential



Deploying enough EVs and heat pumps to hit CECP targets will increase system peak significantly

Source: Charles Dawson, DOER. Expert Presentation Session on Performance Mechanisms (Nov. 2025), p. 52.

Unmanaged load growth will undermine affordability



ISO-NE estimates **$7-9 billion in new transmission costs** by 2050 if load growth is not managed

Source: ISO-NE, 2050 Transmission Study (Feb. 2024), Figure 2-1, p. 16

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Rate designs should prioritize efficiency, fairness, and equity

Rate designs must evolve with system needs and allow all customers to save

- Efficient rate designs, or price signals, enable customers to promote a least-cost electric system
- Cost studies that identify drivers of incremental system costs ensure that customer classes are properly assigned costs to serve that class
- Rate structures must consider customer affordability and evolving consumer needs
- Simplicity, continuity, and earnings stability remain important principles, but must not delay timely implementation of critical rate design reform
    - Advanced meters and supporting technologies are changing what it means to be easily understood by consumers and increasingly automating consumption patterns

DPU evaluates rate designs by balancing several principles

Principle	Definition
Efficiency	provide accurate basis for consumers' decisions about meeting needs and recovers the societal cost of consumption of resources to produce utility service (i.e., cost-based)
Fairness	each customer class should pay no more than the costs of serving that class
Equity	rate structure considers affordability among customers in establishing rate classes
Continuity	changes to rate structure should be gradual to allow consumers time to adjust their consumption patterns in response to a change in rate structure
Simplicity	easily understood by consumers
Earnings stability	amount a company earns from its rates should not vary significantly over a period of one or two year

Rate design should be more flexible and responsive to evolving system and consumer needs

Driving affordability through coordinated rates and programs

- Rates, as price signals, and programs that help incentivize technologies and behavior can each support a least-cost system in distinct manners
- Reevaluating rate design for efficiency, fairness, and equity enabled by AMI ensures programs are efficiently targeting system needs
- Broad-based rate designs, such as time-of-use rates, can support avoidable or deferrable costs to the bulk system, while programs may be better suited to capture local distribution system benefits

Changes in rate design will have impact on existing programs that will evolve to meet customer needs

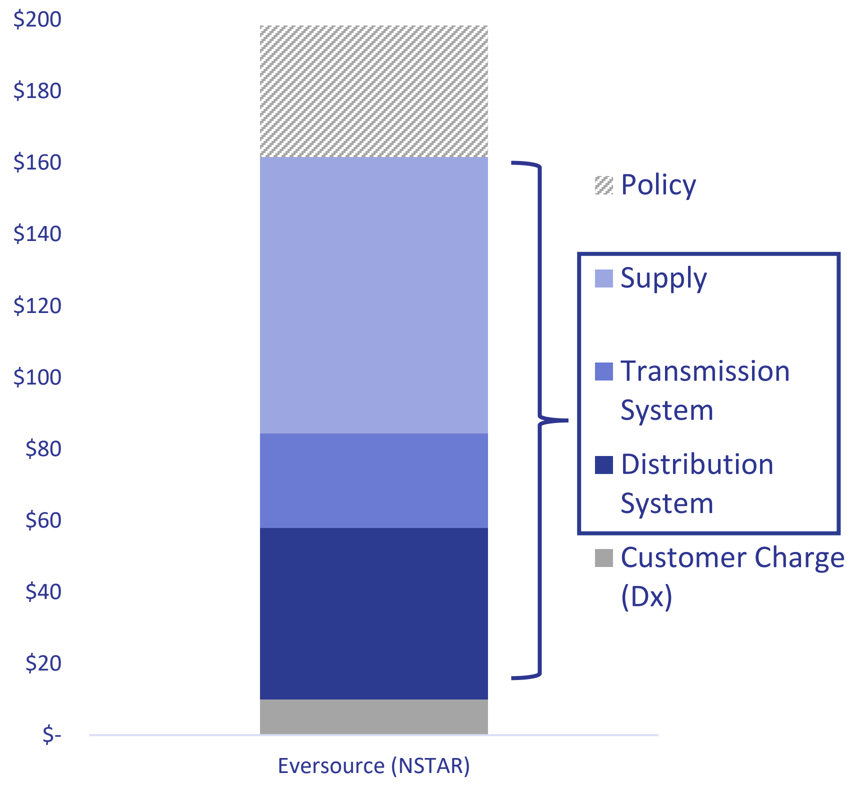
- Existing clean energy programs will need to be responsive to or coordinate with TOU roll-out, including:
    - Clean Peak Energy Standard
    - Solar Massachusetts Renewable Target
    - Net Metering
    - EV Managed Charging
    - Connected Solutions
- Clean energy policies and programs will evolve during and after implementation of ratemaking changes

See: Expert Presentation, Alternative Rate Design (June 9, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025); Expert Presentation, Bill and Distributed Energy Resources Impacts (June 30, 2025); Targeted Conversation, Bill and Distributed Energy Resources Impacts (July 9, 2025)

Design a single, consolidated TOU peak period across supply, distribution, and transmission

A single consolidated peak period will provide customers with a simple price signal that will maximize beneficial load-shifting behavior

- **Supply** costs reflect the price of generating electricity, which varies based on the time of day and season driven by demand of electricity and available supply resources; variability expected to grow as additional renewable generation is deployed
- **Transmission and distribution** costs are driven by peak demands, such that consumption during peaks necessitate costly investments in infrastructure; consumption off-peak has minimal incremental cost to system
- A **single consolidated peak period will provide customers with a clear price signal** that will maximize beneficial load-shifting behavior
- TOU for supply, distribution, and transmission empowers customers to have more control over approximately 80% of their bill, **increasing the potential for customer savings**
- A distribution TOU rate based on supply peak periods will not capture every local distribution peak; however, providing a clear price signal that is easy to follow and customer-centric will support beneficial customer responses, likely outweighing any granularity provided with multiple peak periods



See: Expert Presentation, Time of Use Rate Design (May 19, 2025); Targeted Conversation, Time of Use Rate Design (May 28, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025);

Key rate components and processes for setting them

	Cost component	Procedure
Supply	Energy	• Customers may receive supply from Basic Service, municipal aggregation, or competitive suppliers • DPU does not review or approve supply rates for municipal aggregation or competitive supplier products • DPU biannually reviews and approves residential Basic Service rates determined by EDCs competitive power procurement
	Capacity	
Delivery	Transmission – Regional Network Services (RNS)	• EDCs annually file transmission rates with DPU to fully recover transmission service costs for customers
	Distribution	• EDCs proposed new rates and the DPU reviews and approves rates in a rate case, at least every five years

See: Expert Presentation, Time of Use Rate Design (May 19, 2025); Targeted Conversation, Time of Use Rate Design (May 28, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025);

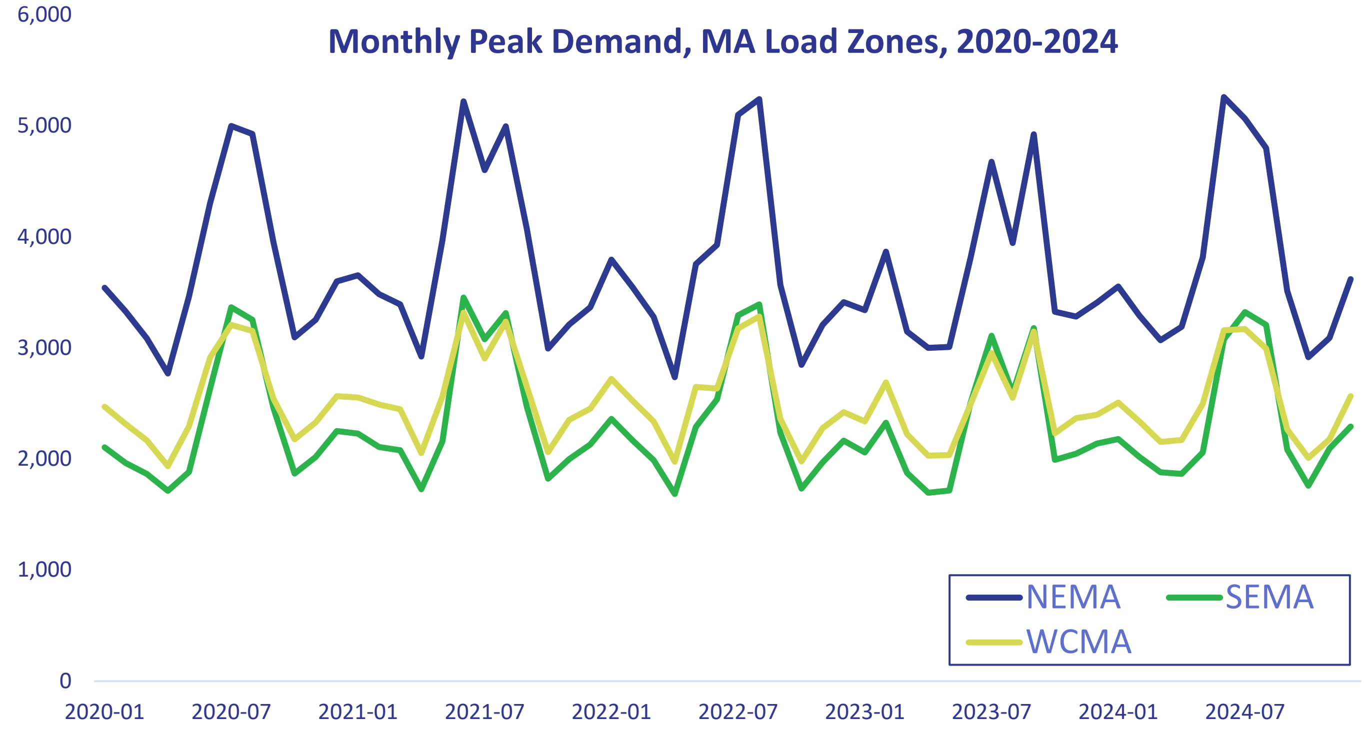
Allocate bill components to TOU periods based on cost causation/allocation

Cost component	TOU period allocation	Rationale
Energy	Peak and off-peak rates reflect wholesale prices	• Give customers opportunity to save on energy by aligning consumption with cheaper market prices but without direct exposure to volatile real-time market
Capacity	Allocated entirely to summer peak hours	• Capacity costs are allocated based on demand during annual system peak • Sending price signal to reduce consumption during hours when the annual peak is likely to occur will reduce residential capacity costs
Transmission – Regional Network Services (RNS)	Allocated to peak hours in all months	• Transmission RNS costs are allocated based on demand during monthly peaks • Sending price signal to reduce consumption during hours when monthly peaks are likely to occur will reduce residential transmission costs
Distribution	Marginal costs are allocated to peaks based on MCOS study	• Increased load, especially from electrification, could necessitate expensive distribution upgrades • Sending price signal to reduce consumption during hours when distribution level peaks are likely to occur will reduce future residential distribution costs.

See: Expert Presentation, Time of Use Rate Design (May 19, 2025); Targeted Conversation, Time of Use Rate Design (May 28, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025);

Differentiate TOU rates by season

Annual peaks occur during between June and September. These months should comprise a peak “summer season”



Count of Annual Peaks by Month, 2020-2024

Month	System	NEMA	SEMA	WCMA
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	1	2	1	1
7	2	1	2	2
8	1	1	1	1
9	1	1	1	1
10	0	0	0	0
11	0	0	0	0
12	0	0	0	0

Source: ISO NE, Hourly SMD Data, https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

See: Expert Presentation, Time of Use Rate Design (May 19, 2025); Targeted Conversation, Time of Use Rate Design (May 28, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025);

Considerations for selecting the daily peak period

The daily peak period should be long enough to reliably capture cost drivers…

Timing of system cost drivers

- **Annual system peaks** - capacity cost allocation, need to invest in new grid infrastructure
- **Monthly system peaks** - regional transmission cost allocation
- **Daily peaks** - correlate with energy prices and distribution system costs

…But short enough for customers to shift consumption to the off-peak period

- Other jurisdictions are implementing three- to five-hour periods

	Summer peak period	Peak to off-peak differential
Maine (proposed)	3-8pm	>2:1
Michigan	3-7pm	1.33:1
Long Island	3-7pm	2.2:1
California (SMUD)	5-8pm	2.43:1 / 1.76:1 (off/super off-peak)
Colorado (Excel)	5-9pm	2.05:1
Belmont Light (opt-in)	2-7pm	3.76:1

See: Expert Presentation, Time of Use Rate Design (May 19, 2025); Targeted Conversation, Time of Use Rate Design (May 28, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025);

Establish a daily peak period that captures cost drivers

Comparing all reasonable peak windows, DOER recommends a 5-hour peak period from 3-8pm on non-holiday weekdays

1. Annual system peaks are how capacity costs are allocated

2. Monthly load zone peaks are how transmission costs are allocated

3. Daily peaks relate to energy and distribution system costs

		1 % of Annual Peaks Captured				2 % of Monthly Peaks Captured			3 % of Daily Peaks Captured		
Peak Length	Hours	ISO-NE System	NEMA	SEMA	WCMA	NEMA	SEMA	WCMA	NEMA	SEMA	WCMA
3	16-18	100%	80%	100%	60%	75%	60%	53%	55%	40%	38%
3	17-19	80%	40%	100%	100%	75%	93%	87%	71%	74%	74%
4	16-19	100%	80%	100%	100%	88%	93%	88%	74%	75%	74%
5	16-20	100%	80%	100%	100%	88%	98%	92%	84%	91%	87%
5	17-21	100%	40%	100%	100%	75%	98%	90%	86%	96%	93%
6	14-19	100%	100%	100%	100%	92%	93%	92%	77%	76%	76%
6	15-20	100%	80%	100%	100%	90%	98%	93%	85%	91%	88%
7	14-20	100%	100%	100%	100%	92%	98%	95%	87%	92%	88%

ISO NE, Hourly SMD Data, https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

Why a 5-hour peak from 3-8pm?

- 3-hour does not reliably capture annual, monthly, or daily peaks
- 4-hour captures most annual and monthly peaks, but misses a quarter of daily peaks
- 5-hour captures 100% of annual peaks, most monthly peaks, and 10-16% more daily peaks than 4-hour
- 6- and 7-hour barely capture more cost-driving hours than 5-hour, and the longer window reduces customer opportunities to shift consumption from peak to off-peak hours

See: Expert Presentation, Time of Use Rate Design (May 19, 2025); Targeted Conversation, Time of Use Rate Design (May 28, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025);

Incorporate flexibility from the beginning

TOU rate design should adapt to system conditions, while maximizing customer understanding

The timing and level of capacity, energy, transmission, and marginal distribution costs may change over time

- **TOU rates should not preclude future rate reforms**, particularly those enabled by the proliferation of electrified loads (EVs, HPs) and automated load management solution - e.g., critical peak pricing, demand changes, etc.

Incrementally adjust peak period timing and season definitions to reflect cost drivers (e.g., peak shifts 3-8pm → 4-9pm)

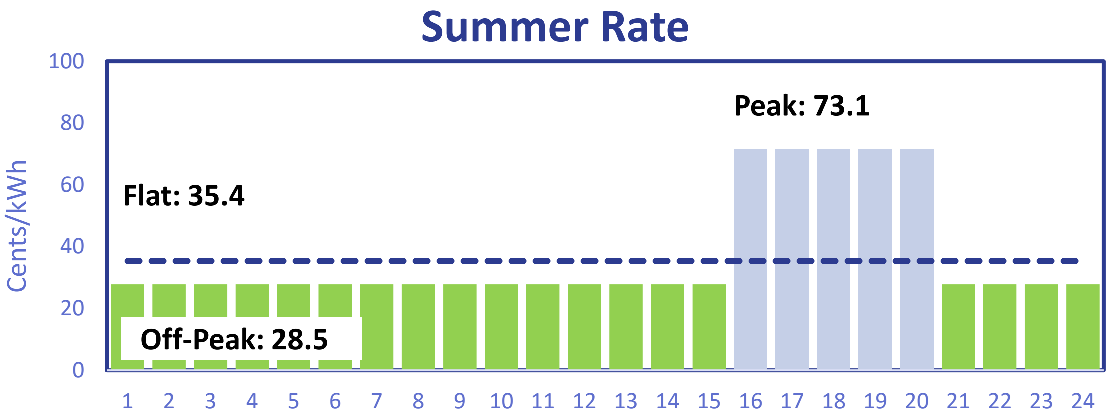
- Harmonize changes for all utilities without waiting for rate cases
- Plan for shift from summer to winter peaking (post 2035)

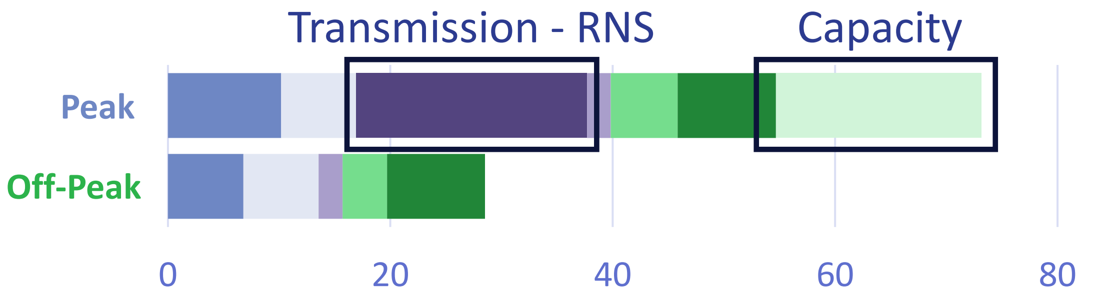
Incrementally adjust rate levels to reflect costs

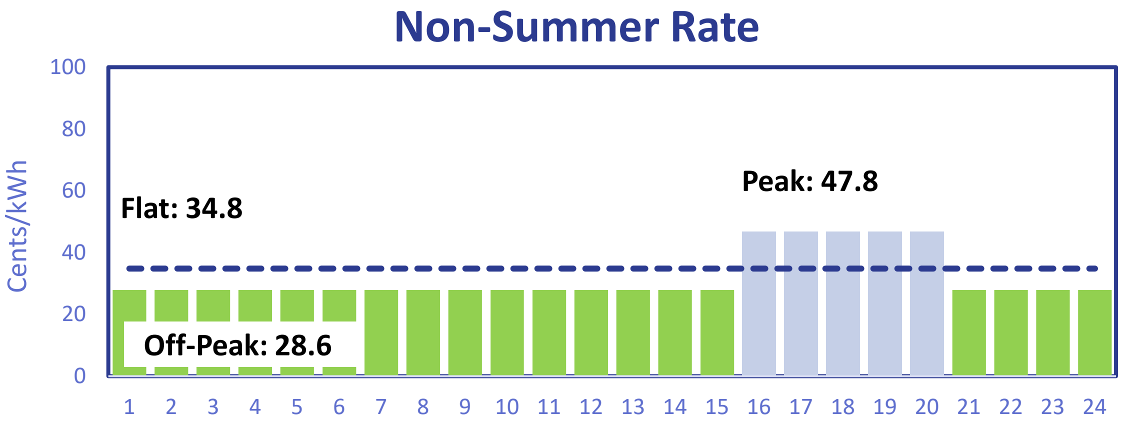
- Energy, capacity, and transmission service based on wholesale market prices – retail prices adjust for customers outside of rate cases
- Distribution rates based on marginal cost study and time-of-use analysis – adjust peak to off-peak ratio in rate cases as appropriate

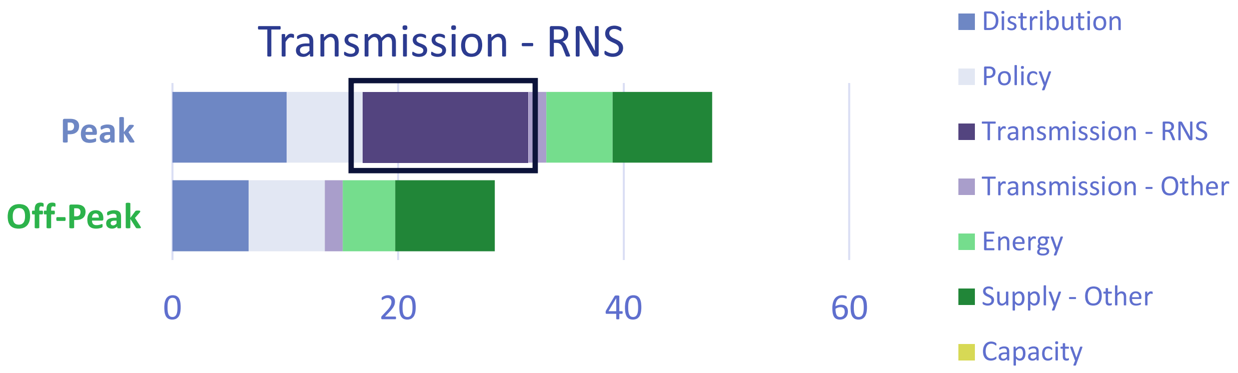
Illustrative TOU rate

Applying the proposed TOU design methodology to National Grid (2025)









*This illustrative example has a 1:1.5 peak ratio for distribution costs. In practice, this differential can be identified via a marginal cost of service study

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Additional implementation considerations

TOU rates for customers will be implemented in phases

- Customers experience total peak and off-peak rates and total peak to off-peak ratio
- TOU rate implementation will be incremental for most customers as different components are time-varied in sequence

Supply	→	Transmission	→	Distribution
Basic service filing or third-party supply contracts (e.g., municipal aggregation		Reconciliation mechanism filing		Rate case

Suppliers will price energy, capacity, ancillary services, and other costs based on rate structure or design parameters

- Implementing TOU rates in which capacity costs are allocated to summer peak periods will require creative solutions for compensating suppliers, who are billed for capacity by ISO-NE monthly, whereas those bills are based on the previous year's annual peak consumption
- ISO-NE is exploring a seasonal capacity market, where capacity costs are allocated based on summer and winter peak usage, not just summer
  - The TOU rate capacity cost allocation can be adjusted to reflect capacity market changes

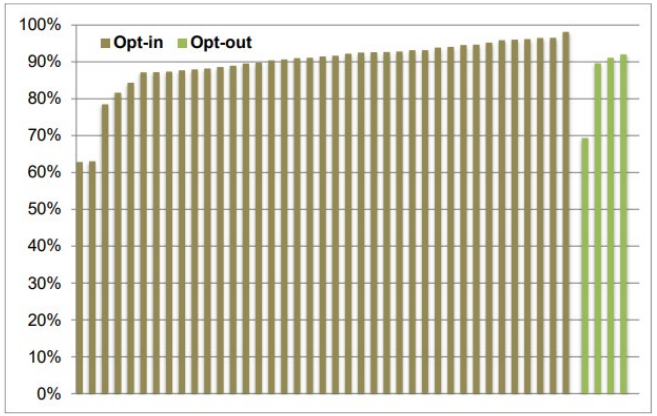
Automatically enroll all residential customers on TOU rates

DPU previously supported default TOU for Basic Service, recognizing the ample evidence of the benefits of default enrollment, including to low-income customers

- **Default TOU can significantly increase enrollment, and therefore benefits,** compared to opt-in (DOE Consumer Behavior Studies), maximizing the total load that is exposed to price signals for load management (Long-Term Ratemaking Study at 41-42). **Retention rates are similar after 1 year**.
- In general, IOU opt-in TOU programs across the country see participation from fewer than half of 1% of residential customers (MPUC Exeter Report).
- Maine, Michigan, Long Island, and major utilities in California and Colorado, have or will be implementing default opt-out TOU rates.
- **DPU supported a default TOU rate for Basic Service** to maximize benefits to customers, including to low-income customers (D.P.U. 14-04-C Order).

Table 5. SMUD Cost Effectiveness Analysis Results[37]

Recruitment Approach	Scenario Offer	Benefit-Cost Ratio
Opt-in	TOU, no IHD	1.19
	TOU, with IHD	0.74
	CPP, no IHD	2.05
	CPP, with IHD	1.30
Opt-Out	TOU, with IHD	2.04
	CPP, with IHD	2.22
	TOU-CPP, with IHD	2.49



Retention rates after 1 year for opt-in and opt-out by treatment group within utility study

Source: Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, US DOE, November 2016

See: Expert Presentation, Implementation & Protections (July 21, 2025); Targeted Conversation, Implementation & Protections (July 30, 2025)

Allow low-income customers to opt-out

Stakeholders expressed concern around impacts to low-income customers during a period of heightened concern for energy affordability

- Evidence from other jurisdictions suggests that most low-income customers experienced bill savings under default TOU rates (Opinion Dynamics, 2020) indicating **that a categorical delay or even opt-in approach for low-income customers may undermine affordability and equity.**
- However, in response to stakeholder concerns and to minimize harm to low-income customers during a period of heightened concern for energy affordability, **DOER recommends the DPU allow qualified low-income customers to opt-out of TOU rates.**
  - Low-income customers will be further protected from bill increases if enrolled on the **low-income discount rate and if DPU expands tiered discount rates** in 24-15.
  - Additional bill protection recommendations are covered in a future slide.

PG&E Default TOU Pilot: Actual bill impact by low-income program participation status

	Achieved Bill Impact		
	Benefiter	Neutral	Non-benefiter
Low-income	90%	4%	6%
Non-low-income	59%	9%	32%

Low-income customers are defined as those enrolled in the California Alternate Rates for Energy/Family Electric Rate Assistance (CARE/FERA) programs. Recent research found that 90% of eligible customers participate in CARE (Opinion Dynamics and DNV GL 2019). Note that CARE/FERA customers residing in hot climate zones were excluded from the default pilot. As such, the analysis presented here excludes non-CARE/FERA customers from hot climate zones for comparison validity purposes. Customers received bill protection, where they received a bill credit at the end of the first year on the TOU rate if they experienced a net loss (exceeding $5 for low-income customers, exceeding $10 for non-low-income customers). Non-low-income customer bill impacts used +/- $10 as the threshold for benefiter/neutral/non-benefiter status.

Source: Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, US DOE, November 2016

See: Expert Presentation, Implementation & Protections (July 21, 2025); Targeted Conversation, Implementation & Protections (July 30, 2025)

Offer additional bill protections for low-income customers, such as shadow billing

Shadow billing, in conjunction with the ability to opt-out, should provide low-income customers with the information needed to reduce their energy burden

- Low-income customers will be protected through the low-income discount rate (which the DPU may expand into tiered discount rates in 24-15), as well as the ability to opt-out of TOU rates.
- In addition, DOER recommends that **shadow billing be provided to all low-income customers for a period of one year** following enrollment on TOU rates to help them determine whether opting out will reduce their energy burden.
- DOER also recommends the **EDCs analyze the impacts of bill stabilization for all low-income customers for a period of one year.**
    - Bill stabilization can be a valuable tool to minimize harm to low-income customers. However, if low-income customers can opt-out of TOU rates at any time, bill stabilization may be less helpful and could even be harmful to other customers.
    - Bill stabilization could result in customers in other rate classes subsidizing those that receive bill stabilization, thereby raising the former’s bills and reducing the effectiveness of TOU rates. Therefore, before implementing bill stabilization, benefits and costs of such a measure should be analyzed.

See: Expert Presentation, Implementation & Protections (July 21, 2025); Targeted Conversation, Implementation & Protections (July 30, 2025)

Leverage AMI data to protect customers

AMI data enables EDCs to monitor customer load profile changes to identify risks and intervention opportunities

- EDCs can analyze AMI data to:
  - **Monitor energy limiting behavior** to identify impacts to affordability and inform targeted protections
  - **Identify non-shiftable loads** (e.g., medical devices) and protect households if TOU rates increase energy burden
  - **Target affordable access to enabling technology** to low-income households that will benefit
  - **Identify other customers experiencing undue energy burden**
- The 2024 Climate Act directed the EDCs to jointly establish a centralized AMI data repository that will enable tracking the impacts of new rates on low-income customers across EDCs
  - The Department has directed the EDCs to file plans for this repository in D.P.U. 26-20, 26-21, and 26-22 by February 18, 2026

See: Expert Presentation, Implementation & Protections (July 21, 2025); Targeted Conversation, Implementation & Protections (July 30, 2025)

Strategic implementation and enrollment should minimize adverse customer experience

The following principles should guide implementation and enrollment in a timely manner, sequenced to minimize customer bill impacts

1. Consider customer bill impacts when sequencing the transition to minimize harm and provide shadow billing ahead of implementation to allow customers time to adjust energy usage to new rate
2. Consider geography when sequencing the transition to better target marketing, education, and outreach
3. Operational feasibility and quality control should drive the maximum number of customers transitioned each month
4. Consider appropriate timing of implementation to avoid transitioning customers during periods when customer bills are more volatile (e.g., peak summer/winter)
5. Coordinate with municipal aggregations that are interested in offering TVR for supply
6. Enrollment of all residential customers should be expeditious and include degree of flexibility to adjust to new circumstances, allow time to resolve mistakes, and implement lessons learned

See: Expert Presentation, Implementation & Protections (July 21, 2025); Targeted Conversation, Implementation & Protections (July 30, 2025); Expert Presentation, Marketing, Education, and Outreach (August 4, 2025); Targeted Conversation, Marketing, Education, and Outreach (August 13, 2025);

EDCs should jointly develop an implementation and marketing, education, and outreach plan with stakeholders

Task Force and IRWG provide ample MEO principles that should guide development of efforts

- Drawing on robust experience with MEO plans (e.g., for Mass Save 3-Year Plans) and customers, **EDCs should jointly develop an implementation and MEO plan** in coordination with stakeholders
  - Stakeholders should include ratepayers, MEO professionals, low-income advocates, community groups, aggregators, suppliers, and other stakeholders
  - Stakeholders should work with the EDCs to identify MEO strategies and data-analytic tools to create a comprehensive, targeted plan that communicates the benefits of TOU rates
- **Implementation and MEO planning should not delay implementation of TOU rates**
  - EDCs should plan for implementation and MEO ahead of DPU decision on rate designs and coordinate with stakeholders concurrently to design and development of rates to allow for EDCs to initiate MEO at least 90 days before TOU implementation

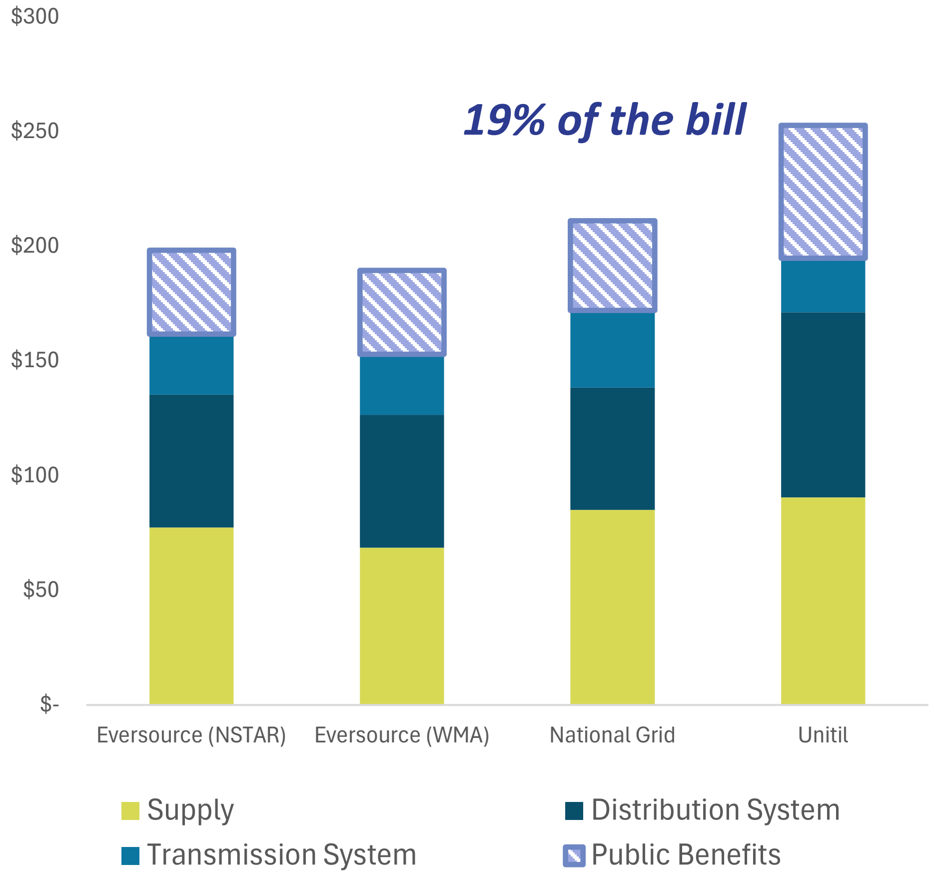
MEO Principles

- Customer-centric
- Simple
- Cost-effective
- Targeted
- Plain language
- Multi-cultural
- Community collaboration
- Variety of channels
- Use KPI
- Track metrics

See: Expert Presentation, Implementation & Protections (July 21, 2025); Targeted Conversation, Implementation & Protections (July 30, 2025); Expert Presentation, Marketing, Education, and Outreach (August 4, 2025); Targeted Conversation, Marketing, Education, and Outreach (August 13, 2025); IRWG Long-Term Ratemaking Recommendations (March 2025)

Recover key public benefits programs as non-bypassable fixed charges

Recovering specific public benefits costs via a fixed charge reduces seasonal bill shocks, improves cost-reflectivity, and reduces volumetric rates



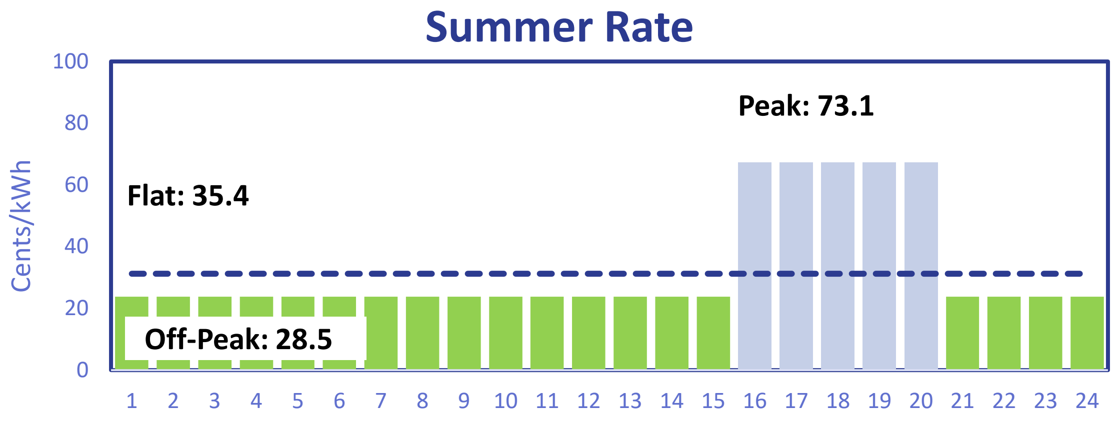
Recommendation: Convert the energy efficiency reconciliation factor (EERF) and residential assistance adjustment factor (RAAF) to fixed charges ($16-18 and $5-7, respectively).

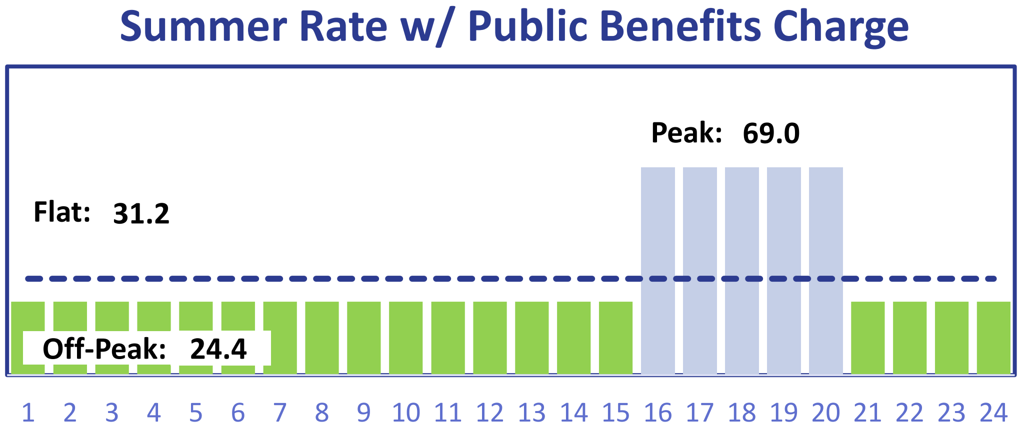
- **Public benefits costs represent ~$40 on the average customer bill** and are recovered entirely through a volumetric charge, which
  - Increases seasonal bill volatility
  - Discourages electrification and, for some vulnerable customers, safe/healthy levels of consumption
  - Enables customers with solar and energy efficiency to avoid contributing
- The Long-Term Ratemaking Study finds that increasing the **fixed charge by $30/month enables cost competitive electrification**, also supported by time-varying supply, transmission, and distribution

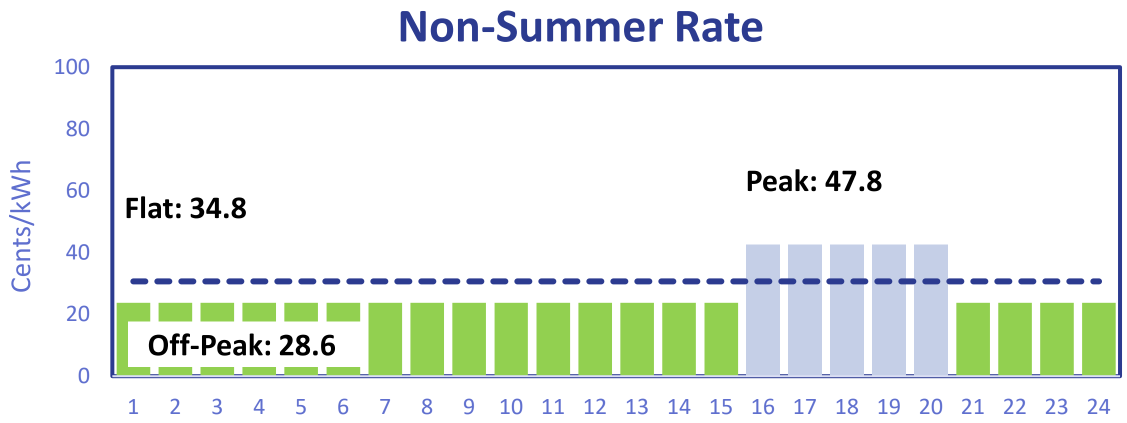
See: Expert Presentation, Alternative Rate Design (June 9, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025)

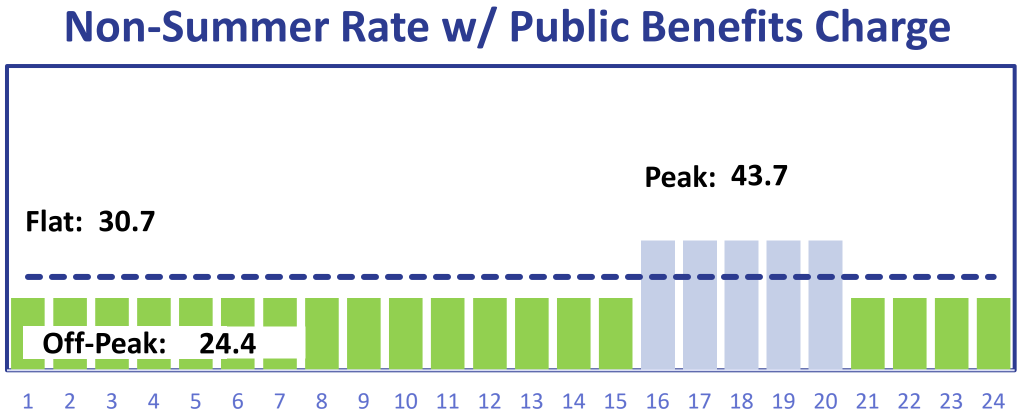
TOU and public benefits charge promote affordability and electrification

Public benefits charges support more cost-reflective off-peak prices that promote efficient electricity consumption









See: Expert Presentation, Alternative Rate Design (June 9, 2025); Targeted Conversation, Alternative Rate Design (June 18, 2025)

Regulatory Mechanism Recommendations

55 min

Transition several reconciling mechanisms into base distribution rates or otherwise eliminate tariff

Growing dependence on reconciling mechanisms has inflated rates and distorted utility incentives

- Reconciling mechanisms:
  - Reduce cost efficiency incentive for EDC
  - Shift risk from EDCs to ratepayers
  - Erode regulatory lag
  - Silo cost recovery and planning
- A transition to base rates through establishing a representative level encourages disciplined operational spending
- Higher electricity rates distorts efficient electricity consumption by reducing the value of electrification
- Reconciling mechanisms must be reserved for electric service components (e.g., transmission, supply service of last resort), extraordinary cost categories, or clean energy and public benefits programs

Reconciling mechanism	Recommendation
Pension adjustment	Transition into base rates – in progress
Vegetation management	Transition into base rates – in progress
Solar programs cost adjustment	Transition into base rates – in progress
Capital cost adjustment	Transition into base rates – in progress
Tax credit factor	Transition into base rates
Electronic payment recovery	Transition into base rates
Attorney general consulting expense	Transition into base rates
Grid modernization	Transition into base rates
Advanced metering infrastructure	Transition into base rates
Provisional system plan	Transition into base rates
Electric vehicle program	Transition into base rates
Infrastructure, safety, reliability, and electrification	Transition into base rates
Electric sector modernization plan	Transition into base rates
Revenue decoupling	Eliminate
Exogenous costs	Eliminate

See: Targeted Conversation, Alternative Rate Design (June 18, 2025); Expert Presentation, Tools of Utility Regulation (September 8, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025)

Reconciling mechanism	Rationale for transitioning into base rates or eliminating
Pension adjustment	Though EDCs don't control market conditions, pension expenses represent a minimal component of cost to serve and separate mechanism not warranted
Vegetation management	Vegetation management is an essential component of utility providing safe and reliable service at least cost, establishing representative cost level in rate case supports EDCs' incentive to seek out cost-efficient approaches
Solar programs cost adjustment	Each applicable EDC will have made eligible investments by its next rate case and representative costs and revenues can reasonably be established
Capital cost adjustment (Unitil)	Capital cost adjustment no longer used to support Unitil's incremental investments between rate cases
Tax credit factor	Other ratemaking and accounting approaches able to adequately resolve outstanding balance of excess accumulated deferred income taxes
Electronic payment recovery	Providing customers fee free credit/debit card payment options is an evolving customer service obligation, reasonable to identify a representative cost level in rate case
Attorney general consulting expense	Consultants support ratepayer interests through DPU proceedings; minimal part of utilities cost to serve and establishing representative cost level in rate case is reasonable, further incentivizes utilities to proactively engage with AGO ahead of proceedings
Grid modernization	Each EDC will have made all eligible investments by its next rate case and costs should be rolled into base distribution rate
Advanced metering infrastructure	Each EDC will have made all eligible investments by its next rate case and costs should be rolled into base distribution rate
Provisional system plan	Establishment of export tariffs provides cost allocation framework for transitioning representative expenses and revenues into base rates, also forthcoming Long-Term System Planning Program expected to replace provisional system plan
Electric vehicle program	Discontinuing revenue decoupling will incentive each EDC to deploy investments to increase revenues associated with vehicle electrification without dedicated funds from all customers
Infrastructure, safety, reliability, and electrification	By the next rate case, National Grid will have the opportunity to roll eligible investments into rate base; discontinuing revenue decoupling and implementation of future test year will support additional investments
Electric sector modernization plan	Discontinuing revenue decoupling and implementation of future test year will enable the EDCs to support investments identified in the ESMPs
Revenue decoupling (eliminate)	Discontinuing revenue decoupling would result in eliminating revenue decoupling tariff and associated reconciling mechanism
Exogenous costs (eliminate)	Discontinuing revenue-cap formula would result in eliminating performance-based revenue tariff and associated exogenous cost reconciling mechanism

Transitioning or eliminating reconciling mechanisms will need to be implemented in a base distribution rate case

Current portfolio of reconciling mechanisms undermines cost transparency and accountability

- Rate cases provide the DPU and intervenors a critical opportunity to examine every aspect of EDC's cost of service; protecting ratepayer interests amidst widespread concerns of affordability and ensuring rates are just and reasonable
- Reconciling mechanisms were deployed to reduce issue-specific rate cases for volatile and large fluctuations in cost categories (e.g., fuel costs), allowing EDCs to recover costs outside of rate cases
    - Current volume of reconciling mechanisms is administratively burdensome and requires substantial resources for dozens of annual proceedings without full protections of a rate case to scrutinize costs comprehensively

Proactively addressing reconciling mechanisms minimizes uncertainty of transition in rate case

- EDCs must demonstrate continued recovery of costs through reconciling mechanism is warranted in base distribution rate proceedings
- DPU can evaluate the use of reconciling mechanisms, determine reasonable approach, and provide guidance to the EDCs outside of, and before, a rate case (e.g., D.P.U. 12-126)
- DOER recommends the DPU find the continuation of several reconciling mechanism no longer warranted
- A base distribution rate case is the appropriate proceeding to implement guidance and transition reconciling mechanism into base distribution rates

See: Expert Presentation, Tools of Utility Regulation (September 8, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025)

Continued use of reconciling mechanisms or other charges

Some reconciling mechanisms are core to providing electric power service to customers

- **Transmission service costs** are passed through to retail customers by distribution companies
- **Transition cost adjustments** function to recover actual costs associated with stranded investments because of electric utility restructuring
- **Basic service adjustments** function to support incremental over- or under-recovery of the power purchase costs; vast majority of power costs recovered through basic service rates; however, reasonable to recover incremental costs from all ratepayers given role in providing service of last resort to all customers
- **Storm cost factors** may reduce discipline and cost-efficiency of storm recovery, though increase frequency and severity of storms may justify extraordinary treatment

Continued support for clean energy and public benefits programs

- All EDCs use reconciling mechanisms pursuant to statutory authority to recover costs, which DPU reviews and approves:
  - **distributed solar** (i.e., state solar-incentive program, SMART)
  - **net metering**
  - **long-term renewable energy contracts**
- All EDCs ratepayers pay two non-reconciling charges established in statute (c. 25, §§ 19-20):
  - **energy efficiency system benefits charge** ($0.00250/kWh)
  - **renewables charge** ($0.00050/kWh)
- As noted, DOER recommends two public benefits program costs be recovered through non-bypassable fixed charges
  - **Energy efficiency reconciliation**
  - **Residential assistance** (e.g., low-income discount rates)

See: Expert Presentation, Tools of Utility Regulation (September 8, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025)

Review and update marginal cost study guidelines and reinstitute filing requirement for future rate cases

Marginal cost studies promote efficiency, fairness, equity, and reliability

- Growth in load- and DER-driven investments justifies reintroduction of marginal cost studies for EDCs
  - **Promote efficient import and export** through rate structures that provide cost-reflective signals to inform consumption decisions, which can defer or avoid costly expansion of grid
  - **Fair and equitable allocation of costs** to consumer driving incremental system costs (e.g., new large loads)
  - **Support reliability at least-costs** by informing valuation of flexibility and grid services
- DPU paused marginal cost study requirement for EDCs in 2019, but previously provided methodological guidelines (see, e.g., D.T.E. 02-24/25, D.T.E. 03-40, D.T.E. 05-27)

Design export tariff for grid-connected resources to fairly allocate costs to DER customers

- Distributed energy resources (DERs) can support an efficient and resilient distribution system, and must be included in the EDCs' distribution system planning
- Direct EDCs to develop export tariff for grid-connected resources; marginal cost study should inform granular, temporal cost-based pricing of exports
- Export tariffs provide price signals to promote efficient DER dispatch, or optimize export behavior, to support grid needs
  - Exports should be incentivized when it benefits grid (e.g., reduces need for system upgrade) and discouraged when it would cause costs (e.g., times with low net load)
- Export tariffs also encourage flexible interconnection (i.e., non-firm export capacity service)

See: Expert Presentation, Time of Use Rate Design (May 19, 2025); Expert Presentation, Alternative Rate Design (June 9, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025)

Discontinue revenue-cap formulas and stay-out provisions

Incentivize utilities to address revenue attrition without customers bearing the burden of revenue-cap formulas

- Revenue-cap formulas, and other alternative regulation, were implemented to address revenue attrition associated with utility costs outpacing revenues
  - Typically referred to as performance-based ratemaking plans in Massachusetts, based on index-based formula (i.e., inflation less productivity growth, I-X), and has also included a consumer dividend, exogenous cost mechanism, and earning sharing mechanism
- Revenue-cap formulas evolved to replace capital cost recovery mechanisms, also designed to address revenue attrition between rate cases during periods of slow sales growth
  - No longer justified following the discontinuation of revenue decoupling, in which revenue attrition is the burden of the EDCs and not ratepayers

Revenue-cap formulas and stay-out provisions don’t adequately protect ratepayers

- Revenue-cap formulas provide annual revenue adjustments over a stay-out period of typically five years, increasing customers’ electricity rates without full regulatory oversight of a rate case
  - Performance is said to be maintained through metrics though revenues have grown substantially without demonstrable benefit to ratepayers
- Five-year stay-out provisions prevent timely updates to costs studies and rate design needed in a rapidly evolving system
- Significant resources expended during rate cases by EDCs, DPU, and intervenors, in addition to resources required between rate cases despite the promise of streamlined ratemaking and reduced administrative burden
  - Reduced administrative burden is not valuable, and not in best interest of ratepayers if it comes at the cost of reduced regulatory oversight and accountability
- Uncertainty in indices and compounding revenue growth over several years heightens risk to ratepayers, erodes regulatory lag, and effectively affords future test year approach over multiple years

See: Expert Presentation, Multi-Year and Formula-Based Rates (September 29, 2025); Targeted Conversation, Multi-Year and Formula-Based Rates (October 8, 2025)

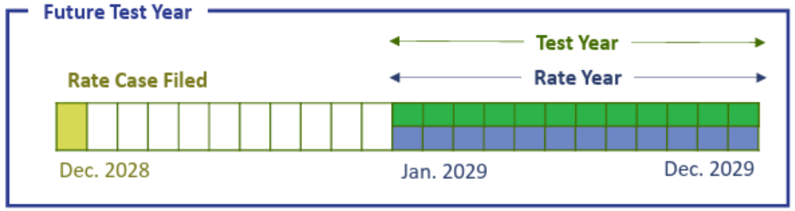
Implement a carefully designed future test year that better serves customers than existing attrition relief mechanisms

Addressing cost growth through a revenue-cap formula based on an historical test year

- Test years are meant to correlate revenues, expenses, and rate base over a period; meant to represent EDCs' present financial situation
- Revenue-cap formulas were introduced to remedy revenue attrition, in part, because of the use of a historical test year
- Intended to resolve longer rate case cycle; however, formula operates, and increases rates, outside of full scrutiny of litigated rate case, resulting in:
  - **Less transparency** from annual revenue changes driven by formula rather than litigated cost review
  - **More spending outside of base rates** through additional reconciling mechanisms or other revenue attrition mechanisms used to support capital investments
  - **Long, blunt forecast horizon** through stay-out period; formula represents cost increase expectations out at least five years without litigated cost or contemporaneous prudency review

Implementing a future test year (FTY) recognizes known and measurable revenue attrition

- During periods of investment growth or high inflation, historical test years won't adequately represent EDC's financial situation, typically resulting in the approval of attrition relief mechanisms
- FTYs based on EDCs' rate year better correlates rates with contemporaneous expenses
  - FTYs reduce regulatory lag, but enables the discontinuation of attrition relief mechanisms (e.g., revenue-cap formula, capital trackers, K-bar, etc.) that similarly erode regulatory lag and lack rigorous customer protections
  - For example, a revenue-cap formula annually compounds cost adjustments out through years with increasingly uncertain costs, while a future test year limits the prospective costs to one year beyond DPU approval of rates



See: Expert Presentation, Tools of Utility Regulation (September 8, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025)

Future test years are step change in Massachusetts ratemaking, but known risks and concerns can be mitigated

Addressing cost growth through a revenue-cap formula based on an historical test year

- DPU is permitted to use a future test year; however, it does represent a departure from long-standing Department precedent
    - Concern with uncertainty in future test year estimates must be weighed against the alternative approaches utilized to address revenue attrition
- A future test year approach provides essential regulatory oversight of costs, and growth of costs, through a rate case where the EDCs bear the burden of proof on the reasonableness of their estimates and forecasts
    - Improved regulatory oversight and scrutiny of forward-looking expenses limits cost growth ahead of expenditure, after which is more difficult to demonstrate imprudence
    - Increased litigation burden associated with adjudicating future test years during rate case, but other jurisdictions use suggest a transitory learning curve and replaces contentious and onerous design issues with other revenue attrition mechanisms

Future test years can be paired with well-defined protections

- Litigation burden (e.g., full discovery, cross-examination, prudence review, and line-item adjustments) and information asymmetry can be mitigated by guidelines and filing requirements that protect ratepayers
    - Reasonable limitations on in-service dates of projects during the test year, including partial-year revenue treatment for projects, cost recovery deferral for delays or failure to place in-service during test year
    - Use of budget-to-actual review to disincentivize EDCs from overestimate costs in rate case, overestimates provide additional near-term revenues but will result in lower representative levels for cost category in future rate cases
- Without a stay-out period, a utility may file more frequent rate cases; however, that provides an important venue to protect ratepayers' interests
    - Sound regulatory practice and common ratemaking and accounting approaches are still available to address large rate increases (e.g., deferrals, affording regulatory asset treatment, etc.)

See: Expert Presentation, Tools of Utility Regulation (September 8, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025)

Discontinue revenue decoupling to incentivize EDCs to promote and expedite electrification strategies

Recoupling provides opportunity for utility performance to counteract revenue attrition

- Discontinuing revenue decoupling allows for the elimination of capital cost recovery mechanisms and other attrition relief mechanisms that increase electricity rates and shift risk to ratepayers
  - EDCs will have opportunity to address revenue attrition between rate cases through promoting electrification load growth, interconnection of new loads, and DER interconnection with export tariff
  - Revenue growth can support capital investments necessary to maintain safe and reliable service as well as meet Massachusetts clean energy policy goals
- EDCs can mitigate rate increases by increasing revenues and controlling cost growth
  - Earnings growth is driven by asset utilization, reducing the need for rate increases
- Recoupling can also provide ratepayer relief by prompting company-sponsored customer incentives (e.g., EV make-ready incentive, heat pump rebates and associated performance incentives, etc.) without contemporaneous recovery from ratepayers

Revenue decoupling is not necessary to maintain commitment to demand-side resources

- Revenue decoupling was instituted to remove the EDCs disincentive to promote demand-side resources (e.g., energy efficiency, conservation, distributed generation)
- EDCs required to implement all cost-effective demand resources and subject to performance incentives and financial penalties
- Demand-side resources are now supported through a profoundly more robust portfolio of strategies outside of EDCs' control than existed when revenue decoupling was adopted
  - Increased price signal for conservation and distributed generation
  - Expansion of federal and state appliance efficiency standards
  - Strengthening of building costs, including stretch and specialized energy codes
- Implementing time of use rates also equip customers with price signals to manage load, and EDCs can further be incentivized to promote load management through performance mechanisms

See: Expert Presentation, Decoupling and Capital Recovery (October 22, 2025); Targeted Conversation, Decoupling and Capital Recovery (October 27, 2025)

Recoupling will be necessary precondition to drive cost-effective and affordable load growth

DPU has previously recognized the opportunity discontinuing revenue decoupling presents

- In 2022, DPU made a general policy pronouncement and determined that discontinuing revenue decoupling for EDCs was warranted to ensure their business models align with Massachusetts energy and environmental policy goals and ratepayer interests
  - Electrification is necessary to achieve the Commonwealth's greenhouse gas emission reduction mandates, and will increase electricity consumption
  - EDCs need to embrace increasing electric loads to support accelerating fuel/technology switching at scale
- DPU directed each EDC to submit a proposal for discontinuing full revenue decoupling in next base distribution case; however, all EDCs operate under revenue decoupling
  - DPU noted it would assess whether revenue decoupling is warranted in the next rate case

Aligning utility incentive and performance with Commonwealth's policy goals

- EDCs must have a stake in the timing and extent of electrification and decarbonization, particularly given the EDCs use these policy goals to justify investment growth
  - EDCs have an incentive to build out infrastructure to support electrification, but minimal stake in load growth materializing under revenue decoupling
  - Electrification load growth is essential to affordability, particularly given proactive investments, and EDCs must have a financial interest in that
  - Recoupling incentivizes EDCs to promote and expedite electrification strategies through pursuit of additional rebates, zero-cost equipment and installation, equipment leasing, on-bill financing, promotional price, etc.
- EDCs are uniquely positioned to leverage relationships with customer and other electrification-enabling service providers to accelerate deployment of electrification technologies

See: Expert Presentation, Decoupling and Capital Recovery (October 22, 2025); Targeted Conversation, Decoupling and Capital Recovery (October 27, 2025)

Eliminate overdependence on capital cost recovery mechanisms following reintroduction of recoupling

Transition capital trackers into base distribution rates at next rate case

- Capital cost recovery mechanisms (i.e., capital trackers), or successor capital recovery mechanisms (e.g., K-bar) provide revenue support between rate cases by escalating electricity rates
- Use of capital trackers has proliferated to support capital investments and other priority investments and policies
- Prospectively increasing electricity rates jeopardizes electrification load growth and threatens ratepayers with stranded costs
- Capital trackers shift financial risk from utilities to ratepayers, reduce cost control incentives, and limits regulatory oversight provided through full rate case
- Shift existing capital trackers into base distribution rates at next distribution rate case, including reconciling mechanisms for ESMPs, AMI, grid modernization, ISRE, and utility-owned solar

Base distribution rate recovery maintains critical cost control incentive and comprehensive review of utility financial needs

- Capital trackers prioritize cost recovery, reducing EDCs incentive for investment efficiency (i.e., utilizing operational approaches in lieu of capital expenditure) and diminishing opportunity for customer-sited resources or behaviors to defer/avoid investments
- Capital recovery mechanisms outside of base distribution rates obscures available funds for future capital expenditures
  - Depreciation expense funds provide revenues to support ongoing investments

Capital cost recovery mechanisms
Grid modernization
Advanced metering infrastructure
Provisional system plan
Electric vehicle program
Infrastructure, safety, reliability, and electrification
Electric sector modernization plan

See: Expert Presentation, Tools of Utility Regulation (September 8, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025); Expert Presentation, Decoupling and Capital Recovery (October 22, 2025); Targeted Conversation, Decoupling and Capital Recovery (October 27, 2025)

Design and implement load management performance mechanism to incentivize EDCs to drive efficiency and affordability

Management of load growth can promote, rather than erode, affordability

- Load management is a set of policies and technologies used to **reduce or shift demand during peak hours or in constrained regions**
- DOER's forthcoming Technical Potential of Load Management Study and Peak Potential Report and Recommendations will quantify the potential for peak load reduction and outline a load management strategy to save ratepayers money
- **Improving system efficiency and utilization of the electric grid mitigates rate increases** by deferring or avoiding system investments, which EDCs have limited incentive to do
- Load management performance mechanisms should focus on **system-wide load management and load management for constrained regions** (e.g., 10% most constrained substations)

PIMs are a tool to align utility incentives with desired outcomes

- PIMs should be **outcome-based**, rather than program specific and complement other regulatory tools
- Effective PIMs are **difficult to design** and should be reserved for behaviors that have **substantial impact** or otherwise are not incentivized
- **Load management PIMs should incentivize performance on load factor** (i.e., outcome) rather than specific measures (e.g., batteries, smart thermostats) to incentivize the EDC to innovate and leverage underutilized opportunities with existing resources (e.g., distributed energy resource management systems, AMI, rate design, etc.)
- **Shared savings mechanism for cost-effective non-wires alternative (NWA) projects** can encourage the utilization of concrete NWAs and share net benefits between utility and ratepayers

See: Expert Presentation, Performance Mechanisms (November 10, 2025); Targeted Conversation, Performance Mechanisms (November 19, 2025)

DOER recommends further exploration of emerging ratemaking approaches following recommendations

Evaluate a regulatory sandbox approach to scale solutions for the grid and customers

- Evaluate regulatory sandbox to test innovative products and services (e.g., Connecticut's Innovative Energy Solutions Program)
  - Creates a regulatory space that enables the ability for innovations to provide wide-spread benefits to the grid and ratepayers
  - Allows for participation pathways for EDCs, third-parties, or collaborative partnerships
- Regulatory sandbox need not simply be a ratepayer-funded pilot, rather a mechanism that supports identifying pathway for implementation and scaling beyond pilots

Explore broader CapEx-OpEx equalization mechanisms

- CapEx-OpEx equalization refers to a set of strategies that intend to create an incentive for operational expenditure (opex) equivalent to utility's incentive to pursue capital expenditure (capex)
- CapEx-OpEx equalization may mitigate capital preference and support investment efficiency
  - Financially rewards utilities to pursue least-cost, highest value solutions
- DOER recommends **targeted PIMs, shared savings mechanisms**, and opex capitalization where appropriate in the near-term
- Broader mechanisms such as total expenditures (totex) ratemaking, which treats capex and opex equivalently for ratemaking purposes; requires further consideration for application in the United States and Massachusetts
  - Other states investigating totex ratemaking approaches (e.g., Connecticut)

See: Expert Presentation, Tools of Utility Regulation (September 8, 2025); Targeted Conversation, Tools of Utility Regulation (September 17, 2025); Expert Presentation, Multi-Year and Formula-Based Rates (September 29, 2025); Expert Presentation, Performance Mechanisms (November 10, 2025); Targeted Conversation, Performance Mechanisms (November 19, 2025)

Process & Implementation Recommendations

20 min

DOER recommends two distinct proceedings to sequentially address interdependent issues

1

Address delivery charges on customers' bills

- Transition several reconciling mechanisms into base distribution rates in the EDCs next rate case (e.g., grid mod factor, AG consulting expense, electronic payment recovery, etc.)
- Convert residential assistance factor and energy efficiency reconciliation factor to non-bypassable fixed charges before EDCs next rate case

2

Enable time-varying supply rates

- Implement default time-of-use rates for Basic Service customers across service territories as soon as practical (i.e., 2028) to provide customers greater control over electric bills and to secure full benefits from ratepayer-funded AMI investments
- Resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculations, accelerate switching, and dynamic, rate-ready TVR, which will enable municipal aggregations to offer time-varying supply products
- TOU Basic Service will establish a baseline or price-to-compare to promote adoption of TOU supply rates more broadly, while preserving the ability of aggregations to offer advanced rates (e.g., critical peak pricing)

Sequencing investigation of recommendations supports timely and productive review

1

Adjustment to delivery charges should precede cost study and distribution rate design for rate cases

- A decision to transition reconciling mechanism into base distribution rates will impact the cost study and rate design for distribution service
- Conversion of volumetric reconciling mechanisms into non-bypassable fixed charges; however, does not need to occur in rate case, nor should impact design of time-varying rates

2

Determining wholesale supply-driven peak periods and design should precede transmission and distribution rate design

- With an identified TOU design and peak period, EDCs will be able to design transmission and distribution rates
- Distribution rate design should be informed by marginal cost study in rate case; however, transmission rate design can happen outside of a rate case

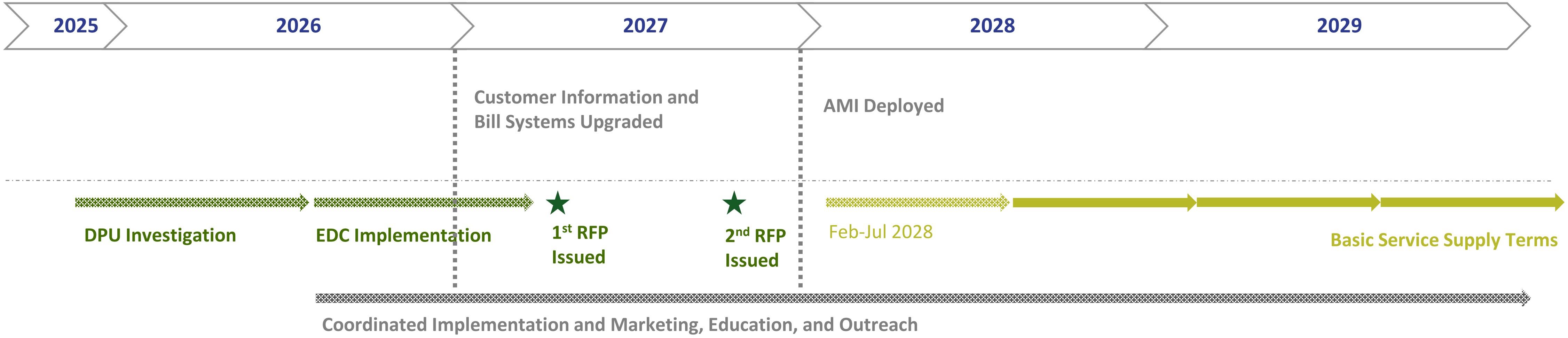
3

Reviewing regulatory mechanism recommendations from DOER petition may be appropriate before reviewing rate design recommendations

- Rate design recommendations not addressed in the proceedings above may be better suited following further direction
- Regulatory mechanism recommendations will require adjudication following a generic inquiry, in many cases implementation will need to take place in rate case

Timely implementation of time-varying supply

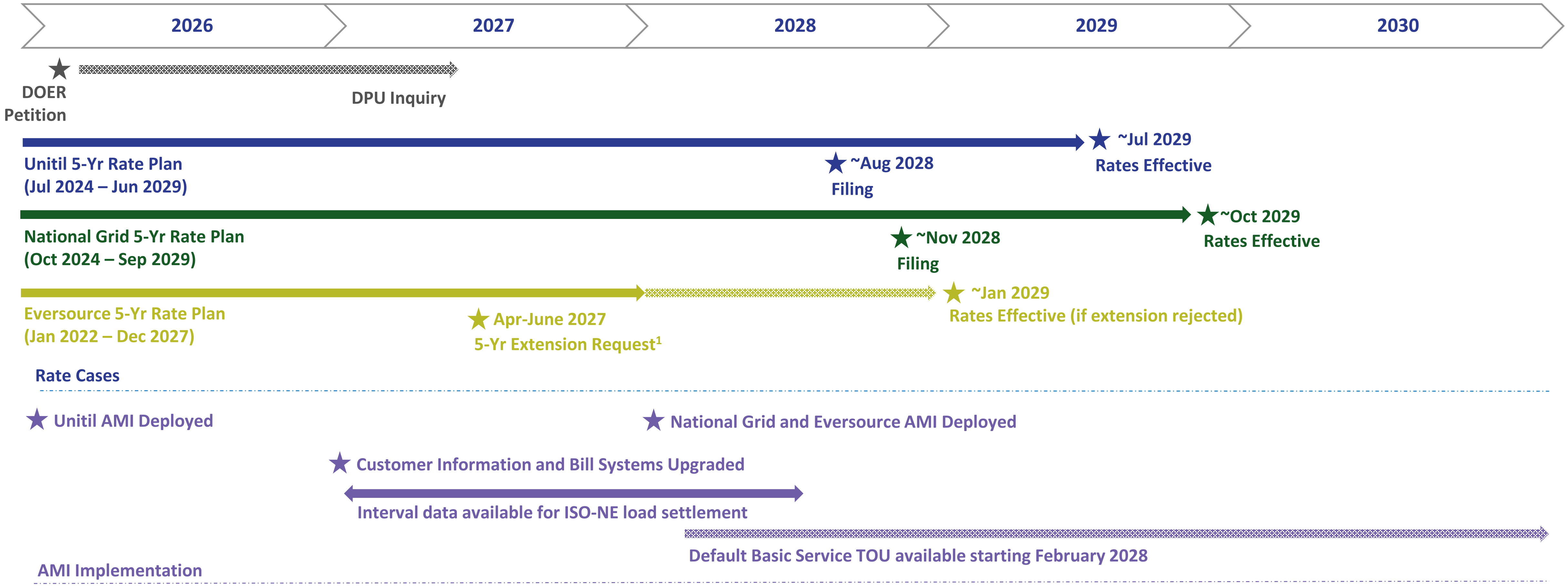
Prompt action necessary to provide for DPU investigation of time-varying supply issues and EDC preparation ahead of Basic Service procurements



- Proposed timeline leverages capabilities of ratepayer-funded AMI investments as soon as practical (i.e., 2028) to provide customers greater control over electric bills and to secure full benefits
- Basic Service procurements are on staggered 6-month schedule and are reviewed and approved by DPU, missing key dates above likely to result in delays of 6-month increments
- DPU investigation should also resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculations, accelerate switching, and dynamic, rate-ready TVR, which will enable municipal aggregations to offer time-varying supply products

Implementation considerations for ratemaking reform

DOER petition in early 2026 will provide the DPU an opportunity to investigate delivery TVR and ratemaking mechanisms for implementation before the EDCs next rate cases



[1] Eversource may file a request to extend its PBR plan term another five years no earlier than 9 months and no later than six months prior to termination of initial term. If the Department rejects the extension request, the stay-out provision shall be extended by approximately one-year to provide Eversource time to prepare a base distribution rate filing. DPU may initiate procedural discussions with Eversource and other stakeholders on timing of the rate case filing D.P.U. 22-22 at 55-56.

DOER petition will call for an inquiry into regulatory mechanism and distribution rate design recommendations

Comprehensive review of ratemaking practices can prioritize affordability, in addition to development and operation of an efficient electric power system

- DOER's forthcoming petition will include a straw proposal detailing the rate design and regulatory mechanism recommendations provided herein, subject to revision following Task Force written comment, for DPU consideration
- IRWG and Task Force process, stakeholder engagement, and evaluation of issues will better equip the DPU to investigate and determine next steps
- An investigation provides the platform for the DPU to fully consider ratemaking issues and to provide direction and guidance for timely action and implementation across all EDCs
- Many rate design and regulatory mechanisms will need to be implemented during the EDCs next rate cases

Next Steps and Closing

5 min

DOER requests comments on its recommendations by December 19, 2025

DOER welcomes comments beyond its recommendations, but specifically requests comments on the following issues

Rate Design

- Consolidated peak period TOU rate
- Cost-reflective TOU rate design
- Default opt-out
- Supply, distribution, and transmission
- Seasonality
- Peak periods
- Bill protections
- Implementation
- Marketing, education, and outreach
- Monitoring and evaluation
- Public benefits fixed charge
- Future and flexibility of rate design

Regulatory Mechanism

- Reconciling mechanisms
- Marginal cost of service study
- Export tariff
- Revenue-cap formula and stay-out provisions
- Future test year
- Revenue decoupling/recoupling
- Capital cost recovery mechanisms
- Load management performance mechanism
- Emerging regulatory approaches (e.g., regulatory sandbox, broad CapEx-OpEx equalization mechanisms)

Process & Implementation

- Proceeding on delivery charges
- Proceeding on time-varying supply rates
- Sequencing investigation of recommendations
- Timing of time-varying Basic Service and availability of third-party supply products
- Timing of inquiry for ratemaking reform
- DOER's petition substance and form

Submit comments to austin.dawson@mass.gov by <u>December 19, 2025, at 12:00pm</u>

MASSACHUSETTS
DEPARTMENT OF
ENERGY RESOURCES

Thank You!

Rate Design Key Topics

Topic 1: Time of Use Rates

I. ISO-NE Perspective on Rate Designs

ISO-New England, Dennis Cakert

Present on the wholesale markets and costs for energy, capacity, and transmission in New England and their relevance to the design and implementation of variable retail rates

II. Time of Use Rate Design in Maine

Maine Public Utilities Commission, Chair Phillip L. Bartlett II

Present Maine’s process for developing time of use rates and its most recent findings and recommendations

III. Marginal Cost Studies & Application for Rate Design

Charles River Associates, Amparo Nieto

Present approach of marginal cost-of-service studies and the use of the marginal cost-of-service study in supporting time-of-use period analysis in establishing delivery rate design

IV. Maryland TOU Process

Molly Knoll, Former Co-Chair of Maryland Rate Design Work Group

Present on Maryland’s process to design TOU rates through the Rate Design Work Group

Default seasonal TOU rates maximize customer price signals when reflecting cost-reflectivity of each electricity service.

- Cost-reflective rates can reduce growth in total system costs and are essential to an affordable energy future.
- When (and where) energy is used is more important than lower energy use, though our existing retail electricity rates prioritize the latter, and TOU rates can communicate the former.
- Electricity rates reflect several components of service (i.e., supply, transmission, distribution, and other programs/policies), and each have unique cost drivers to account for in rate design.
- It is appropriate to time-vary at least a portion of energy supply, transmission, and distribution service to achieve a cost-reflective rate design for customers that will incentivize behaviors to maximize benefits to the system.

Topic 2: Alternative Rate Design

I. Policy Fixed Charge

Department of Energy Resources, Mike Giovanniello

Present on IRWG's recommendation to consider non-bypassable fixed charge for policy costs

II. Overview of Long-Term Advance Rate Designs

Current Energy Group, Ron Nelson

Present a high-level overview of advanced rate designs, including critical peak pricing, export tariffs, non-firm tariffs, real-time pricing, and day-ahead tariffs

III. Residential Demand Charges

Electric Distribution Companies

Present on the use and the implications of demand charges for residential customers

II. Key Concepts and Options of Advanced Rate Design

Regulatory Assistance Project, Mark LeBel

Present an overview of key background and theory of advanced rate design and associated concepts and options

Rate design is an underutilized strategy to empower customers to take control of their energy costs.

- Alternative rate designs empower customers to leverage resources (e.g., demand-side resources) in a manner that reduces bills, improves system efficiency, and reduces system investment needs.
- Cost-reflective rate design and load flexibility are equally important for commercial and industrial customers even though the IRWG and Task Force have been focused on residential customer rate designs.
- Well-designed alternative rate designs may be appropriate for different services to maximize cost-reflective price signals for customers, such as critical peak pricing for supply service, demand charges for distribution and/or transmission service, or fixed charges for policy or program costs.

Topic 3: Bill and DER Impacts Expert Presentations

I. IRWG Bill Impact Recommendations

Massachusetts Clean Energy Center, Sarah Cullinan

Present recommendations for more granular bill impact analysis

II. Opportunities and Challenges in Rate Design

Energy & Environmental Economics, Inc., Ari Gold-Parker & Vivan Malkani

Present on the Household Energy Expenditure Model (HEEM) for considering bill impacts, implications of cost-reflective rates for bills, DERs, and complementary programs

III. Evolution of DER Programs in Hawai'i

Hawaii Public Utilities Commission, Abby Austin & Clarice Schafer

Present the implementation of long-term DER programs in Hawaii that includes smart DER tariffs and bring-your-own-device tariffs

IV. Impacts on Existing DER Policies & Incentive Programs

Massachusetts Department of Energy Resources, Samantha Meserve

Present the impacts of time of use rates on existing policies and programs that incentivize solar and storage resources in the Commonwealth

TOU rates will impact customer bills and existing DER programs.

- Additional data resources and availability enable more granular bill impact analysis for evaluating rate designs but will be particularly essential in assessing affordability and other impacts to vulnerable customers.
- Rate design and complementary programs have supported adoption and use of DERs thus far. Continued coordination during the transition will be necessary to ensure clear and fair customer price signals are aligned with system costs and other grid benefits.
- TOU rates can provide price signals to encourage DER dispatch and load management and will need to complement existing policies or programs, such as net energy metering, Solar Massachusetts Renewable Target (SMART), managed charging programs, and portfolio standards (e.g., Clean Peak Energy Standard).

Topic 4: Implementation and Protections

I. Dr. Nock's IRWG Recommendations

Peoples Energy Analytics & Carnegie Mellon University, Dr. Destenie Nock

Present on the Dr. Nock's recommendation to the IRWG on the Near- and Long-Term Reports

II. Lessons & Strategies for Implementing TVR

Synapse Energy Economics, Melissa Whited

Present on customer acceptance, cautionary tales, and other recommendations for implementing default time-varying rates (TVR)

III. Reflections on California's TOU Transition

California Public Utilities Commission, Paul S. Phillips

Present on current and future pricing strategies for electrification, decarbonization, and affordability in California

IV. AMI and TVR Implementation

Massachusetts Electric Distribution Companies

Present on the timeline and status of advanced metering infrastructure (AMI) deployment and future capabilities to offer TVR

Implementing default TOU rates will benefit customers.

- The IRWG's recommendation of a default TOU rate for residential customers that varies supply, transmission, and distribution may necessitate a phased rollout; this will allow customers to adjust to an increasing portion of their rate and bill being exposed to time-varying costs.
- To implement the TOU rate as recommended, the EDCs need DPU direction on an approved end state and glidepath for transition (similar to the California Energy Commission's decision that provided a blueprint for implementing TOU).
- Robust customer education and tools (e.g., a rate comparison tool) are critical resources and may need to be supplemented by further customer protections.
- Default and/or opt-out TOU rates will maximize customer and system benefits, and customer protections can mitigate any adverse consequences.

Topic 5: Marketing, Education, and Outreach

I. Marketing, Education, & Outreach (MEO)

Hawks Peak Strategies, Dr. Courtney Henderson

Present on the opportunities to leverage MEO to better serve customers and the IRWG near- and long-term recommendations

II. Missouri's Time of Use (TOU) Experience

Missouri Office of the Public Counsel, Geoff Marke, PhD

Present on the rollout of TOU in Missouri, the opportunity of TOU rates, and lessons learned

III. MEO for TVR – Best Practices Across U.S.

GridX, Michael Pirro

Present on best practices and common challenges in implementing TVR, in addition to a case study of customer experience and education

IV. Dynamic Rates Engagement

Oracle, Samantha Caputo

Present on leveraging AMI for customer engagement and empowerment through the deployment of dynamic rates, in addition to a case study of a utility deployment

V. Embedded Intelligence in the Electric Grid

Sense, Mike Phillips

Present on the opportunities of edge computing and real-time applications for customer engagement and home/grid optimization

MEO is key to an effective rollout of TOU rates.

- An effective MEO plan identifies potential barriers to participation, tailors MEO efforts to mitigate and remove those barriers, and uses meter energy usage data to target communications to individual households about opportunities to reduce their financial burden.
- The IRWG's MEO recommendations are a good guide for MEO efforts and should be further refined and expanded upon with the help of stakeholders, customers, and MEO professionals.
- Consider politics during roll-out: get stakeholder buy-in and have clear, consistent, and targeted communication and education.
- Customers are inundated with advertising, but with the help of new technologies, utilities are well positioned to offer targeted, effective tools to communicate about the potential benefits of TOU rates for customers.

Regulatory Mechanism Key Topics

Topic 1: Ratemaking and Massachusetts Utilities

Background

Purpose: Present the IRWG's Massachusetts Regulatory Framework Primer and explore drivers behind the practices and potential changes in ratemaking and regulatory mechanisms in place today. The presentations prioritize consideration of challenges and opportunities in the regulatory framework to advance a decarbonized energy future.

Context: The IRWG recommends the Task Force consider a comprehensive regulatory framework that will effectively support the Commonwealth's clean energy and climate goals and expects a DPU investigation will be a necessary step to critically and comprehensively examine the regulatory framework considering the meaningful change to the DPU's authority and priorities pursuant to recent legislation.

Expert Presentations

I. Massachusetts Electric Regulatory Framework

Massachusetts Department of Energy Resources, Austin Dawson

Present an overview of existing Massachusetts regulatory framework for electric distribution companies, based on the Massachusetts Regulatory Framework Primer

II. Utility Operations and Challenges in Massachusetts

Massachusetts Electric Distribution Companies

Present on the current and future demands of the electric power system and the challenges to electric utilities as we decarbonize and electrify

III. Electric Sector Modernization Plans, Grid Modernization Advisory Council, and Distribution System Planning

Massachusetts Department of Energy Resources, Aurora Edington

Present on the current landscape of distribution system planning and grid modernization activities and proceedings in Massachusetts, focused on the Electric Sector Modernization Plans (ESMPs) and the Grid Modernization Advisory Council (GMAC)

IV. Utility Regulatory Innovation for the Energy Transition

Analysis Group, Daniel Stuart

Present on policy innovations to support the electric distribution system transition (e.g., integrated distribution system planning, pre-authorization of investments, future test years, etc.), based on Massachusetts Energy Transition: Innovation for Electric Utility Regulation

Topic 2: Tools of Cost-of-Service Regulation

Background

Purpose: Present the use of allocated cost-of-service studies and historical test years in establishing revenue requirements, in addition to alternatives to a historical test year. The presentations will prioritize consideration of opportunities to modernize cost studies and test years. The presentations will also include an evaluation of innovative approaches to ratemaking.

Context: MA relies on allocated cost-of-service studies and no longer requires EDCs to provide marginal costs of service studies; the widespread adoption of TVR may necessitate a reevaluation of this practice. Massachusetts has also relied on a historical test year for rate cases; increasingly the amount of revenue subject to a historical test year is decreasing as more costs are recovered through reconciling mechanisms.

Expert Presentations

I. Reconciling Mechanisms, Riders, and Trackers in Massachusetts

Massachusetts Department of Energy Resources, Austin Dawson

Present on the current approaches and utilization of reconciling mechanisms, commonly referred to as riders and trackers, in Massachusetts

II. Allocated Cost Studies & Historical Test Years in Massachusetts

Massachusetts Electric Distribution Companies

Present on the current approach to allocated cost-of-service studies (ACOSS) and the development and application of historical test years in Massachusetts

III. Future and Multi-Year Test Years

Public Service Commission of Wisconsin, Commissioner Kristy Nieto

Present the applications and use of future and multi-year test years in Wisconsin regulatory environment to support oversight over expanding levels of investment to support load growth

IV. CapEx/OpEx Equalization

RMI, Gennelle Wilson & Current Energy Group, Dan Cross-Call

Present on CapEx-OpEx equalization mechanisms, with examples including totex ratemaking as employed in Great Britain's Revenues = Incentives + Innovation + Outputs (RIIO) framework

Topic 3: Multi-Year and Formula-Based Rates

Background

Purpose: Present the advantages and disadvantages of multi-year and formula-based rates and to what extent either would be impacted by changes in other regulatory or ratemaking approaches being considered in the Task Force. The presentations prioritize an evaluation of the durability of multi-year rate plans following impacts to the other ratemaking and regulatory mechanisms.

Context: Massachusetts' EDCs have operated under PBR plans or PBR-like mechanisms for the greater part of two decades. The use of revenue cap formulas and K-bar adjustments for the EDCs is a more recent practice, and currently all three EDCs are under a five-year stay-out.

Expert Presentations

I. Performance-Based Regulation in Massachusetts

Massachusetts Electric Distribution Companies

Present on the current application and operation of the utilities' revenue cap (I-X) formulas and supporting mechanisms in Massachusetts

II. Multi-Year and Formula-Based Rates

Pacific Economics Group, Mark Newton Lowry

Present on the theory and application of multi-year rate plans and formula-based rates for electric distribution companies

III. Multi-Year Rate Plan and PBR Approaches

Current Energy Group, Matthew McDonnell

Present an overview of peer jurisdictions that have implemented various PBR revenue adjustments, including MYRPs, ESMs, and approaches to capital expenditure and operation expenditure

IV. Consumer Advocate Perspective on Multi-Year Rate Plans

Maryland Office of People's Counsel

Present analysis and position on multi-year rate plans and formula-based rates, in addition to lessons learned from Maryland's pilot multi-year rate plan

Topic 4: Decoupling and Capital Recovery

Background

Purpose: Present on revenue decoupling in the context of load growth and the interaction with incremental capital recovery needs. The presentations prioritize consideration of evolving needs to scale electrification efforts to meet statutory limits in the building and transportation sectors and the potential to align utility support.

Context: Massachusetts has increasingly relied on capital cost recovery mechanisms, or authorized adjustments to revenue between rate cases, to support grid investments, which has been driven in part due to stagnant sales growth. The reevaluation of revenue decoupling in Massachusetts may be suited to support strategic electrification and the utilities' need for incremental revenue support between rate cases.

Expert Presentations

I. Revenue Decoupling in Massachusetts

Synapse Energy Economics, Tim Woolf

Present the origins and drivers under which the DPU implemented revenue decoupling in Massachusetts

II. Evolving Role of Energy Efficiency

Massachusetts Department of Energy Resources, Liz Reichart

Present the existing landscape of pursuing all cost-effective energy efficiency and the implementation of performance standards, building codes, and other market transformations

III. Capital Recovery Needs and Mechanisms

Massachusetts Electric Distribution Companies

Present on the utilities need for incremental capital recovery or revenues to support growing investments and the current mechanisms that support those needs (e.g., K-Bar)

IV. Future of Revenue Decoupling

Massachusetts Department of Energy Resources, Austin Dawson

Present on the challenges with revenue decoupling and the opportunities associated with modifying the existing approach to revenue decoupling

Topic 5: Performance Mechanisms

Background

Purpose: Present on the role of performance mechanisms as a central component to a regulatory framework driving widespread electrification, decarbonization, & affordability. The presentations prioritize consideration of available mechanisms and innovative approaches to measuring utility performance.

Context: The use of performance mechanisms in Massachusetts predates the modern use of PBR and is not always directly tied to PBR plans (e.g., timeline enforcement mechanism, EE incentives). The design and use of performance mechanisms must be careful, balanced, and focused on outcomes. The continuous expansion of reporting, scorecard, and performance incentive mechanisms risks increasing administrative burden for utilities, regulators, and stakeholders.

Expert Presentations

I. Performance Mechanisms in Massachusetts

Massachusetts Electric Distribution Companies

Present on the current use of performance mechanisms, including PBR metrics, service quality standards, and timeline enforcement mechanisms

II. Performance Mechanisms in Other Jurisdictions

Synapse Energy Economics, Melissa Whited

Present on performance mechanisms utilized in other jurisdictions (e.g., load factor PIM, DER interconnection PIM, shared savings mechanisms)

III. PIMs: From Design to Evaluation

RMI, Carina Rosenbach

Present on the PIM lifecycle and design approaches

IV. Performance Mechanisms on Load Management

Massachusetts Department of Energy Resources, Charles Dawson

Present on forthcoming analysis and policy recommendations of DOER's Peak Potential Study, exploring load management strategies for an affordable net-zero grid